Pennsylvania Public Utility Commission, et al. v. Columbia Gas of Pennsylvania, Inc. Evidentiary Hearing	Docket No.: R-2021-3024296

Pages 131 - 245

Judge's Chambers
Piatt Place
301 5th Avenue
Pittsburgh, PA
Wednesday, August 4, 2021
Commencing at 10:11 a.m.

INDEX TO EXHIBITS

Docket No. R-2021-3024296

Hearing Date: August 4, 2021

NUMBER

Columbia Gas of Pennsylvania Exhibits:

Exhibit 1	3/30/21		
	Initial Filing		
Gas RR-26	Revised Version		
Gas RR-53	Revised Version		
Statement 1	Direct Testimony		
	Of Mark Kempic		
Statement 1-R			
	Rebuttal Testimony		
	Of Mark Kempic	200	202

INDEX TO EXHIBITS (cont.)

NUMBER

Columbia Gas of Pennsylvania Exhibits:

INDEX TO EXHIBITS (cont.)

INDEX TO EXHIBITS (cont.)

NUMBER		FOR IDENTIFICATION	IN EVIDENCE

Columbia Gas of Pennsylvania Exhibits:

Statement 6-R
Rebuttal Testimony of
Nicole M. Shultz w/Exhibits
NMS-1 and NMS-2

Statement 7 Direct Testimony of
Ray Brumley

Statement 7-R
Rebuttal Testimony of
Ray Brumley

Statement 8 Direct Testimony of
Paul R. Moul

Statement 8-R
Rebuttal Testimony of
Paul R. Now

Exhibit 400-R
Document
(PART OF STATEMENT 8-R)

INDEX TO EXHIBITS (cont.)

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NUMBER

Office of Consumer Advocate Exhibits:

Statement 3-SR
Surrebuttal Testimony of
Jerome D. Mierzwa

Statement 4 Direct Testimony of
Roger D. Colton

Statement 4-R
Rebuttal Testimony of
Roger D. Colton

Statement 4-SR
Surrebuttal Testimony of
Roger D. Colton

Office of Small Business Advocate Exhibits:

Statement 1 Direct Testimony of
Robert D. Knecht w/Exhibits
IEC-1, IEC-2

(EXCEL WORKBOOK TO BE INCLUDED)

Statement 1-R
Rebuttal Testimony of Robert D.
Knecht w/Exhibit IEC-1

(EXCEL WORKBOOK TO BE INCLUDED)

INDEX TO EXHIBITS (cont.)

NUMBER		FOR IDENTIFICATION	IN EVIDENCE

Office of Small Business Advocate Exhibits:

Statement 1-S

Surrebuttal Testimony of
Robert D. Knecht w/Exhibit I
EC-1S

(EXCEL WORKBOOK TO BE INCLUDED)

CAUSE-PA Exhibits:

Statement 1 Direct Testimony of
Harry Geller w/Appendix A,
B and C

Statement 1-SR

Surrebuttal Testimony of
Harry Geller w/Appendix
A and B

Mr. Culbertson Exhibits:

Exhibit A NiSource Representation
To Investors

Exhibit B Table from Exhibit A

Exhibit C NiSource 10K

INDEX TO EXHIBITS (cont.)

INDEX TO EXHIBITS (cont.)

NUMBER

Mr. Culbertson Exhibits:

Exhibit L Management Operations Audit

Exhibit M NiSource Code of Business Conduct

(NOT ADMITTED/NOT ATTACHED)

Statement Direct Testimony of Richard Culbertson

Statement Surrebuttal Testimony Of Richard Culbertson

Columbia Industrial Intervenors Exhibits:

Statement 1 Rebuttal Testimony of Frank Plank

Penn State University Exhibits:

Statement 1 Direct Testimony of James L. Crist w/Exhibit PSU-1

Statement 1-R Rebuttal Testimony of James L. Crist

INDEX TO EXHIBITS (cont.)

NUMBER

Penn State University Exhibits:

Statement 1-SR

Surrebuttal Testimony of

James L. Crist w/Exhibit

PSU-SR-1

PA Weatherization Providers Task Force Exhibits:

Statement 1 Direct Testimony of

Eugene M. Brady

Amy E. Hirakis
Senior Counsel
Legal Department

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Phone: 717.210.9625
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March 30, 2021

VIA E-File

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17210-3265

Re: Columbia Gas of Pennsylvania, Inc. Supplement No. 325 to Tariff Gas Pa. P.U.C. No. 9. Docket No. R-2021-3024296

Secretary Chiavetta:

Enclosed for filing on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia") is Supplement No. 325 to Tariff Gas Pa. P.U.C. No. 9 ("Supplement No. 325"), submitted pursuant to 66 Pa.C.S. § 1308, along with all supporting exhibits, standard data responses, and testimony required to be submitted in conjunction with a tariff change seeking a general rate increase. Supplement No. 325, issued March 30, 2021, to be effective May 29, 2021, changes Columbia's base distribution rates, and removes, revises, and adds various tariff provisions, and is submitted in compliance with the Pennsylvania Public Utility Commission's ("Commission") regulations, the Commission's Emergency Order at Docket No. M-2020-3019262 and directives related to e-Filing documents with the Secretary's Bureau.

Columbia's filing reflects an overall revenue increase of approximately $98.3 million per year. Pursuant to the proposed rates in Columbia's filing notice, which includes the most recently effective gas cost rates, the total bill for a residential customer who purchases 70 therms of gas from Columbia per month would increase from $100.77 to $115.37 per month, or by 14.49 percent. The total bill for a small commercial customer using 150 therms of gas purchased from Columbia per month would increase from $164.92 to $187.30, or by 13.57 percent. The total bill for a small industrial customer using 1,316 therms of gas from Columbia per month would increase from $1,164.10 to $1,296.34 per month, or by 11.36 percent.

The filing consists of thirteen volumes, and is organized as follows:

Standard Filing Requirements	***Book***
Exhibits 1 – 3	Vol 1 of 10
Exhibit 4	Vol 2 of 10
Exhibits 5 – 12	Vol 3 of 10
Exhibit 13	Vol 4 of 10
Exhibit 14 – 17	Vol 5 of 10
Exhibits 101 – 108	Vol 6 of 10
Exhibits 109 – 117	Vol 7 of 10
Exhibits 400 – 403	Vol 8 of 10
Exhibits 404 – 414	Vol 9 of 10
Testimony	Vol 10 of 10

Standard Data Requests
GASCOS – all
GASROR - all
GASRR - all

Columbia has provided public notice of this filing and the overall rate increase information in accordance with Section 53.45(b)(4) of the Commission's regulations. Moreover, Columbia has made this filing electronically available to the Office of Consumer Advocate, the Commission's Bureau of Investigation and Enforcement, the Office of Small Business Advocate, the Commission's Office of Special Assistants, Office of Administrative Law Judge, Bureau of Technical Utility Services, and to each of the Commissioners. Additionally, parties to the Company's most recent rate case have been served with a copy of this filing in accordance with the attached Certificate of Service. Columbia will provide hard copies of the filing upon request.

Please direct any inquiry with regard to this filing to either the undersigned, or to the Company's outside counsel, Michael W. Hassell, Post & Schell PC, 17 North Second Street, 12th Floor, Harrisburg, PA 17101-1601, (717) 612-6029.

Respectfully Submitted,

Amy E. Hirakis

Amy E. Hirakis, Esquire
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E-mail: ahirakis@nisource.com

Enclosures

cc: Chairman Gladys M. Brown Dutrieuille
Vice Chairman David W. Sweet
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora
Office of Special Assistants
Office of Administrative Law Judge
Bureau of Technical Utility Services
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served upon the following persons, in the manner indicated, in accordance with the requirements of § 1.54 (relating to service by a participant).

VIA E-MAIL

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Date: March 30, 2021

Amy E. Hirakis

Amy E. Hirakis

Date Created	Filing Number
3/30/2021	2077142

Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
Harrisburg, PA 17105-3265
EFILING - FILING DETAIL

Your filing has been electronically received. Upon review of the filing for conformity with the Commission's filing requirements, a notice will be issued acknowledging acceptance or rejection (with reason) of the filing. The matter will receive the attention of the Commission and you will be advised if any further action is required on your part.

The date filed on will be the current day if the filing occurs on a business day before or at 4:30 p.m. (EST). It will be the next business day if the filing occurs after 4:30 p.m. (EST) or on weekends or holidays.

Representing: Columbia Gas of Pennsylvania, Inc.
Docket Number: R-2021-3024296
Case Description: PA Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.
Transmission Date: 3/30/2021 2:31 PM
Filed On: 3/30/2021 2:31 PM
eFiling Confirmation Number: 2077142

File Name	Document Type	Upload Date
CPA 2021 RC - filing letter and COS.pdf	Rate Increase Filing Supporting Documents (Fixed Utility)	3/30/2021 2:31:23 PM

For filings exceeding 250 pages, the PUC is requiring that filers submit one paper copy to the Secretary's Bureau within three business days of submitting the electronic filing online. Please mail the paper copy along with copy of this confirmation page to Secretary, Pennsylvania Public Utility Commission, 400 North Street, Harrisburg PA 17120 a copy of the filing confirmation page or reference the filing confirmation number on the first page of the paper copy.

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Columbia Gas of Pennsylvania, Inc.

Standard Data Request

Revenue Requirements

Question No. RR-26-REV:

Please provide the following monthly labor data for the year prior to the HTY, the HTY and the FTY through the most recent date available.

a. number of actual employees broken down between type (e.g., salaried, union, non-union, temporary, etc.);

b. regular payroll broken down between expensed, capitalized and other;

c. overtime payroll broken down between expensed, capitalized and other;

d. temporary payroll broken down between expensed, capitalized and other; and

e. other payroll (specify).

Response:

a, b, c and e. Please see REVISED GAS-RR-026 Attachment A for the requested data.

d. The Company has no temporary employees.

Note that revisions to GAS-RR-026 do not result in any changes to the Company's claim for Labor.

Headcount Changes - NiNext Headcount Adjustment went from (16) to (3) - Information provided for the initial filing was preliminary and the assumptions have been updated.

Column 2, rows 25, 26, 32 & 33 - HTY required a change between Regular Payroll and Overtime Payroll in order to tie to Exhibit 4, Schedule 2, Page 3 "Gross Payroll Summary" for both O&M and Capital, and have no impact to "Total Payroll". The

Columbia Gas of Pennsylvania, Inc.

Standard Data Request

Revenue Requirements

initial response included a preliminary version of the Gross Payroll Summary in the supporting information.

Column 7, row 32 - NiNext Savings - Capital Amount has been updated to correspond with revised detail. Initial filing assumptions were preliminary.

Column 9, rows 25, 26, 32 & 33 - "Other" changes were needed to tie out to FTY Budget. No changes were made to the FTY budget; this column is needed as a "Tie-out" column.

Column 14, row 32 - NiNext Savings - Capital Amount has been updated to correspond with revised detail. Initial filing assumptions were preliminary.

Column 16, row 32 - "Other" changes were needed to tie out to FPFTY Budget. No changes were made to the FPFTY budget; this column is needed as a "Tie-out" column.

Description	Pre-HTY TME 11/30/2019	HTY TME 11/30/2020	Budgeted Vacancies	Ni Next Headcount Adj	FTY TME 11/30/2021	FPFTY TME 12/31/2022
Employees						
Total Clerical Labor	90	95	0	0	95	95
Total Exempt Labor	167	174	19	(3)	190	190
Total Manual - Non-Union	14	15	4	0	19	19
Total Manual - Union	492	483	24	0	507	507
Total Employees	763	767	47	(3)	811	811

Description b.,c.,d., and e	Pre-HTY TME 11/30/2019 (1)	HTY TME 11/30/2020 Per Books (2)	Rate Making Adjustments (3)	HTY TME 11/30/2020 Normalized (4)=(2)+(3)	Budgeted Vacancies (5)	NiNext Savings (7)	Wage Increase @ 3% (6)	Cap/O&M Change (8)	Other (9)
Payroll Expense									
Regular Payroll	31,713,297	31,788,065	1,628,705	33,416,770	1,957,451	(807,212)	819,444	(1,598,968)	334,273
Overtime Payroll	4,362,259	4,172,342	-	4,172,342	-	-	-	-	546,901
Premium Payroll	58,413	222,632	-	222,632	-	-	-	-	(222,632)
Net Affiliate Labor Transferred	(3,779)	200,784	-	200,784	-	-	-	-	(200,784)
Total Expense	36,130,190	36,383,823	1,628,705	38,012,527	1,957,451	(807,212)	819,444	(1,598,968)	457,758
Capital Payroll									
Regular Payroll	22,554,725	27,159,006	1,385,028	28,544,034	2,262,288	486,409	765,918	1,598,968	227,939
Overtime Payroll	3,277,396	3,520,574	-	3,520,574	-	-	-	-	(1,072,519)
Premium Payroll	43,886	187,854	-	187,854	-	-	-	-	(187,854)
Net Affiliate Labor Transferred	(2,840)	169,419	-	169,419	-	-	-	-	(169,419)
Total Capitalization	25,873,167	31,036,854	1,385,028	32,421,882	2,262,288	486,409	765,918	1,598,968	(1,201,854)
Total Payroll	**62,003,357**	**67,420,677**	**3,013,732**	**70,434,409**	**4,219,739**	**(320,803)**	**1,585,362**	**-**	**(744,096)**
Incentive Comp									
Expense	1,472,179	260,629	1,640,296	1,900,925	-	-	-	-	462,075
Capital	1,131,161	199,737	909,593	1,109,330	-	-	-	-	1,101,670
Total Incentive Comp	**2,603,340**	**460,366**	**2,549,889**	**3,010,255**	**-**	**-**	**-**	**-**	**1,563,745**

Description b.,c.,d., and e	FTY Budget (10)=Sum (4 through 9)	Rate Making Adjustments (11)	FTY TME 11/30/2021 Normalized (12)=(10) + (11)	Wage Increase @ 3% (13)	NiNext Savings (14)	Cap/O&M Change (15)	Other (16)	FPFTY Budget (17)=Sum(12 through 16)	Rate Making Adjustments (18)	FPFTY TME 12/31/2022 Normalized (19)=(17) + (18)
Payroll Expense										
Regular Payroll	34,121,757	504,421	34,626,178	975,510	(594,394)	(108,522)	6,227	34,905,000	430,280	35,335,280
Overtime Payroll	4,719,243	-	4,719,243	-	-	-	(376,243)	4,343,000	-	4,343,000
Premium Payroll	-	-	-	-	-	-	-	-	-	-
Net Affiliate Labor Transferred	-	-	-	-	-	-	-	-	-	-
Total Expense	38,841,000	504,421	39,345,421	975,510	(594,394)	(108,522)	(370,016)	39,248,000	430,280	39,678,280
Capital Payroll										
Regular Payroll	33,885,556	459,219	34,344,775	830,245	485,197	108,522	(1,138,490)	34,630,249	402,720	35,032,968
Overtime Payroll	2,448,055	-	2,448,055	-	-	-	(353,723)	2,094,332	-	2,094,332
Premium Payroll	-	-	0	-	-	-	-	-	-	-
Net Affiliate Labor Transferred	-	-	0	-	-	-	-	-	-	-
Total Capitalization	36,333,611	459,219	36,792,830	830,245	485,197	108,522	(1,492,213)	36,724,581	402,720	37,127,301
Total Payroll	**75,174,611**	**963,640**	**76,138,251**	**1,805,755**	**(109,197)**	**-**	**(1,862,228)**	**75,972,581**	**833,000**	**76,805,580**
Incentive Comp										
Expense	2,363,000	-	2,363,000	-	-	-	82,000	2,445,000	-	2,445,000
Capital	2,211,000	-	2,211,000	-	-	-	101,000	2,312,000	-	2,312,000
Total Incentive Comp	**4,574,000**	**-**	**4,574,000**	**-**	**-**	**-**	**183,000**	**4,757,000**	**-**	**4,757,000**

Date Created	Filing Number
6/9/2021	2180993

Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
Harrisburg, PA 17105-3265
EFILING - FILING DETAIL

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Docket Number: R-2021-3024296
Case Description:
Transmission Date: 6/9/2021 4:15 PM
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File Name	Document Type	Upload Date
CPA letter cos SDR REV.pdf	Letter	6/9/2021 4:15:45 PM

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June 9, 2021

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: PA Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.
Docket No. R-2021-3024296

Dear Secretary Chiavetta:

On March 30, 2021, Columbia Gas of PA, Inc. ("Columbia") filed its Standard Data Requests in the above-captioned proceeding. Attached for filing is GAS-RR-53-Revised on behalf of Columbia. Columbia intends to submit the revised version of GAS-RR-53 for the record in this proceeding. Copies will be provided as indicated on the Certificate of Service.

Respectfully submitted,

Lindsay A. Berkstresser

Lindsay A. Berkstresser

LAB/kls
Attachment

cc: Honorable Mark A. Hoyer
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served upon the following persons, in the manner indicated, in accordance with the requirements of § 1.54 (relating to service by a participant).

VIA E-MAIL

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Date: June 10, 2021

Lindsay A. Berkstresser

Columbia Gas of Pennsylvania, Inc.

Standard Data Request

Revenue Requirements

Question No. RR-053-REV:

Please describe each budgeted or planned cost savings program to be implemented during the historic or future year. Please identify the cost of implementing the program and the anticipated annual savings.

Revised Response (Revised portions are underlined):

In 2020, NiSource launched an initiative called NiSource Next, a multi-year enterprise-wide program designed to deliver long-term, sustainable capability enhancements and cost efficiency improvements. The program is structured to leverage our current scale, utilize technology, define clear accountability with our leaders and employees, and standardize processes to create an organization focused on operational rigor and continuous improvement. The overarching objectives of this program include an unwavering commitment to safety leadership, identifying savings opportunities, efficient and empowered leadership structure, enhanced digital customer service capabilities, and standardizing operations management supported by technology enhancements. Cost efficiencies achieved are expected to offset future inflationary pressure related to O&M costs.

NiSource Next is centered on the following five programs:

- A streamlined organizational structure and clearly defined roles and responsibilities
- Evolution of business services which will provide support to our employees when needed and provide opportunities to consolidate and digitize processes across supply chain, human resources, finance and customer and billing organizations
- Operational work standardization which builds from the operational rigor, risk identification and safety enhancement work underway with our Safety

Columbia Gas of Pennsylvania, Inc.

Standard Data Request

Revenue Requirements

Management System and is intended to ensure we execute work processes the best and safest way

- Enabling field mobility which will provide tools and resources to our employees when and where they are needed – we will deploy enhanced work planning and scheduling tools and provide field employees with the technology and resources they need to allow for a paperless environment, provide all information needed at the job site to support safe execution of work while improving the consistency and quality of records and operational data
- Connected customer experience which will enable us to be responsive to and empower customers by implementing digital and mobile capabilities to drive self-service, decrease call handling times through automation, and empower teams with tools to achieve high productivity in a remote work environment; we will also modernize billing practices and encourage customers to transition to paperless billing while applying analytics to more quickly address customer service needs across multiple channels.

Costs:

The cost of the NiSource Next initiative in the FPFTY is $2,452,213.
The cost of the NiSource Next initiative in the FTY is $4,917,687, less $1,182,600 of non-recurring consulting expense (Exhibit 104, Schedule 2, Page 11 of 20) and $1,900,000 of severance costs (Exhibit 104, Schedule 2, Page 14 of 20, Line 10), resulting in a net expense of $1,835,087.

Savings:

The Company has incorporated $7,380,695 of projected O&M savings related to the NiSource Next in the FPFTY.

The FTY includes $5,411,555 of projected O&M savings related to NiSource Next.

Columbia Gas of Pennsylvania, Inc.

Standard Data Request

Revenue Requirements

Original Response:

In 2020, NiSource launched an initiative called NiSource Next, a multi-year enterprise-wide program designed to deliver long-term, sustainable capability enhancements and cost efficiency improvements. The program is structured to leverage our current scale, utilize technology, define clear accountability with our leaders and employees, and standardize processes to create an organization focused on operational rigor and continuous improvement. The overarching objectives of this program include an unwavering commitment to safety leadership, identifying savings opportunities, efficient and empowered leadership structure, enhanced digital customer service capabilities, and standardizing operations management supported by technology enhancements. Cost efficiencies achieved are expected to offset future inflationary pressure related to O&M costs.

NiSource Next is centered on the following five programs:

- A streamlined organizational structure and clearly defined roles and responsibilities
- Evolution of business services which will provide support to our employees when needed and provide opportunities to consolidate and digitize processes across supply chain, human resources, finance and customer and billing organizations
- Operational work standardization which builds from the operational rigor, risk identification and safety enhancement work underway with our Safety Management System and is intended to ensure we execute work processes the best and safest way
- Enabling field mobility which will provide tools and resources to our employees when and where they are needed – we will deploy enhanced work planning and scheduling tools and provide field employees with the technology and resources they need to allow for a paperless environment,

Columbia Gas of Pennsylvania, Inc.

Standard Data Request

Revenue Requirements

provide all information needed at the job site to support safe execution of work while improving the consistency and quality of records and operational data

- Connected customer experience which will enable us to be responsive to and empower customers by implementing digital and mobile capabilities to drive self-service, decrease call handling times through automation, and empower teams with tools to achieve high productivity in a remote work environment; we will also modernize billing practices and encourage customers to transition to paperless billing while applying analytics to more quickly address customer service needs across multiple channels.

Costs:

The cost of the NiSource Next initiative in the FPFTY is $2,452,213.
The cost of the NiSource Next initiative in the FTY is $4,917,687, less $1,182,600 of non-recurring consulting expense (Exhibit 104, Schedule 2, Page 11 of 20) and $1,900,000 of severance costs (Exhibit 104, Schedule 2, Page 14 of 20, Line 10), resulting in a net expense of $1,835,087.

Savings:

The Company has incorporated $7,380,695 of projected O&M savings related to the NiSource Next in the FPFTY.

The FTY includes $4,952,318 of projected O&M savings related to NiSource Next.

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Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
Harrisburg, PA 17105-3265
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Docket Number: R-2021-3024296
Case Description:
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Columbia Gas of Pennsylvania, Inc.
2021 General Rate Case
Docket No. R-2021-3024296
Standard Filing Requirements
Testimony
Volume 10 of 10

M. KEMPIC

COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

March 30, 2021

Table of Contents

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 and Chief Operating Officer.

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 Field Operations, Construction, Safety, Pipeline Safety Compliance, Measurement & Regulation, Rates and Regulatory Policy, Governmental and Public Affairs, and Large Customer 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 served as President from 2012 until 2017, at which time I accepted a position as the Chief Transformation Officer for NiSource. In the fall of 2018, I relocated to Massachusetts at first in a temporary capacity and then I was named President and Chief Operating Officer of Columbia Gas of Massachusetts, a position I held until August of 2020. I resumed my role as President of Columbia Gas of Pennsylvania in September of 2020.

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. Previously, I testified in Columbia's numerous base rate cases before the Commission at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274, R-2015-2468056, and R-2016-2529660.

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, and discuss the objectives that Columbia seeks to accomplish in this proceeding. I will also discuss the Company's performance during 2020 and at the outset of 2021, and address Columbia's performance quality in compliance with Section 523 of the Public Utility Code.

Finally, 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 Projected Future Test Year ("FPFTY") in this base rate filing.

Q. Please describe briefly the corporate history of Columbia and its relationship with its parent company, 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 delivering natural gas service to approximately 436,000 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 3.5 million customers. 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, which has since been replaced by the Public Utility Holding Company Act of 2005.

On October 9, 2020, NiSource Inc. completed the sale of Bay State Gas Company d/b/a Columbia Gas of Massachusetts and thereby finalized the Asset Purchase Agreement entered into with Eversource, a Massachusetts voluntary association, on February 26, 2020. 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"), 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. Consistent with prior cases, the primary driver for this filing is Columbia's ongoing significant investment to enhance its distribution system through the replacement of cast iron, bare steel and first generation pipe and its expenditures on operations safety enhancements. 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 continued accelerated pipeline replacement program, as well as Columbia's operations and maintenance expenditures. 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 main 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. Despite the impact of COVID-19, throughout the pandemic Columbia, its employees, and its contractors continued to provide essential services to our customers with minimal disruption. Indeed, as detailed in the testimony of Columbia witness Brumley (Columbia Statement No. 7), in 2020, even with the global disruption to most business as a result of the pandemic, Columbia nonetheless was able to replace and retire a significant amount of pipe in 2020. In light of the substantial capital investment Columbia has made and the large capital investments that will be made through the end of 2022, Columbia is filing this base rate case using the Fully Projected Future Test Year ("FPFTY") authorized by 66 Pa. C.S. §315 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 when the Distribution System Improvement Charge ("DSIC") is available?

A. Columbia's revenue deficiency is driven by the large capital investment that it continues to make in modernizing its distribution system. 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 proceeding exceeds the current 5% cap for a DSIC surcharge. I would note that in 2016, Columbia requested Commission approval to increase the cap on DSIC surcharges to 10%, but the requested waiver was denied.

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 base rate case and Columbia's existing and planned capital and O&M programs, Columbia will experience a revenue deficiency of approximately $98.3 million, as detailed and supported in testimony of Company witness Miller (Columbia Statement No. 4). This revenue deficiency is driven primarily by substantial capital investments Columbia has made, and continues to make, in its system. As detailed in Company witness Brumley's testimony (Columbia Statement No. 7), since Columbia started its accelerated pipeline replacement program in 2007, Columbia has replaced 6,078,654 feet (over 1,150 miles) of cast iron and bare steel pipe. In addition, during that time period Columbia replaced additional pipe that needed to be replaced, but which is not presently counted as "priority pipe".

Q. Has Columbia considered the impact of a rate increase on customers?

A. The Company realizes that rate increases will always have an impact on customers; however, in light of the large and growing capital program which is necessary to retire and replace aging infrastructure, a rate increase is unavoidable. As explained in Company witness Davis' testimony (Columbia Statement No. 13), the Company has taken - and will continue to take – specific measures to assist those financially insecure customers, especially those customers who find themselves impacted by COVID-19. In addition to the safety and reliability benefits provided by the Company's large scale pipeline replacement program, the Company believes that maintaining and growing its infrastructure modernization program provides the ancillary benefit of energizing the local economies through the wages paid to the skilled labor necessary to complete the work.

b. <u>Other Objectives</u>

Q. Does Columbia have other objectives in this case?

A. Yes. Additional objectives in this proceeding are as follows:

Continued Funding of Enhanced Safety Measures: The Company continues to focus its efforts and resources on the top risks to the Company's systems, and is expanding focus in several critical areas to maintain and enhance its operational capabilities. These efforts are supported by NiSource's continued implementation of Safety Management System ("SMS") across its six-state footprint. NiSource's SMS focuses on leveraging employees who are performing the work to identify risks so that the risks can be mitigated. In addition, Columbia's SMS provides a proven structure to continually assess and improve processes and procedures to keep employees, contractors, customers, and the public safe. As Columbia's SMS identifies risks, the Company uses an objective risk-based approach to prioritize the mitigation efforts which need to be undertaken as well as the sequencing of those efforts to provide the highest risk reduction at the best possible cost to the customer.

In the Company's most recent base rate case, the Commission approved a number of SMS driven safety initiatives that were narrowly focused, but will enhance safety for Columbia, its employees, and for the communities we serve. Specifically, the Commission approved the Company's request to: (1) accelerate Columbia's staged approach of identifying and remediating cross bores; (2) accelerate the Company's expanded field assembled riser replacement program to include customer owned facilities; (3) hire fulltime employees to accelerate Columbia's legacy service line record enhancement program to correct inaccurate and/or incomplete data within legacy records; and (4) employ the Picarro analytics system to enhance the Company's process to refine how leak repairs and replacements are prioritized on the natural gas distribution system.

As outlined in the testimony of Columbia witness Anstead (Columbia Statement No. 14), as a result of Columbia's SMS, the Company is implementing two additional programs to improve safety and reduce risk. The first program is the System Pressure Visibility Program, which includes installing digital pressure recording telemetry equipment at natural gas pressure regulator stations across the Columbia operating territory. The new digital devices will transmit real time pressure data to Gas Control Supervisory Control and Data Acquisition (SCADA) systems where pressures and alarms will be monitored by Gas Control personnel and computer systems 24/7. This new technology will improve operational safety through immediate awareness of operating pressures and abnormal operating pressure conditions and ensure more reliable and accurate operating pressure data capture that cannot be matched by traditional analog paper pressure charts primarily due to fewer mechanical parts.

In addition to the System Pressure Visibility, as a result of Columbia's SMS the Company is also updating its red tag procedures applicable to customer-owned appliances to retain more knowledge of the issues with customer owned appliances and to provide inspections at the request of the customer to ensure the gas line downstream from red tagged appliances remains safe.

Establishment of a Revenue Normalization Adjustment ("RNA") Mechanism: Columbia proposes to implement an RNA to be used in conjunction with its Weather Normalization Adjustment ("WNA"). Through this proceeding, the Company proposes to establish a benchmark revenue level, regardless of changes in customers' actual usage level. Excess collections above the benchmark revenue level would be refunded to customers and amounts below the benchmark level would be recouped by the Company. Company witness Notestone will discuss the proposed RNA further in Columbia Statement No. 11.

Establishment of a Federal Tax Reform Adjustment ("FTRA") rider: Columbia proposes the FTRA so that the Company will have a Commission approved rider in place to address any changes to the Federal income tax rate should the rate change from the current rate of 21%. Company witness Harding will discuss the proposed FTRA in Columbia Statement No. 10.

Q. Does the Company have any other ongoing initiatives?

A. Yes. NiSource Next is an enterprise-wide initiative focused on leveraging our company's scale, driving efficiencies, improving our cost structure and capabilities, and enhancing our ongoing commitment to safety. The NiSource Next initiative will focus on the following outcomes:

- An unwavering commitment to safety leadership through our ongoing SMS journey.
- Fostering innovation within teams to rethink outdated processes and drive efficiencies.
- Leveraging technology to make meaningful connections to customers and enhance service levels.
- Streamlining cost structures to drive efficiencies across the organization.
- Standardizing operations management supported by modern technology for improved speed and reliability.

This program of work is already underway and has deepened our focus on driving O&M cost savings and transforming our operations to ensure we are well-positioned to deliver on our commitments to operational excellence and customer value. Safety is the first priority of our NiSource Next work and it will build upon the successes we have had in our ongoing SMS journey.

Q. Please describe NiSource Next.

A. NiSource Next is a comprehensive, multi-year program designed to deliver long-term, sustainable capability enhancements and cost efficiency improvements that reflect NiSource's commitment to safety, risk mitigation and customer service. NiSource Next is structured to leverage our scale, use technology, define clear roles and accountability with our leaders and employees and standardize our processes to create an organization focused on operational rigor and continuous improvement.

<u>Future Infrastructure Replacement</u>

Q. What are the Company's future plans for infrastructure replacement?

A. The Company intends to continue replacement of prone to fail pipe at an accelerated pace in order to retire its remaining bare steel and cast iron facilities as soon as possible. In addition, as Columbia's infrastructure replacement program has been operating for 14 years, the program is now mature, and Columbia has made considerable progress in replacing the cast iron and bare steel on its system. While our efforts in this regard are not complete, we are at juncture where risks beyond bare steel and cast iron now need to be considered. First generation plastic (i.e. plastic pipe installed before pre-1982) and pre-1971 coated steel pipe are examples of such risks. When these types of pipe are identified in connection with the Company's primary efforts to replace cast iron and bare steel, these types of pipe are included in the project in order to address that risk at the same time the cast iron or bare steel is being replaced. While both pre-1971 and first generation plastic pipe are being replaced and are helping to reduce leakage and risks on the Company's system, neither of these two categories of pipe are included in our reports that focus on "Priority Pipe", even though these two categories of pipe are considered "Replacement Pipe" in the budgets and footages in the Company's filings and reports. The Company will therefore be adding pre 1971 coated steel pipe as well as first generation plastic pipe to the category of "priority pipe" in the next Long Term Infrastructure Improvement Plan. As Columbia's infrastructure program continues to mature, the Company will remain focused on implementing an efficient pipe replacement program. Doing so will enable the Company to maximize the capital spend to remove priority pipe. For example, Columbia will include replacing short, non-contiguous segments of plastic pipe that are encountered when analysis shows that it is more cost effective to replace rather than to reuse these segments of pipe while replacing priority pipe.

In addition, as Columbia' SMS and DIMP programs continue to mature and identify risks that need to be considered and addressed, Columbia may identify additional risks that warrant "priority" replacement. Figure 1 below is an excerpt from the Company's response to Standard Data Request GAS-ROR-014. I note that Columbia's ability to increase its capital investment and maintain these accelerated levels of investment is a direct result of Act 11's impact on reducing the regulatory lag that was formerly associated with utility ratemaking in Pennsylvania.

Figure 1

Budgeted Capital Expenditures					
Class	**2021**	**2022**	**2023**	**2024**	**2025**
Growth	$42,952	$42,676	$41,220	$44,893	$48,904
Betterment	$42,615	$8,500	$10,700	$8,500	$5,452
Public Improvement	$9,497	$6,000	$7,500	$7,939	$7,449
Replacement	$260,838	$289,108	$339,809	$348,704	$366,628
Support Services	$2,750	$3,250	$2,700	$2,250	$2,344
Total Gross Capital	**$358,652**	**$349,534**	**$401,928**	**$412,286**	**$430,777**

Q. What are the drivers for Columbia to continue investment in replacing aging infrastructure?

A. As shown in Figure 2 below, in terms of miles, Columbia's distribution system is the third largest in Pennsylvania.

Figure 2

Pennsylvania LDCs – Pipeline Mileage

NGDC	Miles of Pipe (2019)
Columbia Gas	7,656.40
PGW	3,040.72
PECO	6,928.30
UGI[1]	12,028.00
Peoples[2]	13,081.30
National Fuel	4,842.87

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 16% of Columbia's

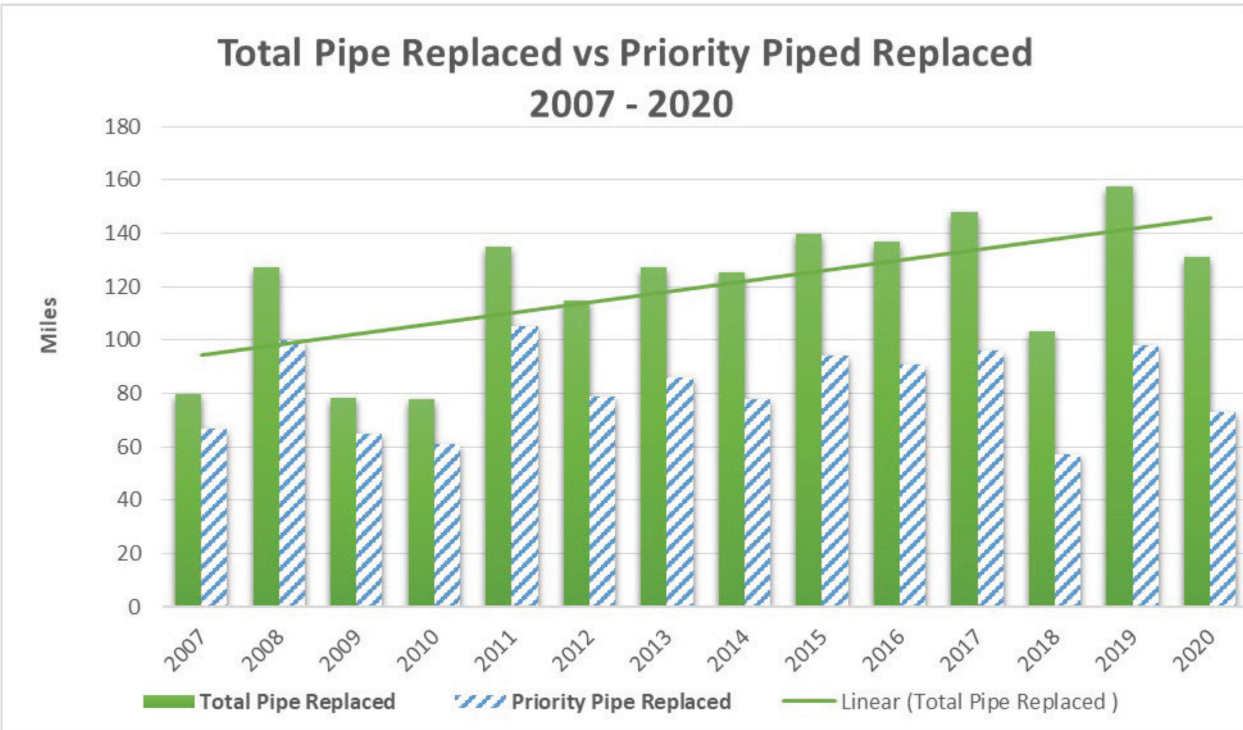
[1] All companies/ divisions combined.
[2] All companies/ divisions combined.

total inventory of pipe is either bare steel or cast iron, approximately 8% is pre-1982 plastic, and approximately 16% is pre-1971 coated pipe, which are nearing the end of their useful life. When the latter two types of pipe border cast iron or bare steel, the Company will include them in the replacement project in order to reduce that risk now while the community is disrupted due to the replacement work. Further, gas prices continue to remain low in Pennsylvania and continuing to invest in pipeline replacement while gas prices are low will aid in mitigating the impact on the customer's total bill.

Q. What is the Company's history of retired bare steel and cast iron pipe?

A. See Figure 3 below for the Company's history of infrastructure replacement compared to total pipe replaced since 2007, which was the first year the Company began replacing pipe at an accelerated rate.

Figure 3



Q. Discuss the Company's infrastructure replacement program levels over the past few years.

A. As Figure 3 above indicates, following a decrease in 2018, the Company resumed its normal performance levels by replacing 98 miles of bare steel and cast iron in 2019. Unquestionably, 2020 posed new challenges, but, despite the impact of COVID-19 pandemic on our operations, as described in Columbia witness Brumley's testimony, Columbia was able to successfully complete its infrastructure replacement program in 2020 by replacing 73 miles of cast iron and bare steel and 10 miles of pre-1982 plastic and 18 miles of pre-1971 coated steel.

Q. As your replacement program has progressed, how is Columbia enhancing its approach to infrastructure replacement?

A. Through our own experiences beginning in 2007 when we began to accelerate infrastructure replacement, and through the experiences learned from other Columbia companies across the NiSource footprint, the Company is expanding the focus of risk reduction beyond the replacement of aging infrastructure.

Q. How has the Company expanded risk identification?

A. The Company has established SMS pursuant to American Petroleum Institute Recommended Practice (or "RP") 1173. RP-1173 provides guidance to pipeline operators for developing and maintaining a pipeline safety management system, and is intended to augment existing practices while not duplicating any other requirements.

Q. How will SMS impact the Company's infrastructure replacement plan going forward?

A. Today, replacement of bare steel and cast iron mains and services are the priorities that drive infrastructure modernization. SMS is expanding the classes of priorities through identification of risk reduction, in addition to bare steel and cast iron.

Q. Can you provide an example of how SMS has impacted the Company's infrastructure replacement program?

A. In addition to the 73 miles of bare steel and cast iron pipe replaced in 2020, the Company replaced an additional 28 miles of first generation plastic pipe installed prior to 1982 and pre-1971 coated steel. As Company witnesses Anstead and Brumley discuss in their testimonies, first generation plastic pipe, typically installed between 1970 and 1981 in most distribution systems, is more brittle than today's material composition of plastic pipe and has demonstrated itself to be prone to stress propagation cracking under some circumstances. Likewise, pre-1971 coated steel pipe needs to be prioritized for replacement as federal standards requiring operators to cathodically protect and maintain all new steel piping installations were not adopted until 1971. Beginning in the 1950s and into the 1960s, coated steel pipe was installed in gas distribution systems as a means of fending off corrosion. However, in those early years the industry lacked standards for cathodic protection and coating material was not as effective as today's materials, and hence, pre-1971 coated steel pipe has been identified for accelerated replacement. The Company has identified risks regarding the failure of both pre-1982 plastic pipe and pre-1971 coated steel pipe and replaces them as part of our cast iron and bare steel projects when they are found next to cast iron and bare steel. As we move forward and these facilities continue to age and the Company continues to reduce the inventory of cast iron and bare steel further, the Company will prioritize replacement of pre-1982 plastic and pre-1971 steel in stand-alone situations. Consequently, Columbia will be incorporating pre-1982 plastic and pre-

1971 steel pipe as stand-alone categories in its next update to its Long Term Infrastructure Improvement Plan.

Q. How is SMS different than other pipeline safety programs and initiatives? (DIMP, TIMP, Damage Prevention, Public Awareness, Infrastructure modernization, etc.)?

A. SMS is a proactive and systematic and all-encompassing approach to managing safety, including the structures, policies and procedures an organization uses to direct and control activities. The API has developed RP 1173 Pipeline Safety Management Systems to provide an SMS tailored for pipeline operators. While leadership commitment is critical to a successful SMS, the identification of risk happens at all levels of an organization.

SMS builds upon pipeline safety programs and initiatives, such as DIMP and TIMP. Indeed, a Pipeline SMS places particular emphasis on proactive thinking of what can go wrong in a systematic manner, clarifying safety responsibilities throughout the pipeline operator's organization (including contractor support), the important role of top management and leadership at all levels, encouraging the non-punitive reporting of and response to safety concerns, and providing safety assurance by regularly evaluating operations to identify and address risks. These factors, plus a strong safety culture, work together to make safety programs and processes more effective, comprehensive, and integrated.

While other pipeline safety programs and initiatives, such as DIMP, TIMP, Damage Prevention, Public Awareness and Infrastructure Modernization, address specific areas of risk, these programs in large part rely on previously gathered data and react to that data. SMS is a much more proactive, systematic and holistic approach to risk management when compared to DIMP, TIMP, Public Awareness and Infrastructure Replacement programs. An SMS encompasses, supplements and supports all other safety programs and initiatives, while providing all employees with the support and resources to own risk management.

Q. How does SMS benefit Columbia's customers?

A. It enhances Columbia's risk prioritization and modeling, and strengthens and formalizes our continuous improvement processes, which helps us provide the safest possible service at the best cost to the customer These enhancements will continue to improve the integration of all pipeline safety initiatives across the Company's organization. Through SMS we are increasing our rigor, and continuously learning and improving so we can identify risks and take actions to keep our employees, contractors, customers and communities safe. SMS uses the following building blocks: (1) culture – as all employees and contractors are empowered to report risks; (2) process safety – layers of protection for safe work with a focus on enhanced consistent standards and processes); and (3) asset management – accountability to effectively evaluate, prioritize, and mitigate identified risks.

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 FPFTY ending December 31, 2022, pro forma and adjusted for known and measurable changes. Columbia then compared the costs determined for the FPFTY to the revenues at present rates calculated for the FPFTY. 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 address 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 in the FPFTY. The proposed rates have been developed to address this deficiency.

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 5.18% in the FPFTY 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 7.88%. Company witness Moul (Columbia Statement No. 8) demonstrates that Columbia should be granted an opportunity to earn a 10.95% rate of return on common equity.

IV. MANAGEMENT EFFECTIVENESS

Q. Is the Company seeking a rate of return adjustment for management effectiveness in this proceeding?

A. No. While Columbia believes its performance would otherwise warrant such an upward adjustment, Columbia has opted not to seek an adjustment in this proceeding in light of the COVID-19 pandemic. The Company, and its employees, continue to perform at a high level to the benefit to our customers and the communities we serve.

Q. If Columbia were seeking to adjust the Company's requested rate of return for management effectiveness, what evidence would the Company offer in support?

A. Columbia continues to maintain high levels of customer service, both in back office operations and in field operations. I will discuss each item individually. Field operations and customer service will be discussed in the operations section of my testimony.

Q. How has Columbia performed relative to its peers from a Management

Audit perspective?

A. In addition to Columbia's aggressive pipeline replacement program detailed in the testimony of Company witness Brumley, which demonstrates the effectiveness of Columbia's management and its concern for safety and excellence in customer service, Columbia has analyzed the most recent Management and Operations Audit reports from the Commission's website for Columbia, Peoples Natural Gas Company, Philadelphia Gas Works, UGI, National Fuel 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. Columbia 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 8, below.

Figure 8
Summary of Most Recent
Commission Management and Operations Audit Results

Standard	CPA	Peoples*	PGW	UGI	NFG	PECO
Meets Expected Performance	36%	27%	6%	0%	55%	20%
Minor Improvement Necessary	45%	27%	44%	58%	45%	47%
Moderate Improvement Necessary	18%	27%	50%	33%	0%	33%
Significant Improvement Necessary	0%	18%	0%	8%	0%	0%
Major Improvement Necessary	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%

* People's represents People's Natural Gas, the former Equitable Gas and People's TWP

As Figure 8 illustrates, Columbia achieved the "Meets Expected Performance" ranking category in 36% of the categories evaluated by the auditors, with only one peer, NFG, scoring higher than Columbia. Also, Columbia was one of four gas companies that did not receive any ranking of "Significant Improvement Necessary". A review of the information in Figure 8 and Exhibit MK-1 shows that, based upon Commission audits, Columbia's performance exceeds that of its peers.

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 Report and Evaluation ("UCARE") for 2019. The overall information contained in the Activities 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. As shown in Figure 9, below, overall, Columbia's 2019 performance, as reflected in the UCARE report with regard to the seven major natural gas companies, is among the best in most categories in the gas industry. In the measure of Residential Consumer Complaints, Columbia had the lowest consumer complaint rate of 0.34 per 1,000 residential customers in the gas industry, as noted in Figure 9 below. Columbia's consumer complaint rate was also better than any of the seven major natural gas companies, which averages 0.91.

Figure 9

2019 Residential Consumer Complaint Rates/
Justified Consumer Complaint Rates
Major Natural Gas Distribution Companies

Utility	Consumer Complaint Rate	Justified Consumer Complaint Rate
Columbia	0.34	0.01
NFG	0.49	0.05
Peoples	0.68	0.01
Peoples-Equitable	0.66	0.04
PGW	1.92	0.16*
UGI South	0.81	0.09
UGI North	1.50	0.16
Average	**0.91**	**0.07**

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

Per Figure 10 below, Columbia's Justified Consumer Rate per 1,000 residential customers is at 0.01, which is the same as 2017 and 2018. Columbia's Justified Consumer Rate is better than the natural gas utility average rate of 0.07. Columbia's rate has consistently remained one of the lowest of all natural gas companies, at a rate of 0.01 for years 2017-2019. I am especially proud of these numbers in light of the substantial disruption that our pipeline replacement can have on customers and their communities. Nobody likes to have their streets, sidewalks and lawns dug up; however, our team provides quality work and respectful interactions with customers and this is reflected in the low complaint rate. As a result, our customers are satisfied even though we caused them and their communities disruption from our construction activities.

Figure 10

2017-19 Justified Residential Consumer Complaint Rates
Major Natural Gas Distribution Companies

Utility	2017	2018	2019
Columbia	0.01	0.01	0.01
NFG	0.04	0.05	0.05
Peoples	0.00	0.02	0.01
Peoples-Equitable	0.01	0.04	0.04
PGW*	0.14	0.15	0.16
UGI South	0.03	0.14	0.09
UGI North	0.04	0.29	0.16
Average	**0.04**	**0.10**	**0.07**

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

Columbia's Payment Arrangement Request ("PAR") rate was 1.17 in 2019 and the Justified PAR rate was 0.03. Columbia had the lowest score amongst all seven Pennsylvania gas utility companies, as shown in Figure 11 below.

Figure 11

2019 Residential Payment Arrangement Request (PAR) Rates/ Justified PAR Rates
Major Natural Gas Distribution Companies

Utility	PAR Rate	Justified PAR Rate
Columbia	1.17	0.03
NFG	3.10	0.24
Peoples	2.59	0.19*
Peoples-Equitable	2.76	0.20
PGW	9.87	1.06*
UGI South	6.35	0.75*
UGI North	9.58	1.03*
Average	**5.06**	**0.50**

* Based on a probability sample of cases.

In the measure of Commission Infractions, Columbia had an infraction rate per 1,000 residential customers of 0.00 in 2019, which is the lowest of all seven major natural gas companies. Figure 12, below, is illustrative.

Figure 12

Commission Infraction Rates
Major Natural Gas Distribution Companies

Utility	2017	2018	2019
Columbia	0.00	0.01	0.00
NFG	0.03	0.05	0.07
Peoples	0.00	0.03	0.01
Peoples-Equitable	0.00	0.02	0.03
PGW	0.12	0.17	0.19
UGI South	0.02	0.16	0.14
UGI North	0.06	0.34	0.24

Q. Can you provide an overview of Columbia's 2019 Quality of Service Performance Report?

A. Yes, Columbia's "Quality of Service Performance Report," which was filed on January 31, 2021, has 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 reports three separate measures of telephone access: 1) average busy out rate; 2) call abandonment rate, and 3) percent of calls answered within 30 seconds. Columbia was pleased with the results of its 2019 Quality of Service Performance Report.

Columbia continues to hold a firm 0% busy out rate for the last 12 years, while Calls Answered within 30 seconds is at 86%, up from 83% in 2019. Columbia experienced an abandonment rate of 2.04%. Although the abandonment rate was higher than 2019's of 1.94%, it is lower than 2017's abandonment rate of 2.06%. Columbia's abandonment rate is tied for the lowest in the gas industry.

Columbia continues to recruit via NiSource job postings digital print advertising, and social media postings. The Company also continues to focus on retention of current call center employees and has partnered with an outside vendor focused on employee engagement and retention. Through collaborative efforts with our vendor, we are better able to interactively diagnose and address workplace issues, while making continual improvements. The Company is currently working on solutions of how to best incorporate this system with our current at home work force. As a result of COVID and transitioning to remote work, Columbia has incorporated virtual screening, testing, and interviewing into our hiring practices, which provides for greater flexibility for the Company, and for candidates. In addition, the Company has expanded the geographic recruiting search up to 80 miles from the Smithfield, Pennsylvania customer care center. This modification also includes strategic diversity recruitment efforts with community based organization such as Pittsburgh Community Services, Inc. (PCSI), Pennsylvania Career Link, community church leaders, Fayette County NAACP, and the African American Chamber of Commerce of Western Pennsylvania. The effectiveness of virtual recruiting has helped to widen our talent selection pool. Finally, Columbia has also implemented virtual new hire training to onboard new customer service representatives.

Residential and Small Commercial Billing Data:

For the tenth consecutive year, Columbia did not have any deferred billings for its residential or small commercial customers. A strong emphasis on reducing occurrences of deferred bills by Columbia's Billing Exceptions Group continues to aid in this success, and this group continues to exhibit a strong effort on the prompt follow up of billing abnormalities.

Columbia printed and mailed 4 million bills to customers in 2020. In addition, over 1.2 million paperless bills were issued to customers. In July 2020 Columbia enhanced its paperless billing enrollment process to make it easier for customers to enroll. This enhancement has contributed an increase in approximately 200,000 additional paperless bills issued over 2019's number of 1 million.

Approximately 4.5 million payments were posted to customer accounts; of those, 67% were electronic payments.

2. Meter Reading:

In 2020, Columbia obtained over 5.3 million meter readings with 99.92% of meters read on the scheduled meter reading date. Columbia experienced an increase in the number of meters not read monthly in accordance with 56.12 (4)(ii). For 2019, the Company averaged only two (2) meters read outside the 6-month time frame compared to an average of 21 meters not read in 2020. Normally, meter reads are picked up through Columbia's Mobile Collecting Device located in the vehicle. If any reads are not able to be transmitted or received by the Mobile Collector when driving by customer locations, the meter reader may walk up to the location and often times obtain the meter read by way of the handheld device, which can occur if the meter is located inside the home as well. If the Meter Reader has access to a meter, a visual read can also be obtained. Due to Covid-19 and the Company's policy not to enter the customer's home unless there is a safety issue, the number of unread meters did increase. In 2019, the Company remained at only one (1) meter being read outside the 12-month interval to be in compliance with 56.12 (4)(iii). Again, for 2020, the number of meters not read under 56.12 (4) (iii) increased in the later months of 2020 for the same reason as explained above.

3. <u>Customer Satisfaction:</u>

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

A. Columbia uses a variety of methods to gather customer feedback. 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 J.D. Power, MSR and Metrix Matrix. Columbia participates in the J.D. Power Gas Residential Customer syndicated survey, utilizes the MSR group to conduct a post-transaction satisfaction study and participates in the Metrix Matrix study mandated by the Commission. Columbia also relies on an online residential customer panel to help the Company incorporate customer feedback into improving the customer experience.

Q. Can you share the results of these surveys?

A. Based on the results of the MSR survey, Columbia provided high quality service to its customers in 2020. In 2020, Columbia's "First Contact Resolution" rate was 92.46%. This statistic indicates the success our call center has had in satisfying customers the first time they contact the Company. Figure 13, below, gives more detail on the service results Columbia achieved in this area in 2020

Figure 13

Phone Rep Performance	
	YE 2020
Overall satisfaction	94.15%
Put on hold after speaking with a rep	17.17%
Rep explained reason for hold	91.68%
Being courteous and professional	94.59%
Treated as a respected customer	94.58%
Showing concern for the situation	91.32%
Displaying knowledge in job	91.11%
Adequately answering questions	91.36%
How well rep listened to customer	93.37%
Having authority to make decisions	90.42%
Working quickly and efficiently	90.98%
Clarity of speech, speed, tone, and volume	94.33%
First contact resolution	92.46%

CPA Automated Phone Service	
	YE 2020
Overall satisfaction	81.85%
Offering choices that helped get directly to the information wanted	77.63%
Ease of navigating prompts	77.04%
Ease of getting connected to live representative	77.11%
Number of steps required to complete the transaction	72.50%
IVR first contact resolution	76.35%

Q. How well did Columbia perform on field service ratings?

A. As reflected in Figure 14 below, MSR results for Columbia's Field Service Representatives easily met the Company's 90%+ satisfaction threshold goal. The following chart demonstrates that customers are satisfied with the level of service provided by Columbia employees working at their home or on their property.

Figure 14

CPA Field Visit Scheduling	
	YE 2020
Willing to accommodate needs	94.97%
Told when work would take place	94.32%
Arrived on time	95.80%
Total time to resolve	95.65%
CPA Field Work Crew Performance Ratings	
	YE 2020
Overall satisfaction with performance	96.19%
Courteous and professional	97.98%
Displayed skill and knowledge	97.82%
Explained work being performed	98.24%
Adequately answered questions	97.23%
Aware of service performed	94.15%
Worked quickly and efficiently	98.26%
Being respectful of your property	97.54%
Left work property as found before work began	98.70%
Work crew identified themselves	98.14%
Work was completed by the work crew	91.70%
Satisfied request on the first visit	91.31%

Q. How did Columbia perform in the 2020 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia achieved an overall Customer Satisfaction Index ("CSI") score of 765 in the annual J.D. Power survey of mid-sized eastern natural gas utilities, ending 2020 in second place. This is an increase of 20 points over the Company's 2019 final survey result of 745. The Company outperformed the mid-sized eastern utility average of 734 by 31 CSI points and gained in all categories. Columbia's overall industry rank also improved by 14 positions.

In addition, Columbia Gas beat the mid-sized eastern utility averages in all seven categories and had the top mid-sized eastern ranking in the Safety & Reliability, Customer Service, and Billing & Payment categories.

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

A. Over the past 15 years, Columbia has been successful in implementing the Commission's 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 4.07% in 2005 to 2.06% in 2019. It also reduced its net write-off for the same period from 2.79% to 1.22%.

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 2019 Universal Service and Collections Report, as seen below, Columbia had the most affordable Customer Assistance Program ("CAP") in the Commonwealth. In 2019, Columbia's monthly average CAP bill was $52.00. This was the lowest bill amount of all gas and electric utilities in the state during 2019. Further, as per below, Columbia CAP has the lowest default rates, in each poverty level, than all other gas utilities.

		2019		
Utility	**Average Monthly CAP Bill**	**0 - 50% of FPIG**	**51% - 100% of FPIG**	**101% to 150% of FPIG**
Columbia	$52	19.1%	15.8%	18.5%
NFG	$59	24.4%	24.4%	24.4%
PECO- Gas	$64	28.0%	20.1%	25.4%
Peoples	$77	24.9%	16.1%	34.8%
Peoples/Equitable	$75	23.7%	17.5%	54.7%
PGW	$115	32.8%	16.7%	52.1%
UGI South	$67	31.4%	28.1%	42.0%
UGI North	$72	31.3%	29.6%	41.4%
Total Industry Average	$73	27.0%	21.0%	36.7%

Columbia's most recent independent Universal Services Evaluation, completed in 2017, found that Columbia's Universal Services programs were well-managed, with attention to detail, quality control and efficiency. Key highlights included in the report are as follows:

- Columbia's CAP administrative costs are among the lowest as compared to other Pennsylvania natural gas distribution companies. Columbia's CAP is well-managed with adequate controls put into place for limiting program costs.
- The Company has taken extraordinary steps in ensuring quality and consistency with its Low Income Usage Reduction Program ("LIURP") implementation. Columbia's LIURP process and procedures are well-written and easily understood.
- The Vision database is exceptional in tracking LIURP workflow and is regarded as a useful tool by both the internal and external LIURP teams. The data base, adopted in April of 2016, is a contact management, invoicing and reporting data base for customers.

Columbia's LIURP program is the second largest gas program in the state. Columbia's proposal to offer a LIURP pilot program to address the increasing number of jobs deferred for health or safety issues was recently approved in Docket M-2018-2645401. Through this pilot, Columbia will earmark a maximum of $200,000 to be used to remediate those typical obstacles to providing weatherization measures such as the existence of knob and tube wiring and moisture issues, both of which prevent insulation from being installed. The Company is currently seeking eligible customers for this program.

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

A. Columbia has a continued focus on providing a simple and seamless experience for customers, and will continue its focus to work across all business lines to further strengthen and enhance relationships with its customers by proactively resolving their concerns and making it easier to conduct business with us. Examples of enhancements to improve customer interaction in 2020 includes:

- Implemented the ability for customers to make bill payments via PayPal, PayPal Credit, Amazon Pay, and Venmo.
- Enhancements to Paperless Billing enrollment process to make it easier for to customers to enroll on the website, during online account registration, and on the phone with a Customer Service Representative.
- Launched a new Bill and Payment Alerts program so customers can receive bill reminders and payment confirmations via email or text message.
- Launched a new usage information page to provide customers with more information about their account's energy usage and compare month/month gas usage.

- Various usability enhancements to allow customers to more easily navigate our website platform on mobile devices.
- Ensured pre-login content on Columbia's website was able to be translated into the following languages: Chinese, French, German, Japanese, Korean, Portuguese, Spanish.
- Provided customers frequent communications and updated website content with relevant safety messaging and protocols for COVID-19.
- Implementing a new Interactive Voice Recognition Unit at the Customer Care Center which will enable customers to interact more easily using natural language commands.

Q. Besides customer service initiatives, is Columbia taking any effort to improve customer, employee, and system safety?

A. Yes, the Company along with the other operating Companies in NiSource have adopted a Safety Plan for 2021. This multifaceted plan will coordinate with and leverage certain aspects of the "NiSource Next" initiative that is described earlier in my testimony. The Safety Plan will include new processes, training, tools and support all of which are designed to improve safety and eliminate high-consequence events. Some of the new processes being implemented under the Safety Plain include:

- "Daily Acknowledgment Process", under which field employees must acknowledge - before they do work each day - that they have completed a pre-job brief to identify risk and hazards associated with the work they are going to perform; that they have all necessary operator qualifications to perform the work they are going to do; and that they are familiar with the applicable gas standards that apply to the work they are going to do. The Daily Acknowledgement serves as a daily reminder and checklist for employees, and employees are expected to stop work if they are not familiar with the gas standards governing the work that needs to be performed or they do not have the appropriate operator qualification.

- "Critical Process Review", under which employees will review and verify their understanding of their comprehension of the policy and procedures, operational notices, and gas standards associated with the most critical processes employees perform every day, including but not limited to: purging gas mains and services, pressure configuration control; work zone setup; locating and marking underground facilities; tie-ins; and customer relights. This Critical Process Review started at the beginning of 2021 and will continue through the middle of the year.
- "Quality Control Audit Plan/Quality Assurance Audit Plan" under which a field quality control audit plan and a quality assurance audit plan will be created based on the selected Critical Processes. The plans will include metrics, reporting and Quality Management System process owners.

- "Process Safety Reviews" under which we will provide resources and plans to perform process safety reviews for all selected critical processes in order to verify the ability to "fail safely" and/or whether we need to add additional layers of protection.

In addition to these new processes, the Company is providing additional support to employees to further promote safe behavior and results. Some of the support for employees under the new Safety Plan includes:

- "Supporting Field Materials" in which we will review, refresh and supplement materials used by employees to support the critical processes, such as Policies and Procedures, Operational Notices, Standard Operating Procedures (SOPs), special instructions and checklists.
- "Refresher Training", in which we will develop, plan and implement refresher training for applicable employees on all critical operations processes.
- "Performance Support Tool Utilization" in which we will provide additional support on the use of the electronic "Performance Support Tool" application which contains all of the necessary policies and procedures, gas standards, operation notices and other important information pertaining to the critical processes and other gas standards. Our goal is to get the right information to the employee at the right time so

that the employee has the information and confidence necessary to do the job right.

The 2021 Safety Plan was carefully designed to target those critical processes which if not precisely followed could result in high consequence events. Our goal is to eliminate those high-consequence events by providing clear processes, training and support to our employees so they have the knowledge, skill and confidence to perform these events flawlessly and repeatedly.

Q. How does Columbia support the communities it serves?

A. Columbia is dedicated to investing in the communities we serve, and to helping enhance quality of life for our customers, as well as our employees. It is important to ensure that individuals and families within the communities we serve have what they need to thrive. Each year, we provide funding to organizations that assist people in meeting their basic needs, such as food, clothing, and shelter. By partnering with community leaders and state, regional, and local economic development organizations, Columbia is working to attract new businesses and support the expansion of existing businesses, while helping to create more jobs across the area. Contributions made to the community by Columbia and its employees in 2020 include the following:

- United Way: Columbia employees pledge over $117,000 of their personal income to the United Way, in support of education, financial stability and community health.

- Community Donations: Columbia also donated[3] to approximately 120 different non-profit organizations throughout the 26-county and 450 community service area, where we deliver natural gas. Donations supported safety, economic and workforce development, environmental stewardship, STEM & energy education, basic needs and hardship assistance. We also provided $18,000 for the purchase of combination carbon monoxide and smoke detectors for a dozen communities throughout our service area, for which a portion of those funds went to first responders.
- Non-Profit Organizations: Columbia donated $430,000 to non-profit organizations, to help support and improve the quality of life for our customers and fellow community members. Examples of donations made in 2020 are as follows:
- American Red Cross: Columbia made a $110,000 donation to the American Red Cross in support emergency first response as a result of COVID-19
- Dollar Energy Fund: We also fundraised and increased our support to the non-profit, Dollar Energy Fund, providing utility assistance to income-eligible families experiencing hardship.
- Food Banks: Supporting basic needs, during a time when so many families

[3] Donations made through the NiSource Charitable Foundation. Charitable contributions are not funded by customers though utility service rates. Charitable contributions are primarily funded by shareholders as a core part of the Company's commitment to support the communities and customers it serves.

relied on essential food donations, we donated thousands of dollars to local food banks.

- First Responder Training: When health and safety mattered most, we partnered with the Northeast Gas Association to provide a free, computer-based first responder natural gas safety training program. Through the program, we trained 117 local first responders on how to respond safely to natural gas emergencies

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

A. In previous base rate proceedings, Columbia has proposed programs to expand the availability of natural gas in Pennsylvania, as follows:

- **Main and Service Extension and House Piping Credit:** In the Company's 2015 Rate Case, Docket No. R-2015-2468056, the Commission authorized three new business proposals 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 for residential customers in the geographic areas where the Company owns the service line; and, the house piping reimbursement program, which enables new residential customers to receive a limited reimbursement for gas piping in defined circumstances.
- **Large Customer Incentive Program:** In the Company's 2016 Rate Case, Docket No. R-2016-2529660, the Commission authorized Columbia's Large

Customer Incentive program. This program is available to applicants who are projected to use more than 64,400 therms annually and who are required to pay a deposit under the Company's main extension policy. The program allows for the customer to pay the deposit for the uneconomic portion of the expansion cost over a period of time, up to ten years. For customers who desire a repayment period over ten years, an up-front payment of 30% of the deposit would be required. In addition to the programs to expand natural gas availability noted above, Columbia's Sales and Marketing team is working with economic development agencies throughout our service territory to identify grants that may be available for new business expansion to help offset the costs of extending mains. The Pipeline Investment Program ("PIPE"), established by Governor Wolf in 2016, provides grants to construct natural gas distribution lines to business parks and existing manufacturing and industrial enterprises, which will result in the creation of new economic base jobs in the Commonwealth, while providing access to natural gas for residents. Applicants who are eligible for PIPE funding include businesses, economic development organizations, hospitals, municipalities, and school districts.

To date, Columbia has been an active participant in helping SEDA-COG Natural Gas Cooperative, Inc. obtain approval for a $1 million PIPE grant for the construction of a point of delivery ("POD") station located in Centre Hall Borough, part of Columbia's service territory. As a result of the installation of the POD, approximately 20,000 feet of gas pipeline was constructed through the currently unserved town of Centre Hall, to provide natural gas service to over 100 new customers, including residential and small commercial customers. The savings and efficiencies resulting from this project will allow Hanover Foods Corporation, a local business, to retain its current workforce of 150 full-time jobs. Construction was completed in June of 2020.

In addition, Columbia has worked with Glenn O. Hawbaker, Inc. to utilize their $1,000,000 PIPE grant to provide natural gas to their asphalt manufacturing plant as well as provide gas service to the unserved town of Barkeyville, Pennsylvania. The 35,000 foot pipeline extension is completed and is expected to provide service to at least 26 residential customers along the route.

Columbia will continue to explore opportunities with potential customers and economic development agencies to identify potential projects that may benefit from the PIPE grant program to bring natural gas to their facilities, and the communities in which they operate and we serve.

V. INTRODUCTION OF WITNESSES

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

A. Columbia presents the following witnesses:

- Company witness Melissa Bartos, Vice President of Concentric Energy Advisors, 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 Bartos also explains the projection of the future test year and fully projected future test year customer and load growth.

- Company witness Melissa Bell is a Lead Regulatory Analyst for NiSource Corporate Services Company ("NCSC"). 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, the future test year ending November 30, 2021 and for the twelve months ending December 31, 2022 (FPFTY).
- Company witness Kelley Miller is a Lead Regulatory Analyst for NCSC. 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 Operating & Maintenance ("O&M") expenses.
- Company witness John J. Spanos is the President Gannett Fleming Valuation and Rate Consultants, LLC. In Columbia Statement No. 5, Company witness Spanos supports the depreciation study Gannett Fleming prepared for Columbia's gas plant.

- Company witness Nicole Shultz is a Lead Analyst for NCSC. 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 Projected Future Test Year rate base as presented in Exhibits 8 and 108.
- Company witness Ray Brumley is the Director of Construction Services for Columbia. In Columbia Statement No. 7, Company witness Brumley will discuss Columbia's ongoing replacement activities and provide testimony in support of Columbia's plant additions through the Fully Projected Future Test Year (twelve-months ending December 31, 2022).
- Company witness Paul Moul is 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 this 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 Nicole Paloney is the Director of Rates and Regulatory Affairs for Columbia. In Columbia Statement No. 9, Company witness Paloney provides testimony in support of the budgeted O&M expenses for the Fully

Projected Future Test Year that are included in Columbia witness Miller's cost of service analysis.

- Company witness Jennifer Harding is the Director of Income Tax at NCSC. In Columbia Statement No. 10, Company witness Harding 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. Witness Harding also addresses the Company's proposed Federal Tax Reform Adjustment ("FTRA") rider.
- Company witness Chad Notestone is a Lead Analyst for NCSC. In Company Statement No. 11, he testifies about Columbia's allocated cost of service studies. Company witness Notestone will also address the Company's RNA proposal, revenue allocation and rate design.
- Company witness Ribeka Danhires is Manager of Rates for Columbia. In Columbia Statement No. 12, Company witness Danhires explains and supports the tariff changes that the Company seeks to make in this proceeding. Included in these changes is proposed tariff language to provide for the acceptance of renewable natural gas onto the Columbia system and the establishment of an FTRA rider:
- Company witness Deborah Davis is Columbia's Manager of Universal Services. In Columbia Statement No. 13, Company witness Davis addresses Columbia's efforts to raise voluntary contributions for Columbia's Hardship

Fund, as well as Columbia's customer engagement efforts in response to COVID-19.

- Company witness Curtis Anstead is the Vice President and General Manager for Columbia. In Columbia Statement No. 14, Company witness Anstead provides an overview of Columbia's distribution system, 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. In addition, he provides information regarding Columbia's Distribution Integrity Management Program ("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 2020.

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. I am also supporting Exhibit 113, Schedule 1, which documents tariff changes resulting from the requested increase.

Q. Does this conclude your direct testimony?

A. Yes.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Exhibit I – 1
Columbia Gas of Pennsylvania, Inc.
Management and Operations Audit
Functional Area 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				
Customer Service			X		
Purchasing and Materials Management	X				
Emergency Preparedness	X				
Human Resources		X			
Fleet Management		X			
Information Technology	X				

D. Benefits

Where possible, the auditors estimated the potential savings expected from implementing the recommendations made in this report. The audit report contains potential cost savings of $272,000 to $332,000, annually. We tried to identify, whenever practical, the potential savings, net of the projected costs, for implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues; whereas, others would result in 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, actual benefits from effective implementation of the recommendations are subject to uncertainty and could be higher or lower than the estimate. An overall summary of the annual and one-time costs savings quantified in the audit report are shown in Exhibit I – 2 on the next page.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Exhibit I – 2
Columbia Gas of Pennsylvania, Inc.
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Implement various strategies to reduce arrearage levels such as increasing CAP enrollment and effective calculation of internal arrearage data to appropriately monitor and manage arrearage performance. (VIII – 2)	$92,000	
Complete an analysis of the third-party retention application to evaluate program efficacy in reducing CSR turnover rates by December 31, 2020. (VIII – 5)	$180,000 - $240,000	
Total	**$272,000 - $332,000**	**-**

For most of the recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was 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 nor was not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

CPA will have options to implement the recommendations and, as a result, the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Recommendation Summary

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

- INITIATION – Estimated time frame for how quickly CPA should be able to initiate its implementation efforts given CPA's resources and general operating environment. The time necessary to complete implementation will vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to implement the recommendation.

COLUMBIA GAS OF PENNSYLVANIA, INC.

- BENEFITS – Net quantifiable benefits are provided, where they could be estimated, as discussed in Section D – Benefits. Our estimated overall level of benefit rankings is not solely based on quantifiable dollars but considers the auditors' assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of CPA and/or the services it provides.

  - HIGH BENEFIT – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

  - MEDIUM BENEFIT – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

  - LOW BENEFIT – Implementation of the recommendation is likely to result in service improvements, improvements in management practices and performance, and/or enhanced cost controls.

Exhibit I – 1
Peoples Companies
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 Relationships and Cost Allocations				X	
Financial Management		X			
Gas Operations				X	
Customer Service			X		
Emergency Preparedness	X				
Human Resources		X			
Materials Management		X			
Information Technology	X				
Fleet Management			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. The audit report contains quantified potential annual cost savings of approximately $329,000 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.

Exhibit I – 2
Peoples Companies
Focused Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Increase third-party line hit damage collection performance by transferring the responsibilities to the General Counsel to actively pursue and litigate damage claims.	**Peoples Gas:** $121,000 **Equitable Division:** $66,000	-
Expedite the implementation of a uniform Theft of Service (TOS) program for the Peoples Companies.	**Peoples Gas:** $54,000	
Study potential solutions to reduce arrearages and minimize write-offs.	**Peoples Gas:** $43,000	-
Implement Automated Meter Reading (AMR)/smart meter technology as planned to minimize meter reading and billing errors.	**Peoples Gas:** $35,000 **Peoples TWP:** $10,000	-
Subtotals by Company Peoples Gas Total Equitable Division Total Peoples TWP Total **Totals for All Companies**	 $253,000 $66,000 $10,000 $329,000	-

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 Peoples Companies 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 XIII 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:

- INITIATION TIME FRAME – Estimated time frame on how quickly the Peoples Companies should be able to initiate its implementation efforts given the Peoples Companies' resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our estimated overall level of benefits rankings are not solely based on quantifiable dollars but rather the Audit Staff's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the Peoples Companies and/or the services it provides.

  - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

  - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

  - LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I-1
UGI Utilities, Inc.
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		
Information Technology		X			
Customer Service			X		
Fleet Management		X			
Human Resources / Diversity		X			

D. Benefits

Where possible, the auditors 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 $336,090 to $713,019 in annual savings and $3,360,900 to $7,130,196 in one-time savings from effective implementation of the recommendations. We 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 auditors. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

Exhibit I-2
UGI Utilities, Inc.
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
X-1. Improve company-wide inventory turnover and exclude emergency stock from inventory turnover calculations.	$336,090 - $713,019	$3,360,900 - $7,130,196

For most of the recommendations, it is not possible or practical to estimate quantitative benefits as they are of a qualitative nature or insufficient data was 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. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

UGI Utilities will have options to implement the recommendations and so the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted to the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

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

- INITIATION TIME FRAME – Estimated time frame for how quickly UGI Utilities should be able to initiate its implementation efforts, given UGI Utilities' resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided, where they could be estimated, as discussed in Section D - Benefits. Our estimated overall level of benefits rankings is not solely based on quantifiable dollars, but the auditor's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of UGI Utilities, and/or the services it provides. In addition, the ratings weight the avoidance of future adverse conditions based upon the potential severity of the adverse condition. In this form, high consequence conditions could garner a higher benefit rating than conditions occurring frequently but with a lower impact.

- HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, avoidance of substantial consequences, and/or significant cost savings.

- MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, avoidance of unfavorable but manageable consequences, and/or meaningful cost savings.

- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

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 and Organizational Structure		x			
Corporate Governance		x			
Affiliated Interests and Cost Allocations	x				
Financial Management	x				
Gas Operations	x				
Customer Service		x			
Purchasing and Materials Management	x				
Emergency Preparedness	x				
Human Resources		x			
Fleet Management		x			
Information Technology	x				

D. Benefits

Where possible, the auditors try to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. However, for most of the recommendations, it is not possible or practical to estimate quantitative benefits as their benefits are of a qualitative nature or insufficient data was 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 or implementation of good business practices could result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

NFGDC will have options to implement the recommendations and so the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted to the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

Chapters III through XIII detail the 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:

- INITIATION TIME FRAME – Estimated time frame for how quickly NFGDC should be able to initiate its implementation efforts, given NFGDC's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided, where they could be estimated, as discussed in Section D - Benefits. Our estimated overall level of benefits rankings is not solely based on quantifiable dollars, but the auditor's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of NFGDC, and/or the services it provides.

  - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

  - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

  - LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

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. 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. 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.

Exhibit I-2
PECO Energy Company
Focused Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Reduce overtime levels, specifically non-storm overtime, for C&M and DSO. (Recommendation VII-2)	$2,400,000 – $5,000,000	$0
Reduce gas line hit damages by mitigating mapping data errors and implementing a preemptive and comprehensive program to locate facilities with an emphasis on plastic pipe. (Recommendation VIII-1)	$200,000	$0
Perform a periodic comprehensive system-wide review of emergency and inactive inventory and eliminate inventory, as appropriate (Recommendation X-1)	$333,000 – $467,000	$2,200,000 – $3,110,000
Totals	$2,933,000 – $5,667,000	$2,200,000 – $3,110,000

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. The Audit Staff forecasted possible costs for implementation of the Company's expansion of inspection activities of contractor performed work to range between $500,000 and $700,000. It should be noted that the Audit Staff did not attempt to quantify resultant savings from increased inspection activity but contends that the net long term savings should ultimately outweigh the cost.

E. Recommendation Summary

Chapters III through XVII 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:

- INITIATION TIME FRAME – Estimated time frame on how quickly the Company should be able to initiate its implementation efforts given the Company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our estimated overall level of benefits rankings are not solely based on quantifiable dollars but rather the Audit Staff's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the Company and/or the services it provides.

    - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

    - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

    - LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

COLUMBIA STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

July 14, 2021

Q. Please state your name and business address.

A. Mark Kempic, 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 President and Chief Operating Officer.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. First, I will respond to the direct testimony of Office of Small Business Advocate witness Knecht, wherein he suggests that due to "growing societal and political concerns" relative to fossil fuels, and the "potential for increased CO2 emissions" on the Company's Commission-approved Long Term Infrastructure Improvement Plan, that the Company's investments may not be prudent. Second, I will respond to the testimony of Office of Consumer Advocate witness Effron relative to Columbia's projections for capital expenditures in both the Future Test Year ("FTY") and the Fully Projected Future Test Year ("FPFTY"). Lastly, I will address the testimony submitted in this matter by Richard C. Culbertson on June 16, 2021.

Q. Would you please respond to the statements in OSBA witness Knecht's testimony regarding the prudency of Columbia's infrastructure replacement program.

A. Absolutely. At the outset, as I noted in in my direct testimony, Columbia's large and growing capital program is necessary to retire and replace aging infrastructure, which is vital so that the Company can continue to provide safe and reliable service. The infrastructure is nearing the end of its useful life, so it must be replaced to continue to provide natural gas service to existing customers. In addition, the Company's large scale pipeline replacement program provides the ancillary benefit of energizing the local economies through the wages paid to the skilled labor necessary to complete the work.

Q. Please continue.

A. In his testimony Mr. Knecht makes a number of broad statements regarding the prudency of Columbia's ongoing commitment to replace aging infrastructure due to "the potential for increased regulation of CO2 emissions", and "growing societal and political concerns" regarding fossil fuels. On the basis of these statements, Mr. Knecht seeks to criticize Columbia for not having a financial plan longer than five years to evaluate these potentials. And, again based upon his statements, concludes that the Commission should direct Columbia, "to demonstrate that it has long-term viable business as part of its next LTIIP filing."

Q. Does Mr. Knecht provide support for these statements?

A. No, he does not. In fact, Mr. Knecht does not cite to any specific laws or regulations in support of his contentions. Moreover, the Pennsylvania law authorizing the fully projected future test year also sets forth a five year review process for utility's long term infrastructure investments, so Mr. Knecht's claim of possible imprudence due to not having a plan longer than five years is not supported by the structure set forth by the General Assembly in Pennsylvania law. In addition, regardless of any political or societal concerns that may or may not develop in the future, the fact remains that natural gas distribution facilities which are reaching the end of their useful life must be replaced in order to keep customers served by those facilities safe. Moreover, if such facilities are not replaced, existing customers served by those facilities would face substantial costs to replace their gas-fired equipment. Mr. Knecht also does not recommend any expense or revenue adjustments, so his recommendation should be dismissed because in addition to it being inconsistent with the spirit and intent of Pennsylvania law, it is vague.

Q. Are you aware of the Commission addressing any similar arguments?

A. Yes. I am advised by counsel that similar arguments were recently advanced in a base rate case filed by the Philadelphia Gas Works. [1] Similar to Mr. Knecht's testimony on this issue, the Commission determined that the environmental parties in the PGW case failed to provide any evidence to support an affirmative position, such as a specific expense or an adjustment to revenue projections. Further, the Commission denied the environmental parties' request that PGW be required to perform studies and prepare reports based on speculative assertions, and in the absence of statutory, regulatory or other legal order or requirement to do so.

[1] *PaPUC v. Philadelphia Gas Works*, Docket No. R-2020-3017206 (November 19, 2020).

Q. Is the PGW decision instructive in this case?

A. It certainly appears so. In this case, much like the environmental parties in the PGW case, Mr. Knecht raises a general concern about the prudency of Columbia's capital plan as it relates to infrastructure replacement. However, he provides no evidentiary support for his concerns, advocates for no expense or revenue adjustments, but, yet, he seeks to require the Company justify its viability as a company in a future proceeding wholly unrelated to this case. For these reasons, Mr. Knecht's assertions, and requested relief, should be rejected by the Commission.

Q. Would you please comment on OCA witness Effron's proposed adjustment related to plant additions?

A. Yes, I would. While Columbia witness Brumley will address the specific shortcomings of Mr. Effron's proposed adjustment, I want to address the inappropriateness of this proposed adjustment, particularly in light of Columbia's consistent performance in meeting, and exceeding, its projections. In addition, I will discuss the potential serious policy considerations should the Commission adopt the OCA's proposed adjustment to plant additions in this case.

Q. Please continue.

A. In his direct testimony, Mr. Effron recommends that the Commission adjust the Company's 2021 and 2022 forecasted plant additions by averaging net plant additions for the years 2019 and 2020 to determine the Company's plant additions for 2021 and 2022.

Q. Is this the first time the OCA has made this proposal?

A. No. In the Company's 2020 rate case, Columbia provided projections for the FTY (2020) and FPFTY (2021) plant additions, and evidence reflecting the success that Columbia has had throughout its use of the FPFTY to meet, or exceed its projections. Based in large measure on arguments relative to the uncertainty associated with the impact of COVID-19 on the Company's work plans, the Commission adopted a similar adjustment. However, it is inappropriate to do so again.

Q. Please explain.

A. Unquestionably 2020 presented the Commission with a difficult environment to assess the ability of the Company to continue to meet its plant additions projections. However, Columbia, through the hard work and safe work practices employed by our employees and contractors, is on track to meet the projections of 2021 plant additions made in support of the Company's 2020 requested revenue increase. This is not surprising, as the Company has routinely met or exceeded its projected plant additions, as reflected in the table below. Additionally, as shown in the table below, Columbia is making great progress placing natural gas facilities into service during the first five months of 2021 prior to lifting of remaining COVID-19 restrictions, which some may have thought would have a negative impact on Columbia's ability to replace pipe this year.

Gross Plant in Service					
Docket	Month	Budget	Actuals	(Over/Under)	
R-2012-2321748	12/31/2013	152,919,055	147,212,243	(5,706,812)	-3.73%
R-2014-2406274	12/31/2014	173,221,267	168,513,084	(4,708,183)	-2.72%
R-2015-2468056	12/31/2015	168,600,200	176,521,638	7,921,438	4.70%
R-2016-2529960	12/31/2017	241,193,780	246,180,352	4,986,572	2.07%
R-2018-2647577	12/31/2019	258,343,265	294,610,057	36,266,792	14.04%
R-2020-3018835	5/31/2021	62,716,770	82,615,906	19,899,136	31.73%

Q. What do you suggest that the Commission take from this chart?

A. That Columbia's projections related to its infrastructure replacement program are based on a realistic work plan, and when Columbia accelerates its investments in replacement pipe, it has historically met its accelerated plant in service goals, through proper planning, realistic work plans and proper staffing. Furthermore, as Witness Brumley testifies, Columbia's capital program is not driven by the level of plant additions made in the past, but instead, the Company's capital plan is driven by the need for the replacement of priority pipe. Columbia has increased, and will continue to increase, its replacement of priority pipe as long as there is a need to reduce risk by replacing that pipe which is nearing the end of its useful life. Therefore, Columbia's projections concerning plant in service at the end of 2021 and 2022 should be adopted.

Q. Would you like to make any other comments relative to the OCA proposal?

A. Yes, I would. Again, while Columbia disagreed with the Commission's decision to adopt the OCA's adjustment relative to plant additions in its 2020 rate case, the potential impact of COVID-19 provided the Commission with a unique set of facts that could have impacted the Company's projections. However, despite these concerns, Columbia, through the work of employees and contractors, successfully operated its 2020 infrastructure replacement program, and is again on track in 2021. To again adopt the OCA's plant adjustment in this case would not reflect a reasonable interpretation of Columbia's past or future expected work efforts, and only serve to undermine the intent of the FPFTY.

Q. Please explain.

A. As stated in the Commission's Orders during the Implementation of Act 11 of 2012, the intent of the FPFTY is to encourage utilities to accelerate and replace aging infrastructure now, rather than wait, by removing the disincentives.

> "Act 11 is a three-legged ratemaking stool that provides a stable regulatory framework needed to support accelerated infrastructure replacement with improved gradualism in rate changes and enhanced oversight and customer safeguards. The three components- DSIC, a fully projected Future Test Year, and combining water and wastewater rate cases, will work in concert to facilitate investment by mitigating the disincentive and expense of the previously existing ratemaking process. As noted in a recent American Water Works Association report, 'Deferring needed investments today will only result in greater expenses tomorrow and pass on a greater burden to our children and grandchildren.' Act 11 gives us the mechanisms to confront our

> infrastructure challenges now and do so across the board- for gas, electricity, water and wastewater." Docket No. M-2012-2293611, Statement of Robert F. Powelson, Public Meeting: August 2, 2012

Columbia's continued acceleration of investments in replacing priority pipe are consistent with established policy; the investments are necessary, reasonable and prudent in order to continue to provide safe and reliable natural gas distribution service; and Columbia's past performance in planning, staffing and executing its capital program are strong indicators that Columbia will yet again achieve its stated plant in service at the end of 2022.

Q. Richard C. Culbertson, who identifies himself as the owner of rental properties in Columbia Gas of Pennsylvania's service territory, submitted a document on June 16, 2021 that he has designated to be his written testimony. Do you have any response to Mr. Culbertson's submittal?

A. Yes. His submittal is not really a presentation of evidence that creates a record for the Commission's consideration that one would normally expect to see as testimony in a proceeding before the Commission. Rather, it appears to be a treatise or brief in opposition to the result of Columbia's 2020 Rate Case and the Company's request for a rate increase in the current case. To that end, his submittal is more in the nature of legal argument rather than testimony and it may not be appropriate to accept it as testimony in this case. However, seeking to have Mr. Culbertson's submittal stricken would involve the diversion of the Company's resources to drafting a motion to strike while the Company is focusing on rebuttal testimony. Such a motion would also divert the Commission's resources to the consideration of that motion as well as a responsive pleading by Mr. Culbertson. Rather than diverting Columbia and Commission resources to adjudicating a motion to strike those portions of Mr. Culbertson's submission that are legal arguments, Columbia will address his arguments at the briefing stage of this case.

Q. Did Mr. Culbertson make any factual assertions that you wish to rebut?

A. Yes. First, Mr. Culbertson makes several references to the testimony of Michael Hicks, who testified during the afternoon public input hearing on June 16, 2021. Mr. Hicks testified that he cannot afford to install a customer service line in order to restore gas service to his home. In response to Mr. Culbertson's references to Mr. Hicks' testimony, I would refer to Columbia Statement No. 14-R, the rebuttal testimony of Columbia witness Anstead. Mr. Anstead explains the facts and circumstances regarding the termination of Mr. Hicks' service and why Mr. Hicks is responsible for the replacement of his service line in order to re-establish his service with Columbia. I would also like to address Mr. Culbertson's assertion, on page 56 of his submission, that "NiSource was forced to adopted (*sic*) ANSI/API 1173 – *Pipeline Safety Management Systems*" as a result of the October 2018 Merrimack Valley incident in Massachusetts. That is simply untrue. Prior to that incident, NiSource had already implemented SMS in Virginia, and had plans to implement it in its remaining operating companies, including Columbia Gas of Pennsylvania.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

M. BARTOS

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

March 30, 2021

TABLE OF CONTENTS

I. Introduction

Q. Please state your name and business address.

A. My name is Melissa Bartos. My business address is 293 Boston Post Road West, Suite 500, Marlborough MA 01752.

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

A. I am employed by Concentric Energy Advisors ("Concentric"). My current title is Vice President.

Q. Please briefly describe your professional experience.

A. My entire career, which expands over twenty years, has been in energy consulting. I began my career with Reed Consulting Group, which was later purchased and merged into Navigant Consulting, Inc. I joined what is now Concentric Energy Advisors in 2002. Both firms specialize in consulting for the energy industry.

Q. Please describe your educational background.

A. I received a Bachelor of Arts in Mathematics and Psychology with a concentration in Computer Science in 1998 from the College of the Holy Cross in Worcester, Massachusetts. I received a Master of Science degree in Mathematics with a concentration in Statistics in 2003 from the University of Massachusetts at Lowell.

Q. What are your responsibilities in your current position?

A. In my current position as a Vice President at Concentric, I am responsible for the execution of numerous projects related to the energy industry. I specialize in demand forecasting, rates and regulatory issues and market analysis. My resume is attached as Appendix A.

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

agency?

A. I have not previously testified before the Pennsylvania Public Utility Commission, but I have testified before several other state, federal, and Canadian provincial regulatory agencies on dozens of occasions. My testimony list is attached as Appendix B

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

A. I will be addressing the twelve-month period ending November 30, 2020 as the Historic Test Year ("HTY"), the twelve-month period ending November 30, 2021 as the Future Test Year ("FTY"), and the twelve-month period ending December 31, 2022 as the Fully Projected Future Test Year ("FPFTY").

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 Melissa Bell's testimony (Columbia Statement No. 3) and Exhibit 003, Schedule 04. I will also explain the forecast methodology used to develop forecasted number of customers and usage for the FTY and the FPFTY. The results of the forecast are contained in Exhibit 010, Schedule 02.

II. <u>Weather Normalization of Historical Test Year</u>

Q. Please explain the weather normalization methodology.

A. At a high level, actual sales per customer are separated into base use and temperature-sensitive use per customer for each month of the HTY for the residential and commercial classes. Monthly temperature-sensitive use per customer is adjusted by the ratio of normal to actual heating degree days ("HDD") by month to derive normal temperature-sensitive use per customer by month. The monthly normal temperature-sensitive use per customer is added to the base use per customer to arrive at the normal sales per customer. This value is multiplied by the customer count by month to produce monthly normal sales. All calculations are performed on a billing month basis and use billing month sales, the average number of days in the billing cycle, and billing month HDD.

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

A. I use the Company's billing records to obtain monthly customer counts and billed sales for the residential and commercial classes for the HTY. I use temperatures from DTN, a weather consulting service which aggregates National Weather Service weather stations relevant to the Company's service territory, to calculate HDD. I rely on temperature data from five weather stations due to the geographical dispersion of Columbia's customers. A weighted average HDD for the Company is calculated by using the percent of residential customers assigned to each station as a weight for that station.

Q. How is base usage determined?

A. Base usage is the portion of usage that is not dependent on weather, i.e., not temperature-sensitive. I assume that there is no temperature sensitive usage in the summer months of July and August, therefore, all usage in July and August is base use and is not affected by the weather normalization process. In addition, the total use per customer per day (Total Use/Customer/Day) for July and August is all base use. If total use per customer per day in September is less than July or August, then I also assume September has no temperature sensitive usage (i.e., September is also assumed to be a base use-only month and not affected by the weather normalization process). The base use per customer per day used to weather normalize the remaining months of the HTY is calculated by averaging the two lowest observed use per customer per day values from the months of July through September.

Q. How are monthly sales in the remaining months weather normalized?

A. The base use per customer per day is multiplied by the number of days ((base use/customer/day)*days in billing cycle) to produce monthly base use per customer. Temperature-sensitive use per customer equals the total use per customer minus the base use per customer. The temperature-sensitive use per customer is normalized for weather by multiplying it by a ratio of normal HDD to actual HDD. Normal use per customer is calculated by adding the base use per customer to the normal temperature-sensitive use per customer. Total monthly normalized usage is generated by multiplying monthly normal use per customer by the monthly customer count. This calculation for the HTY is prepared separately for residential and commercial customers and the results are presented in Exhibit 010, Schedule 08.

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

A. No, the methodology has not changed since Columbia's last rate filing. However, the historical average HDD have been updated to include the most recent 20-year history (i.e., 20 years ended December 31, 2020). The previous base rate case filing defined normal weather as the 20-year average ending in 2019. In all other respects, the weather normalization process is the same.

Q. Why is Columbia using a 20-year average HDD in the weather normalization process?

A. The Company continues to use the 20-year average HDD in the weather normalization process because it is consistent with the Company's approach since 2008. In addition, an analysis of weather data demonstrates that a rolling 20-year average is a superior predictor of one-year-ahead HDD and five-year ahead HDD than the 30-year average HDD, and the 20-year average HDD is a more dynamic measure than the 30-year average HDD, as discussed in more detail below.

Q. Please explain your analysis that demonstrates that the 20-year average HDD is a better predictor of one-year-ahead and five-year ahead HDD than the 30-year average HDD.

A. Table 1, below, compares the actual HDD experienced each year from 1984 through 2020 with the historical average HDD calculated using either the prior 20-years or the prior 30-years. The absolute error is calculated as the absolute value of the difference between the actual HDD and either the 20-year or 30-year average. Table 1 demonstrates that the 20-year average HDD has a lower absolute error than the 30-year average HDD in 70% of the most recent 37 years. Table 1 also illustrates that the 20-year average HDD has a lower mean absolute error when predicting the one-year-ahead HDD, as compared to the 30-year average HDD when considering the most recent 37-year period.

In Table 2, the 20-year and 30-year average HDD are used to predict annual HDD for each five-year period for the five years ended 1988 through the five years ended 2020. As measured by the smallest difference over the five-year period, the 20-year average HDD outperforms the 30-year average HDD in 94% or 31 out of the 33 periods. When considering the most recent ten periods, the 20-year average HDD outperforms the 30-year average HDD in 100% or all of the ten periods.

Table 1

Weather Averages as Predictors

Moving Averages used to Predict Following Year

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
1983		5893	5880				
1984	6040	5904	5898	147	160	x	
1985	5340	5879	5892	564	558		x
1986	5593	5863	5887	286	299	x	
1987	5495	5842	5885	368	392	x	
1988	5960	5835	5881	119	75		x
1989	5816	5824	5882	19	65	x	
1990	5010	5779	5852	814	872	x	
1991	4919	5734	5815	860	933	x	
1992	5572	5719	5796	162	243	x	
1993	5512	5733	5771	207	284	x	
1994	5739	5747	5768	6	32	x	
1995	5518	5746	5757	229	250	x	
1996	5962	5738	5759	216	205		x
1997	5649	5714	5750	89	110	x	
1998	4619	5636	5701	1095	1131	x	
1999	5185	5594	5672	451	516	x	
2000	5442	5560	5657	152	230	x	
2001	5435	5517	5644	125	222	x	
2002	5348	5491	5627	169	296	x	
2003	5876	5502	5648	385	249		x
2004	5384	5469	5645	118	264	x	
2005	5607	5482	5648	138	38		x
2006	5216	5463	5617	266	432	x	
2007	5342	5456	5591	121	275	x	
2008	5573	5436	5571	117	18		x
2009	5447	5418	5552	11	124	x	
2010	5460	5440	5530	42	92	x	
2011	5459	5467	5502	19	71	x	
2012	4711	5424	5463	756	791	x	
2013	5526	5425	5459	102	63		x
2014	5998	5438	5457	573	540		x
2015	5524	5438	5463	86	67		x
2016	4774	5379	5436	664	689	x	
2017	4760	5334	5411	619	676	x	
2018	5692	5388	5403	358	281		x
2019	5250	5391	5384	138	153	x	
2020	4858	5362	5379	533	526		x

	Mean Absolute Error		Frequency of Lowest Absolute Error	
1984-2020	301	330	26	11

	Relative Frequency of Lowest Absolute Error	
1984-2020	70%	30%

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
1983		5893	5880				
1984	6040	5904	5898				
1985	5340	5879	5892				
1986	5593	5863	5887				
1987	5495	5842	5885				
1988	5960	5835	5881	-1037	-970		x
1989	5816	5824	5882	-1315	-1288		x
1990	5010	5779	5852	-1520	-1586	x	
1991	4919	5734	5815	-2117	-2236	x	
1992	5572	5719	5796	-1931	-2149	x	
1993	5512	5733	5771	-2348	-2574	x	
1994	5739	5747	5768	-2369	-2658	x	
1995	5518	5746	5757	-1636	-2000	x	
1996	5962	5738	5759	-367	-771	x	
1997	5649	5714	5750	-217	-600	x	
1998	4619	5636	5701	-1177	-1366	x	
1999	5185	5594	5672	-1803	-1906	x	
2000	5442	5560	5657	-1874	-1928	x	
2001	5435	5517	5644	-2358	-2465	x	
2002	5348	5491	5627	-2541	-2719	x	
2003	5876	5502	5648	-893	-1218	x	
2004	5384	5469	5645	-486	-876	x	
2005	5607	5482	5648	-151	-633	x	
2006	5216	5463	5617	-155	-788	x	
2007	5342	5456	5591	-28	-708	x	
2008	5573	5436	5571	-386	-1116	x	
2009	5447	5418	5552	-158	-1042	x	
2010	5460	5440	5530	-372	-1201	x	
2011	5459	5467	5502	-35	-804	x	
2012	4711	5424	5463	-628	-1305	x	
2013	5526	5425	5459	-578	-1251	x	
2014	5998	5438	5457	65	-605	x	
2015	5524	5438	5463	17	-431	x	
2016	4774	5379	5436	-803	-976	x	
2017	4760	5334	5411	-539	-732	x	
2018	5692	5388	5403	-376	-545	x	
2019	5250	5391	5384	-1189	-1286	x	
2020	4858	5362	5379	-1857	-1982	x	

	Mean Absolute Error		Frequency of Lowest Error	
1988-2020	-1005	-1355	31	2
2011-2020	-592	-992	10	0

Relative Frequency of Lowest Error

1988-2020	94%	6%
2011-2020	100%	0%

Q. Please explain your analysis that demonstrates that the 20-year average HDD is more dynamic than the 30-year average HDD.

A. Table 3 demonstrates that the average annual change for the 20-year average HDD is 0.4%, while the average annual change for the 30-year average is 0.3% HDD. The 20-year normal HDD is a more dynamic measure that is better able to react more quickly to weather changes because it replaces 5% of the data each year rather than the 3% that is replaced with the 30-year average.

Table 3

Weather Averages
Annual Change in Averages 1984-2020
Absolute Values
Columbia Gas of Pennsylvania

	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	7.0%
Maximum	1.4%	0.8%	19.6%

III. Demand Forecast Methodology for Future Test Year and Fully Projected Future Test Year

A. Demand Forecast Methodology Overview

Q. Please explain the methodology employed for developing the forecasted number of customers and volume for the FTY and FPFTY.

A. Total residential and total commercial customers and volume for both the FTY and FPFTY are forecasted using econometric models. Total industrial volume for both the FTY and FPFTY are forecasted based on knowledge gained through relationships with large industrial customers. Total residential, total commercial, and total industrial forecasts are subsequently split into sales, choice, and GTS customers and volumes, as appropriate, using historical data.

Q. What data sources do you use to develop the econometric models for the residential and commercial classes?

A. I use the Company's billing records through November 2020 to obtain historical monthly customer counts and billed usage for the residential and commercial customer classes. Historical billed usage is divided by historical customer counts to produce monthly historical use per customer data for residential and commercial customers. The historical customer counts and use per customer are used as the dependent variables in the residential customer, residential use per customer, commercial customer, and commercial use per customer econometric models.

Several sources are used to obtain data for the independent variables included in the econometric models. Historical and forecast gas price data is sourced from the U.S. Energy Information Administration ("EIA"). Historical and forecast average efficiency data is provided by Itron Inc., a national utility consulting firm. Historical and forecast values for economic and demographic variables (e.g., number of households and non-manufacturing equipment) and deflator data are from IHS Global Insight, Inc., a data consultant. Historical weather data (HDD) is provided by DTN, a weather consulting service, and the same 20-year average HDD described in the weather normalization process above is used as the weather during forecast period.

Q. How are the economic effects associated with COVID-19 incorporated into the forecast?

A. Data indicates that COVID-19 had three identifiable impacts on customer counts and usage. First, on a very short-term basis, the shut-downs associated with COVID-19 appear to have affected use per customer for some classes in the spring and early summer of 2020. These short-term impacts are addressed when necessary by including a dummy variable[1] in the econometric model to account for specific months in 2020 in which the use per customer significantly differed from what would have been expected absent the shut-downs. These impacts on use per customer are not expected to persist into the FTY and FPFTY as the most significant shut-downs are largely over. Therefore, it is not necessary to make additional adjustments to the forecast associated with impacts on use per customer associated with the temporary COVID-19 shut-downs.

Second, prohibitions on terminations of customers (i.e., moratoriums on customer shut-offs) due to the economic effects of COVID-19 ("COVID-19 Moratoriums") affected customer counts starting in the spring of 2020 and continue to affect customer counts. As will be described in more detail below, FTY residential and commercial customer counts were adjusted to capture the impacts of the ongoing COVID-19 Moratorium that were not captured by the econometric models, but FPFTY customer counts were not adjusted as it is anticipated that customer counts will return to expected levels before the start of the FPFTY.

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[1] In this case, a dummy variable (or indicator variable) is an independent variable that represents a time-related event. The dummy variable equals 1 when the specific time-related event occurs and equals 0 outside of that specific time. The coefficient on the dummy variable is determined through the econometric modeling process. Statistical results associated with the econometric model identify whether the dummy variable is significant.

Third, shut-downs and changes in consumer activity associated with COVID-19 affected the local and national economy, which in turn affects natural gas customers and usage. For example, unemployment spiked in the spring of 2020, and while unemployment has declined from the peak, it is currently expected to take time for employment levels to return to pre-COVID levels. The economic impacts associated with COVID-19 are incorporated into the FTY and FPFTY forecast through the use of economic independent variable data. Historical and forecasted economic data series used in the econometric models reflect the economic outlook of IHS Global Insight as of December 2020. Therefore, short term and long term COVID-19 economic impacts on customer counts and usage are incorporated in the forecasts produced by the econometric models and the forecasts do not require further adjustment to account for economic conditions related to COVID-19.

B. <u>Residential Forecast</u>

Q. Please describe the residential customer forecast methodology.

A. The residential customer forecast is developed using a monthly econometric model that incorporates the number of households, several monthly variables for shaping, and a trend. As described above, residential customer counts in 2020 were affected by the moratorium on customer shut-offs due to the economic impacts of COVID-19. As shown by the orange line in Figure 4 below, residential customer counts typically are highest in the winter and decrease in the summer as customers are shut-off, (i.e., removed or terminated) for non-payment or other reasons. The prohibition on terminations that the Public Utility Commission ordered in March 2020 resulted in residential customer counts that remained at higher-than-normal levels throughout the remainder of 2020. Termination procedures will resume at the end of this winter (i.e., April 1, 2021) because the Commission has lifted the ban on terminations due to COVID, and the typical winter moratorium will end at that time. From a modeling perspective, dummy variables are added to the residential customer count model for each month of April 2020 through November 2020 (the end of the historical data set) to account for the fact that the customer count data for this period does not reflect normal business conditions. These dummy variables essentially eliminate the impact of the COVID-19 Moratorium on the econometric model and result in a forecast that does not include the effects of the COVID-19 Moratorium, illustrated by the green "Raw Model Output" line on the graph in Figure 4.

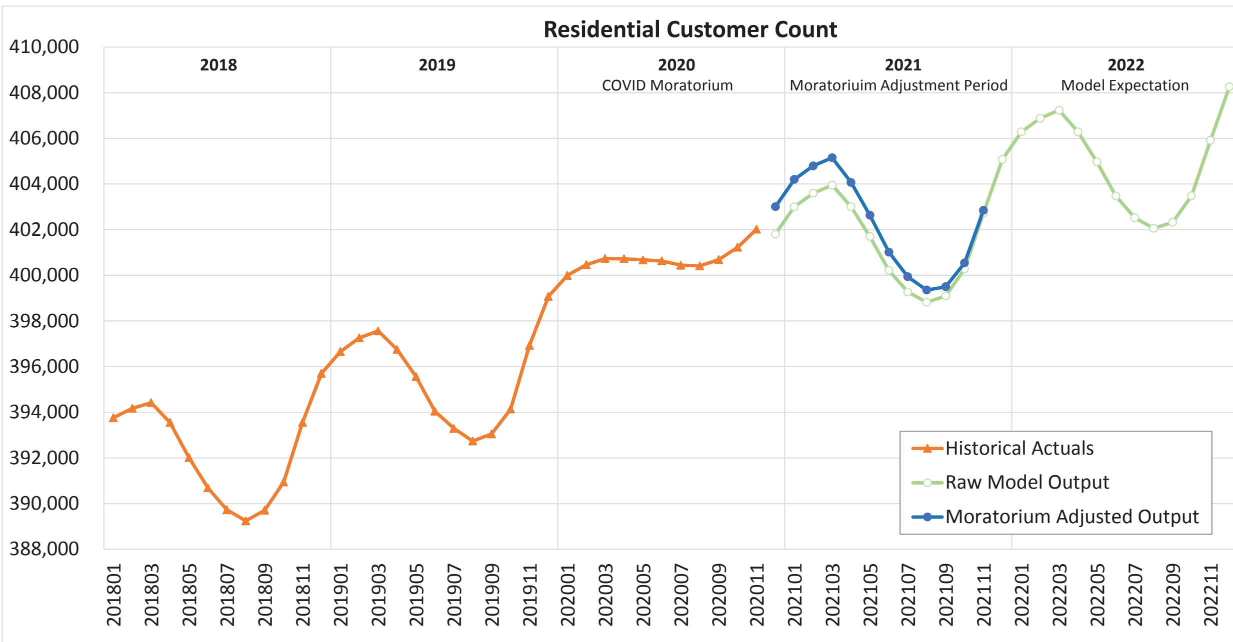
Q. How is the COVID-19 Moratorium accounted for in the residential customer forecast?

A. The residential customer forecast is based on the moratorium on shut-offs remaining in place through March 31, 2021, therefore, the residential customer count forecast produced by the econometric model for the months of December 2020 through March 2021 is increased by 1,200 customers (approximately 0.3%) to account for the additional residential customers that are estimated to be on the system as a result of the COVID-19 Moratorium, as shown by the blue line in the graph in Figure 4. This is not based upon a specification of individual customers that would have been terminated, but represents an estimation of the additional residential customers who currently are being served by Columbia above the customer count that would have been anticipated but for the COVID-19 Moratorium. The level of the residential moratorium adjustment is based on 2020 monthly customer counts compared to previous years, the values of the April 2020-November 2020 dummy variables in the econometric model, and 2017-2019 levels of final terminations at the end of the year (i.e., after restorations related to dormant account survey).

Q. Please explain how the adjustment for the moratorium on shut-offs associated with COVID-19 is phased out of the forecast.

A. The Company will not terminate all qualifying customers effective April 1, 2021. The Company will require several months to communicate with customers who are behind on their bills to work with the customers to develop payment arrangements as required per the order issued on March 18, 2021 at Docket M-2020-3019244 and identify newly-available assistance funding and to execute its termination process and procedures in compliance with Commission-approved processes. It is expected that over time the differential of 1,200 additional residential customers will phase out as termination procedures are reinstated and the normal cycle of customer counts will return. Given the information available at this time, it is estimated that customer counts will return to normal business conditions (i.e., the 1,200 additional residential customers that were assumed to be associated with the COVID-19 moratorium will be addressed) by December 2021. Therefore, adjustments are necessary for the remainder of the FTY to account for the gradual reduction of the 1,200 residential customer differentials resulting from the COVID-19 Moratorium. For the purposes of the customer count forecast for the FTY, it is assumed starting in April 2021 the 1,200 residential customer increase is reduced by an equal proportion, such that by December 2021 no adjustment is made, and the forecast returns to the levels produced by the econometric model as shown in the blue line in Figure 4. The adjustments associated with the COVID-19 moratorium only affect the months of December 2020-November 2021, so only the FTY is impacted. The FPFTY customer count forecast is the unadjusted forecast resulting from the econometric model.

Figure 4



Q. Please describe the residential use per customer forecast methodology.

A. The residential use per customer forecast is developed using a monthly econometric model that incorporates weather in the form of HDD, real natural gas prices, energy intensity, and several monthly variables for additional shaping. As described above, residential use per customer was temporarily affected by the shut-downs associated with COVID-19. From a modeling perspective, a dummy variable was added to the residential use per customer count model for the month of April 2020 because data indicates that residential use per customer was significantly affected in that month. This dummy variable essentially eliminates the impact of the short-term COVID-19 shut-downs on the econometric model and results in a forecast that does not include these short-term effects.

Q. How is the forecast of monthly residential volume determined?

A. Monthly residential customer counts are multiplied by monthly residential use per customer to produce monthly residential volume.

Q. How are the total residential customers and usage split into residential sales and residential CHOICE?

A. Residential CHOICE customer counts are based on extrapolating the recent declining trend in residential CHOICE customers. Residential sales customer counts is determined by subtracting residential CHOICE customer count from the total residential customer count.

Use per customer for residential CHOICE customers has been higher than use per customer for residential sales customers in recent years. Forecasted use per customer for residential CHOICE customers is determined by applying the historical monthly ratio of residential CHOICE use per customer to total residential use per customer. Forecasted residential CHOICE usage is determined by multiplying residential CHOICE customers by residential CHOICE use per customer. Residential sales usage is determined by subtracting residential CHOICE usage from the total residential usage.

C. Commercial Forecast

Q. Please describe the commercial customer forecast methodology.

A. The commercial customer forecast is developed using a monthly econometric model that incorporates non-manufacturing employment levels and several monthly variables for shaping. As described above, commercial customer counts in 2020 were also significantly affected by the moratorium on customer shut-offs due to the economic impacts of COVID-19. As shown by the orange line in Figure 5 below, commercial customer counts typically are highest in the winter and decrease in the summer as customers are shut-off, (i.e., removed or terminated) for non-payment or other reasons. The prohibition on terminations that was ordered by the Public Utility Commission in March 2020 resulted in commercial customer counts that remained at higher-than-normal levels throughout the remainder of 2020. As I mentioned earlier in my testimony, shut-offs are permitted to resume on April 1, 2021. From a modeling perspective, dummy variables are added to the commercial customer count model for each month of April 2020 through November 2020 (the end of the historical data set) to account for the fact that the customer count data for this period does not reflect normal business conditions. These dummy variables essentially eliminate the impact of the moratorium on shut-offs in the econometric model and result in a forecast that does not include the effects of the moratorium on shut-offs, illustrated by the green “Raw Model Output” line on the graph in Figure 5.

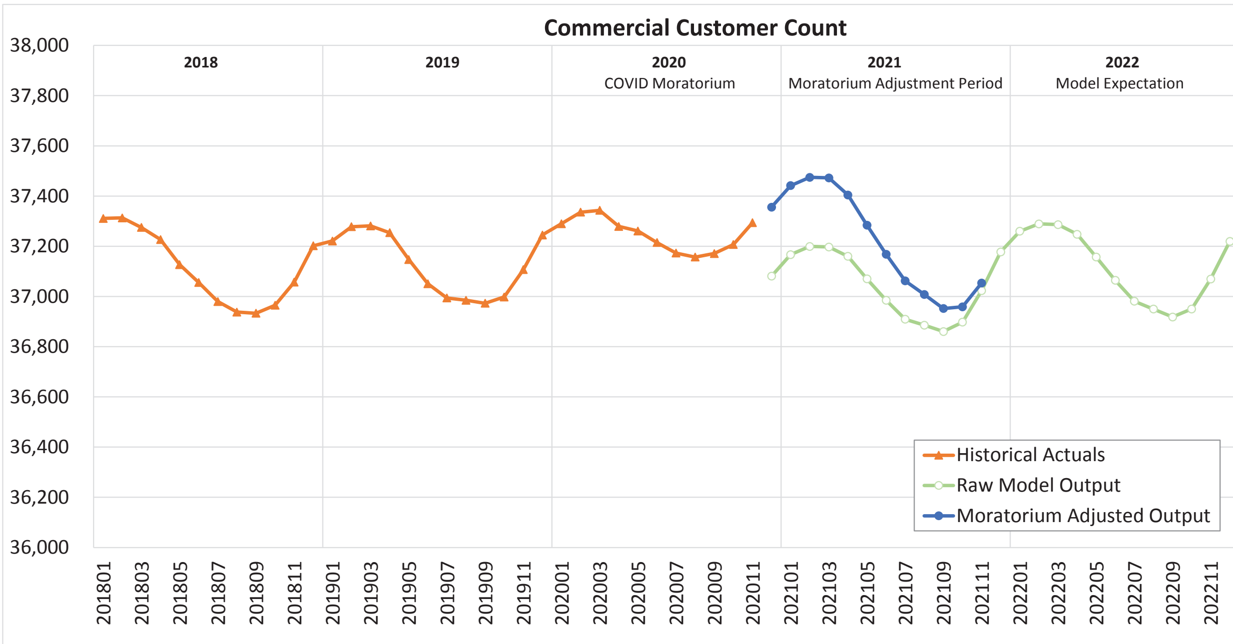
Q. How is the COVID-19 Moratorium accounted for in the commercial customer forecast?

A. Consistent with the residential analysis described above, it was assumed that a moratorium on shut-offs would remain in place through March 31, 2021, therefore, the commercial customer count forecast produced by the econometric model for the months of December 2020 through March 2021 is increased by 275 customers (approximately 0.7%) to account for the customers that are estimated to be on the system as a result of the COVID-19 Moratorium, as shown by the blue line in the graph in Figure 5. Again, this is not based upon a specification of individual customers that would have been terminated, but represents an estimation of the additional commercial customers who currently are being served by Columbia above the customer count that would have been anticipated but for the COVID-19 Moratorium. The level of the moratorium adjustment is estimated by reviewing 2020 monthly customer counts compared to previous years and the values of the April 2020-November 2020 dummy variables in the econometric model.

Q. Please explain how the adjustment for the COVID-19 Moratorium is phased out of the forecast.

A. Consistent with the residential adjustment the COVID-19 Moratorium described above, for the purposes of the customer count forecast for the FTY, it is assumed starting in April 2021 the 275-customer increase is reduced by an equal proportion each month, such that by December 2021 no adjustment is made, and the forecast returns to the levels produced by the econometric model as shown in the blue line in Figure 5. The adjustments associated with the COVID-19 Moratorium only affect the months of December 2020-November 2021, so only the FTY is impacted. The FPFTY customer count forecast is the unadjusted forecast resulting from the econometric model.

Figure 5



Q. Please describe the commercial use per customer forecast methodology.

A. The commercial use per customer forecast is developed using a monthly econometric model that incorporates weather in the form of HDD, real natural gas prices, and several monthly variables for additional shaping. As described above, commercial use per customer was temporarily affected by the shut-downs associated with COVID-19. From a modeling perspective, a dummy variable is added to the commercial use per customer count model for each of the months of April, May, June, and October 2020 because commercial use per customer was significantly lower than expected during these months. This dummy variable essentially eliminates the impact of the short-term COVID-19 shut-downs on the econometric model and results in a forecast that does not include these short-term effects.

Q. How is the forecast of monthly commercial volume determined?

A. Monthly commercial customer counts are multiplied by monthly commercial use per customer to produce monthly commercial volume.

Q. How are the total commercial customers and volumes split into commercial sales, commercial CHOICE, and commercial GTS?

A. Commercial GTS and commercial CHOICE customers are forecasted to remain at recent historical customer levels. Commercial sales customers are the customers remaining when commercial GTS and commercial CHOICE customers are subtracted from the total commercial customer forecast. Total commercial usage is allocated to sales, GTS and CHOICE based proportions experienced in the most recent 12-months.

D. <u>Industrial Forecast</u>

Q. Please describe the industrial forecast methodology.

A. The industrial forecast is provided by the Large Customer Relations group by incorporating information generated through individual customer interviews. Since the Large Customer Relations group covers over 90% of the total industrial volumes, it is assumed that the remaining industrial customers grows at the same rate as those forecasted by the Large Customer Relations group.

Q. How is the total industrial usage split into industrial sales and industrial GTS?

A. Total industrial usage is allocated to sales and GTS based upon monthly proportions experienced in the most recent 24-months.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MELISSA F. BARTOS
Vice President

Ms. Bartos is a financial and economic consultant with more than twenty years of experience in the energy industry. In the last several years, she has focused on natural gas markets issues, including conducting comprehensive market assessments for various clients considering infrastructure investments and developing detailed demand forecasts for a number of gas distribution companies. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony on multiple occasions regarding natural gas demand forecasting and supply planning issues, natural gas markets and marginal cost studies.

REPRESENTATIVE PROJECT EXPERIENCE

Natural Gas Market Assessments

- Reviewed and evaluated long-term natural gas supply and demand, existing natural gas pricing dynamics, and future implications associated with new natural gas infrastructure in New England, New York, and New Jersey.
- Provided an analysis of the existing Gulf Coast natural gas market, the client's natural gas pipeline competitors, changing flows, and how those factors may affect transportation values to the client going forward.
- Prepared a comprehensive study examining the costs associated with improving natural gas pipeline access from western Canada and the eastern U.S. to Atlantic Canada.
- Produced a report on the benefits associated with incremental natural gas supplies delivered to New York City.
- Prepared an independent natural gas supply and pipeline transportation route assessment associated with natural gas for the client's proposed LNG export terminal.
- Conducted a study that examined potential commercial and industrial conversions from oil-based fuels to natural gas in various east coast U.S. markets.
- Produced a report that identified growth potential in off-system stationary and mobile markets in the mid-west that could be served by compressed natural gas or liquefied natural gas.
- Performed an external audit and filed expert testimony associated with two natural gas utilities' hurdle rate/contribution in aid of construction calculations for new off main customers.

- Produced a report that identified and reviewed innovative cost model approaches that utilities and regulators are using across the U.S. that allow expansion of gas distributions systems to new communities.
- Assisted in developing a strategy to identify residential natural gas growth opportunities within the client's franchise area.
- Presented at two Northeast Gas Association conferences regarding "Regulatory Policy and Residential Main Extensions".
- Conducted a study to determine the cost of significantly reducing peak day natural gas demand for a northeast gas utility through energy efficiency, conservation and demand management measures. Project involved researching natural gas energy efficiency plans in multiple U.S. states and Canadian provinces, reviewing energy efficiency potential studies, and exploring geothermal, peak pricing and direct load control options.

Demand Forecasting

- Filed expert testimony regarding the development of demand forecast models and the evaluation of natural gas resource plans for several gas utilities.
- Provided litigation support regarding demand forecasting techniques with respect to certain natural gas pipeline and storage decisions for a mid-west gas utility.
- Evaluated demand forecasts and produced alternative demand forecasts in the context of due diligence support for several asset transactions.
- Reviewed demand forecasting practices and procedures and recommended certain changes to improve the methodology and accuracy of the forecast for a multi-state utility.
- For a mid-west gas utility, developed a natural gas demand forecast that was utilized for supply and capacity decisions.

Ratemaking and Utility Regulation

- Participated in the rate case of a large North American gas distribution company, which determined the client's five-year incentive regulation plan, including performing benchmarking and productivity analyses that were filed with the regulator.
- Developed and testified in support of several marginal cost studies filed in rate cases for several New England utilities.
- Provided comprehensive analysis, drafted testimony and provided litigation support regarding the appropriate return on equity for a New England water utility, and for proposed wind and coal electric generation facility additions for a mid-west combination utility.
- Performed a detailed analysis of the components included in the client's lost and unaccounted for gas calculation.
- Conducted multiple natural gas portfolio asset optimization analyses to evaluate performance of the client's asset manager for regulatory purposes.

- On behalf of multiple New England gas companies, participated in the 2009 Avoided Energy Supply Cost Study Group (for New England), which worked with third-party consultants to develop the marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Vice President
Assistant Vice President
Project Manager
Senior Consultant

Navigant Consulting, Inc. (1996 – 2002)
Senior Consultant

EDUCATION

University of Massachusetts at Lowell
M.S., Mathematics (Statistics), 2003

College of the Holy Cross
B.A., Mathematics and Psychology, *magna cum laude*, 1998

PROFESSIONAL ASSOCIATIONS

Member of the American Statistical Association

Member of the Northeast Energy and Commerce Association

Member of the Northeast Gas Association

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2014	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 13-06-02	CIAC Hurdle Rate Calculation
Federal Energy Regulatory Commission				
PennEast Pipeline Company, LLC	2015	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
PennEast Pipeline Company, LLC	2016	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
Millennium Pipeline Company, LLC	2017	Millennium Pipeline Company, LLC	Docket No. CP16-486	Market Conditions/Need
Laclede Gas Company	2017	Spire STL Pipeline, LLC	Docket No. CP17-40	Market Conditions/Need
Maine Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	Docket No. 2011-526	Integrated Resource Plan; Demand Forecast
Massachusetts Department of Public Utilities				
New England Gas Company	2008	New England Gas Company	D.P.U. 08-11	Integrated Resource Plan; Demand Forecast; Supply Planning
New England Gas Company	2010	New England Gas Company	D.P.U. 10-61	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2010	Berkshire Gas Company	D.P.U. 10-100	Integrated Resource Plan; Demand Forecast
New England Gas Company	2012	New England Gas Company	D.P.U. 12-41	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2012	Berkshire Gas Company	D.P.U. 12-62	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2014	NSTAR Gas Company	D.P.U. 14-63	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2014	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Liberty Utilities (New England Gas Company)	2015	Liberty Utilities (New England Gas Company)	D.P.U. 15-75	Marginal Cost of Service Study
Berkshire Gas Company	2016	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Eversource Energy	2017	Eversource Energy (NSTAR Electric and WMECO)	D.P.U. 17-05	Marginal Cost of Service Study
National Grid (Boston Gas Company and Colonial Gas Company)	2017	National Grid (Boston Gas Company and Colonial Gas Company)	D.P.U. 17-170	Marginal Cost of Service Study
Bay State Gas Company d/b/a/ Columbia Gas of Massachusetts	2018	Bay State Gas Company d/b/a/ Columbia Gas of Massachusetts	D.P.U. 18-45	Marginal Cost of Service Study
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-40	Marginal Cost of Service Study
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-107	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2019	NSTAR Gas Company	D.P.U. 19-120	Marginal Cost of Service Study
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	2019	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	D.P.U. 19-135	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2020	Berkshire Gas Company	D.P.U. 20-139	Integrated Resource Plan; Demand Forecast
Boston Gas d/b/a National Grid	2020	Boston Gas d/b/a National Grid	D.P.U. 20-120	Marginal Cost Study
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	DG 2011-290	Integrated Resource Plan; Demand Forecast
Liberty Utilities (EnergyNorth Natural Gas)	2017	Liberty Utilities (EnergyNorth Natural Gas)	DG 17-048	Marginal Cost of Service Study
Liberty Utilities (Granite State Electric)	2019	Liberty Utilities (Granite State Electric)	De 19-064	Marginal Cost of Service Study
New Jersey Board of Public Utilities				
South Jersey Gas Company	2015	South Jersey Gas Company	GR15010090	Energy Efficiency Cost Benefit Analysis

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ontario Energy Board				
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study
Enbridge Gas Distribution	2013	Enbridge Gas Distribution	EB-2012-0459	Incentive Rate Making
Régie de l'énergie du Québec				
TransCanada Pipelines Ltd.	2014	TransCanada Pipelines Ltd.	R-3900-2014	Natural Gas Market Assessment
Washington Utilities and Transportation Commission				
Puget Sound Energy, Inc.	2015	Puget Sound Energy, Inc.	UG-151663	Distributed LNG Market Assessment

M. BELL

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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 Inc. 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"), Columbia Gas of Kentucky ("CKY"), and Columbia Gas of Virginia ("CVA"). The types of filings include earnings tests, monthly gas cost adjustments, infrastructure replacement, 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 that time, I joined CSC Energy Solutions as a Tariff Analyst until February 2003. In March 2003, I was employed by NCSC in the Gas Transportation Services ("GTS") Department as a GTS Analyst II, providing sales support to Major Account Representatives for Columbia, CMD and CVA, 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 testified before the Pennsylvania Public Utility Commission ("Commission") in Columbia's previous base rate proceedings, at Docket Nos. R-2020-3018835, R-2016-2529660, R-2014-2406274, and R-2012-2321748, and in a formal complaint proceeding during my tenure as a GTS analyst. I have also submitted testimony in CMD's base rate proceedings, Case Nos. 9644, 9609, 9447, 9417 and 9316; in CKY 2016 base rate proceeding, Case No. 2016-00162; and Columbia Gas of Massachusetts's 2015 base rate proceeding, D.P.U. 15-50.

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

A. In connection with those various rate case proceedings, I prepared and submitted testimony on rate base, allocated cost of service, and 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, 2022 (which is the Fully Projected Future Test Year, or "FPFTY"). These 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. I will also sponsor and describe Exhibits 3 and 103 (Operating Revenues). I am also sponsoring the following exhibits:

Exhibit No.
Exhibit 003, Schedule 01 through 10, (02) (03) (04) Pages 01-05
Exhibit 010, Schedule 03, (22), Page 01
Exhibit 010, Schedule 04, (38), Page 01
Exhibit 010, Schedule 07, (03) (14), Page 01
Exhibit 012, Schedule 01, (05) Page 01
Exhibit 012, Schedule 02 (18), Pages 01-02
Exhibit 012, Schedule 03, (23) Page 01
Exhibit 012, Schedule 04, (24 (26) (30) (36), Page 01
Exhibit 012, Schedule 04, (25) Page 01
Exhibit 012, Schedule 05, (31), Page 01
Exhibit 012, Schedule 06, (11) Page 01
Exhibit 012, Schedule 07, Pages 01-02
Exhibit 012, Schedule 08, Page 01
Exhibit 016, (7), Pages 01-04
Exhibit 017, (01) (28) Pages 01-07
Exhibit 103, Schedules 01 through 7, (02) (03) (04), Pages 01-15
Exhibit 110, Schedule 03, (22), Page 01
Exhibit 110, Schedule 04, (38) (39), Page 01
Exhibit 110, Schedule 07, (03) (14), Page 01
Exhibit 112, Schedule 01 (05) Page 01
Exhibit 112, Schedule 02, (18) (23) thru (26) (30) (31) (36) (11) Pages 01-04
Exhibit 112, Schedule 03, Pages 01-03
Exhibit 112, Schedule 04, Page 01
Exhibit 116, (07), Page 01
Exhibit 117, (01) (28), Pages 01-02

Q. Are you sponsoring any additional exhibits?

A. Yes. Attached to my testimony are two additional exhibits that support the Company's revenue proposal. Each exhibit, identified below, will be addressed later in my testimony.

Exhibit No.	Description
Exhibit MJB-1	Calculation of the Merchant Function Charge
Exhibit MJB-2	Annualization of Forfeited Discounts (Account 487)

III. Operating Revenues

A. 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 following calculations are made to determine the number of bills 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 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 – 7. 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 Exhibit 3, Schedule 2, Column 7 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, 2020. 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 – 7

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 Melissa Bartos (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 Universal Service Plan ("USP") and Merchant Function Charge ("MFC") and Rider Customer Choice ("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 and Rider USP rate as of January 1, 2021, which is the most recent available at the time the schedules were developed. The Merchant Function Charge ("MFC") rate (please refer to Exhibit MJB–1, attached to this testimony) was updated to reflect the January 1, 2021 PGC rate and the proposed residential and non-residential uncollectible expense ratio as calculated by Company witness Miller and shown in Exhibit No. 4, Schedule 2, Page 27, Lines 7 and 14. The State Tax Adjustment Surcharge ("STAS") last changed January 1, 2016 and remains at 0%.

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 years ending November 2017, November 2018 and November 2019, and calculates a three-year average. This three year period 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 FPFTY revenue (Exhibit 103), resulting in annualized Forfeited Discounts revenue for those test years shown on Exhibit MJB-2, pages 2 and 3 respectively.

Q. Why is the Company not using data from the Twelve Months Ended November 30, 2020 as a part of the three year average?

A. As stated by Company Witness Miller, the Company determined that 2020 data is highly irregular and should not be used for determining annualized Forfeited Discounts. The irregular results are due to the COVID-19 Pandemic and the associated Emergency Order issued by the PUC on March 13, 2020. In response to the Pandemic and the Emergency Order, the Company suspended billing and collection of forfeited discounts, or late payment charges, on customer's late and unpaid bills. This action has caused the level of forfeited discounts billed during the HTY to be extremely low compared to previous years, and is therefore not appropriate to use in calculation of determining the normal levels of forfeited discunts.

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, 2020. Columns 2 through 6 show the calculated split of per books gas cost, Rider USP, GPC, MFC and 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 9. Column 10 reflects pricing out the test year billing determinants (bills and volumes) at the most current base rates. Column 11 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, 2021. Column 3 shows a summary of Rider USP at present rates in effect as of January 1, 2021. Column 5 shows a summary of the MFC. 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.

B. Exhibit 103

Q. Please describe the projection of bills for the FTY and FPFTY.

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 Bartos on Exhibit 10, Schedule 2. The customer counts are then spread for each month of the FTY and the FPFTY, based on the HTY experience, by rate schedule, by customer class, and 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 FPFTY 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 FPFTY 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 FPFTY 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 FPFTY. Therefore, the HTY final bill 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 FPFTY.

Q. Please explain the process used to develop FTY and FPFTY Dth.

A. Forecasted adjusted Dth for both the FTY and the FPFTY are shown in Exhibit 103, Schedule 3, Column 6 and 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 FPFTY.

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 Bartos in Exhibit 10, Schedule 2. These Dth are spread for each month of the FTY and FPFTY based on the HTY by rate schedule, by customer class, and by type of service for Residential Sales and CHOICE customers. The spread for Commercial and Industrial Sales and CHOICE transportation customers and 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 FPFTY. Adjustments resulting from Large Commercial and Industrial customers either discontinuing or adding service during the FTY and FPFTY are shown by customer in Exhibit 103, Schedule 4, Pages 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 is shown on Exhibit 103, Schedule 4, Pages 10 and 11 and Pages 14 and 15 for the FPFTY. 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 FPFTY 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 FPFTY, respectively, reflecting the rate design as shown on Exhibit 103, Schedule 8, sponsored by Company witness Chad E. Notestone.

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 FPFTY.

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

A. The difference between the revenue in the FTY and the FPFTY year is driven by changes in customer growth, attrition, changes in use per customer, expected changes in customer counts, and usage for large customers based upon a customer by customer review. See Witness Bartos' testimony for an explanation of the forecast models.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Calculation of Merchant Function Charge Utilized in Exhibit No. 3 and Exhibit No. 103
Calculated Using Gas Costs as of January 1, 2021

Line No.	Description	Reference		Rate $	
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/2021 Quarterly GCR Filing)		1.7679	
2	Total Commodity Cost of Gas			**1.7679**	per Dth
3	Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 7	0.0152077		
4	Non-Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 14	0.0030875		
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)		0.0269	per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)		0.0055	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, 2020

Line No.		12 Mos November 2017	12 Mos November 2018	12 Mos November 2019	Total 3 Year Average	
1	Per Books Acct 487	$ 1,082,094	$ 1,130,923	$ 1,080,703	$ 3,293,720	
2	Per Books Billed Revenue	$ 534,990,949	$ 584,115,062	$ 602,529,915	$ 1,721,635,926	
3	Forfeited Discounts as a % of Revenue	0.2023%	0.1936%	0.1794%	0.1913%	
	(Line 1 / Line 3)					
4	Historic Test Year Sales Revenue					$ 464,529,949
	(Ex. 3, Page 10, Column 7, Line 6)					
5	Historic Test Year Revenue -Transportation Revenue					$ 182,170,428
	(Ex. 3, Page 10, Column 7, Line 9)					
6	Total Sales and Transportation Revenue					$ 646,700,377
	(Line 5 + Line 6)					
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts					$ 1,237,138
	(Line 7 * Line 6)					
9	Historic Test Year Acct 487					$ 502,806
	(Ex. 3, Page 9, Column 1, Line 7)					
10	Annualization Adjustment					$ 734,332
	(Line 8 - Line 9)					

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2021

Line No.		12 Mos November 2017	12 Mos November 2018	12 Mos November 2019	Total 3 Year Average	
1	Per Books Acct 487	$ 1,082,094	$ 1,130,923	$ 1,080,703	$ 3,293,720	
2	Per Books Billed Revenue	$ 534,990,949	$ 584,115,062	$ 602,529,915	$ 1,721,635,926	
3	Forfeited Discounts as a % of Revenue	0.2023%	0.1936%	0.1794%	0.1913%	
	(Line 1 / Line 3)					
4	Future Test Year Sales Revenue					$ 475,173,151
	(Ex. 103, Page 11, Column 8, Line 5)					
5	Future Test Year Transportation Revenue					$ 180,251,461
	(Ex. 103, Page 11, Column 8, Line 8)					
6	Total Sales and Transportation Revenue					$ 655,424,612
	(Line 4 + Line 5)					
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts					$ 1,253,827
	(Line 4 * Line 6)					
9	Future Test Year Acct 487					$ 1,237,138
	(Ex. 103, Page 10, Column 1, Line 6)					
10	Annualization Adjustment					$ 16,689
	(Line 7 - Line 8)					

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2022

Line No.		12 Mos November 2017	12 Mos November 2018	12 Mos November 2019	Total 3 Year Average	
1	Per Books Acct 487	$ 1,082,094	$ 1,130,923	$ 1,080,703	$ 3,293,720	
2	Per Books Billed Revenue	$ 534,990,949	$ 584,115,062	$ 602,529,915	$ 1,721,635,926	
3	Forfeited Discounts as a % of Revenue	0.2023%	0.1936%	0.1794%	0.1913%	
	(Line 1 / Line 3)					
4	Fully Projected Future Test Year Sales Revenue					$ 483,085,572
	(Ex. 103, Page 15, Column 8, Line 5)					
5	Fully Projected Future Test Year Transportation Revenue					$ 176,847,118
	(Ex. 103, Page 15, Column 8, Line 8)					
6	Total Sales and Transportation Revenue					$ 659,932,690
	(Line 5 + Line 6)					
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts					$ 1,262,451
	(Line 7 * Line 6)					
9	Fully Projected Future Test Year Acct 487					$ 1,253,827
	(Ex. 103, Page 14, Column 1, Line 6)					
10	Annualization Adjustment					$ 8,624
	(Line 8 - Line 9)					

COLUMBIA STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

July 14, 2021

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. Have you previously filed testimony in this matter?

A. Yes. I submitted direct testimony on March 30, 2021. I am also adopting the direct testimony of Columbia witness Chad Notestone (Columbia Statement No. 11).

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I will be addressing several arguments and conclusions presented in the direct testimony of Mr. Cline, witness for the Bureau of Investigation and Enforcement ("I&E"), Mr. Mierzwa, witness for the Office of Consumer Advocate ("OCA"), Mr. Knecht, witness for the Office of Small Business Advocate ("OSBA"), and Mr. Crist, witness for the Pennsylvania State University ("PSU"), on the subject of Allocated Cost of Service Studies ("ACCOSS"), revenue allocation to rate classes, rate design, and the establishment of a Revenue Normalization Adjustment ("RNA") mechanism. In addition, I will be addressing several arguments and conclusions presented in the direct testimony of Mr. Geller, witness for the Coalition for Affordable Utility Services and Energy Efficiency In Pennsylvania ("CAUSE-PA") on the subjects of rate design, and the establishment of a Revenue Normalization Adjustment ("RNA") mechanism, and Mr. Brady, witness for Pennsylvania Weatherization Providers Task Force ("WPTF") on the subject of rate design. Finally, in my rebuttal testimony, I will be addressing Mr. Cline's recommend adjustment of miscellaneous service revenue to be increased by $59,635 and Mr. Mierzwa's recommendations for Competitive Alternative Analysis presented in the Company's next base rate case.

II. Allocated Cost of Service Studies and Revenue Allocation

Q. The Company presented three separate ACOSS (Customer/Demand, Peak & Average, and Average Study). Please explain why three studies were prepared and why the Company principally relied upon the Peak & Average study as a guide to revenue allocation.

A. The Customer/Demand Study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class while the Peak & Average Study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia Gas of Pennsylvania ("Columbia" or "CPA") recognizes that no one cost of service study is the "right" study and, in the past, concluded that the results of two such studies provide a reasonable range of returns for use as a guide in establishing appropriate rates. The third study, as presented in Exhibit No. 111, Schedule 3, is an average of the Customer/Demand Study and the Peak & Average Study and represents what Columbia believes is a reasonable range of revenue responsibility. This Average Study, with its equal weighting of the two former studies, provides the Company, the parties and the Commission with a range of returns that can be used as a benchmark or guide in revenue allocation.

In Columbia's most recent rate case (Docket No. R-2020-3018835, p. 218, Order entered February 19, 2021), the Commission states, "we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment." Consistent with the Commission's Order in the 2020 rate case, the Company utilized the Peak & Average Study as the primary study to serve as a guide to allocate the cost of mains and mains related cost as a guide to allocate the proposed revenue increases in this case.

Q. Other than the Peak and Average allocated cost of service study, what other guidelines or criteria did Columbia consider in the design of the Company's revenue allocation among the rate classes?

A. Mr. Notestone stated in his direct testimony on pages 16 and 17 that "Columbia believes the results from the other two studies (Customer/Demand and Average) can still be useful as another reference point in guiding the allocation of the proposed revenue increase. The results of the cost allocation studies support the Company's proposed rate schedules." In addition, on Page 20 of his direct testimony, Mr. Notestone stated "First, the design of Columbia's rates recognizes that rates must be just and reasonable and must not be unduly discriminatory".

Q. What is I&E witness Cline's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Cline agreed with the Company's use of the Peak & Average Study consistent with the Commission's ruling in the last rate case. Mr. Cline also recommends that the Company continue to utilize the peak and average cost of service study to establish rates in future rate cases.

Q. What is OCA witness Mierzwa's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Mierzwa also agreed with the Company's use of the Peak & Average Study, consistent with the Commission's ruling in the last rate case.

Q. What is OSBA witness Knecht's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Knecht stated on page 15 of his direct testimony that "While I disagree with the Commission's findings regarding mains cost allocation in the last rate case, I accept the method employed by the Company in its P&A ACOSS for reasons of Commission precedent."

Q. What is PSU witness Crist's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Crist prefers the Company's Customer Demand study (Exhibit No. 111, Schedule 1) as a method of cost allocation. Mr. Crist supports his preference based on what he has identified as facts and engineering. Mr. Crist attached to his direct testimony a Company response to data request PSU 1-001 that describes in detail how the Company sizes its distribution system piping in new construction. The Company's response stated:

> In general, sizing mainlines within our distribution systems is based upon many factors. They include: the MAOP (maximum allowable operating pressure), the normal operating pressure, the minimum operating pressure (under peak conditions), the delivery pressure requested on behalf the customer, the length of main, and of course load information (typically in terms of Mcfh - 1000 cubic foot per hour).

When Mr. Crist asked about meter and service line sizing in response to PSU 1-006 Columbia stated:

> The connected load of a customer moving into an existing facility would be based upon the total rating (either in BTUs - British Thermal Units, or cubic feet of gas per hour) of the gas appliances to be used by the customer. This information is provided to Columbia of PA, Inc., by the customer. Once the load information has been determined, the service line would be sized based upon the factors identified in the response to PSU 1-001.

Mr. Crist noted the following on page 15 of his direct testimony:

> None of the data used for pipe sizing and distribution system planning, engineering, and construction include annual commodity usage. Repeatedly Columbia asserts it considers the demand load information, expressed in terms of BTU/hr. The Company collects this BTU/hr data through its web-based tool or through customer interviews. My review of the Company's data request responses, including the Company manuals and procedures have identified that connected load, along with delivery pressure and length of pipe necessary to attach to the customer are the only data used in gas main design and sizing.

Q. Did Mr. Crist address the Commission's Order in Columbia's 2020 base rate proceeding?

A. Yes. Mr. Crist expressed his opinion that the reason the Commission selected the Peak & Average Study in Columbia's 2020 rate case is because there was an "error" in the Company's Customer-Demand Study. The "error" that Mr. Crist is referring to is the separation of gas main investment by operating pressure. Mr. Crist explained that Columbia did not separate gas mains investment by operating pressure in its Customer-Demand Study presented this case. On page 12 of Mr. Crist's testimony he pointed out that "In her decision ALJ Dunderdale stated, 'The ALJ recommends the Commission use the Peak & Average COSS, as promoted by OCA, in this base rate proceeding. Columbia Gas' Customer Demand COSS would be the preferred method, but it contains serious flaws that skews its reliability and makes it unsuitable for use at this time and with this NGDC.'" Mr. Crist also quotes the Commission's 2020 rate case Order in which the Commission stated, "we are not persuaded to reverse the ALJ's Recommended Decision that adopted the OCA's P&A ACCOSS and methodology in this proceeding." PSU Statement No. 1, p. 13.

Q. What is your response to Mr. Crist's analysis of the 2020 rate case Order?

A. From these statements it seems possible that Columbia's separation by operating pressure of customers, design day volumes and throughput that made up the mains allocation factors in that case was the "error" identified by the ALJ and that because Mr. Mierzwa's Peak and Average study was the only study presented that did not first separate by operating pressure, that may have been the deciding factor in the Commission's Decision to use the Peak and Average study in that case. The Company did eliminate the separation of mains by operating pressure in this case.

Q. How do the positions of the parties differ from the Company's on the use of the ACOSS?

A. As previously mentioned, a combination of preferences exists among the parties as to which distribution mains allocation method they prefer and which should be used as a guide in the allocation of proposed revenue increases in this case. Witness Mierzwa and Witness Cline both recommend the use of the Peak & Average Study, citing Commission precedent.

Witness Knecht disagrees with the findings regarding mains cost allocation in the last rate case by the Commission. However, he accepts the Company's Peak & Average study for reasons of Commission precedent.

Mr. Crist rejects the Company's Peak & Average and Average studies based on what he has identified as facts and engineering and therefore recommends that the Customer Demand study should be the sole basis of the allocation of proposed revenue increases in this case.

The Company recognizes this Commission's preference for the use of the Peak and Average study, and therefore, the Company used the Peak and Average study as the primary guide for the allocation of the proposed revenue increase in this case.

While the Company believes the use of the three studies is appropriate, absent further guidance from the Commission, it has concluded that the Peak and Average study should be used as the primary guide. However, the Company does not believe that basing the revenue allocation in this case entirely on the Peak & Average Study would produce a reasonable result, particularly with respect to allocation of mains cost to the LDS/LGSS class. The Company also cannot agree with Mr. Crist that the Customer/Demand study should be the sole basis of allocating revenue requirement among the rate classes.

Q. Is there reason to temper the use of the Peak and Average Study in the allocation of increases revenue to the LDS/LGSS class?

A. Table MJB-1R below shows the amount of mains cost assigned to each rate class using the Peak and Average study (Exhibit 111, Schedule 2, Page 3, Lines 20, 22-25).

Table MJB-1R

	Total Co.	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
MAINS	$2,376,689,964	$1,236,211,518	$204,537,938	$291,334,656	$200,283,663	$241,115,197	$0	$203,206,992
DIRECT - MAINS - MDS	142,006	0	0	0	0	0	71,014	70,992
MAINS-CSL REPLACEMENTS	23,515,481	12,231,342	2,023,742	2,882,528	1,981,650	2,385,646	0	2,010,574
MAINS-BARE STEEL	38,446,622	19,997,626	3,308,716	4,712,787	3,239,897	3,900,410	0	3,287,186
DIRECT - MAINS-BARE STEEL	80,803	0	0	0	0	0	80,803	0
MAINS-CAST IRON	96,846	50,374	8,335	11,871	8,161	9,825	0	8,280
TOTAL MAINS	$2,438,971,723	$1,268,490,860	$209,878,732	$298,941,842	$205,513,371	$247,411,077	$151,817	$208,584,024

Table MJB-2R below shows the breakdown of transmission and distribution mains investment by pipe diameter (Standard Data Request Question No. GAS-COS-004).

Table MJB-2R

Diameter	Quantity (feet)	Amount
1/2"	3	233
3/4"	6,101	11,390
1"	55,692	238,020
1-1/8"	1,151	5,619
1-1/4"	602,388	2,835,391
1-1/2"	8,319	11,473
2"	14,419,497	297,367,441
2-1/2"	3,773	18,811
3"	2,981,747	29,098,901
3-1/4"	0	3,764
3-1/2"	3,649	20,815
4"	11,793,181	501,673,568
4-1/2"	1,458	18,124
4-7/8"	7,635	17,413
5"	31,965	32,845
5-1/4"	11	344
5-3/16"	16,898	35,878
5-5/8"	11,180	13,923
6"	5,862,831	304,461,790
6-1/4"	15,930	5,618
6-5/8"	88,404	643,886
7-5/8"	636	25,405
8"	3,148,214	277,338,781
8-1/4"	282	2,429
8-5/8"	8,232	361,804
9-5/8"	1,269	7,380
10"	733,280	33,972,854
12"	428,860	53,083,404
14"	450	5,167
16"	341,599	36,428,783

20"	33,775	6,378,737
Total Pipe	40,608,411	1,544,119,990

With the exception of a few meters from one LDS customer, all customers that make up the LDS/LGSS rate class are attached to either 3" or greater diameter pipe. Therefore I will only use the average cost per foot to estimate the mileage of mains pipe assigned to these rate classes by the Peak & Average study. From table MJB-2R the sum of 3" and greater diameter pipe is 25,511,487 feet and $1,243,631,613 resulting in an average cost per foot of $48.75 for 3" and greater diameter pipe.

Table MJB-1R shows the Peak & Average study allocated a total of $247,411,077 of mains cost to the LDS/LGSS rate class. Dividing $247,411,077 by the average cost per foot of $48.75 results in the assignment of 5,075,099 feet or about 961 miles of mains pipe to the LDS/LGSS class. The Company's Exhibit 111, Schedule 2, Page 12, Line 11 shows there are 74 LDS/LGSS customers. Dividing the 961 miles of mains pipe assigned to the LDS/LGSS rate class by the 74 customers that make up the LDS/LGSS rate class results in the assignment of approximately 13 miles of mains for each LDS/LGSS customer.

Q. Is it reasonable to assume that Columbia has invested in on average 13 miles of pipe for each of the 74 LDS/LGSS customers and that 100% of the mileage cost should be assigned solely to those customers?

A. No. In Columbia's 2020 rate case, R-2020-3018835, Mr. Mierzwa presented in his direct testimony his Table 2. Mr. Mierzwa described his table 2 as follows: "Presented below in Table 2 are the number of feet by which CPA was required to extend its system to connect its ten largest non-MLDS customers as well as the design day and annual usage of those customers". (See Case No. R-2020-3018835 Direct testimony of Jerome D. Mierzwa, Page 12 and 13). Below is a copy of Mr. Mierzwa's Table 2 from that case.

Table 2.
Service and Usage Characteristics of CPA's
Ten Largest Non-MLDS Customers

Customer	Design Day (Dth)	Throughput (Dth)	Distance (Ft)
1	10,119	2,831,244	3,106
2	12,080	2,002,712	7,618
3	0	1,099,939	1,479
4	4,085	1,020,792	[1]
5	1,228	801,205	1,178
6	2,502	605,046	4,726
7	1,468	531,350	1,571
8	2,158	525,916	1,294
9	1,633	452,894	1,308
10	2,222	443,556	750

[1] This customer is the only one served off the main. There is no meter upstream.

Note the 10 largest customers are defined by the 10 largest non-MLDS customers Columbia services based solely on customer throughput. Mr. Mierza used the information to point out "Large-Use customers are typically located farther apart than lower-residential customers". However, the information also shows Columbia was required to extend its system in the range of 750 feet (0.1 miles) of pipe to 7,618 feet (1.4 miles) of pipe to connect its ten largest customers. The Peak and Average study assigned average cost of 13 miles of pipe to each of the 74 LDS/LGSS customers even though the Columbia only extended its system in the range of 0.1 to 1.4 miles to each of its 10 largest customers.

Q. What are possible causes of why the Peak & Average study allocates an excessive amount of mains cost to the LDS/LGSS rate class?

A. Each of Columbia's customers have a unique cost that contributes to the total cost to serve the rate class in which those customers are included. Obvious distinctions in customer costs are: 1) the distance from the transmission main to the customer meter; 2) the design day capacity of the customer; 3) the age of the pipe; 4) the customer density on the distribution main; 5) the geographic location of the main (urban vs. rural); 6) the number of customers and capacity requirements downstream of the customer; and 7) the operating pressure of the main. All are contributing factors to cost. No one allocated cost of service study accounts for each of these contributing factors, which is why after choosing an ACOS it is important to analyze the results for reasonableness.

Q. Is the Company saying the Peak and Average study should not be used in the determination of allocating revenue requirement to the rate classes?

A. No. Columbia has consistently advocated in its prior rate cases the use of the Peak and Average study in the determination of allocating revenue requirement to the rate classes. However, Columbia has never advocated the Peak and Average study as the sole basis of revenue requirement allocation. Various factors, including gradualism, value of service and alternative cost studies, are appropriately considered in revenue requirement allocation. For this case, Columbia used the peak and average study as the primary study to establish class rates of return at present and proposed rates. The peak and average study was given primary consideration given the Commission's ruling on the matter in Columbia's 2020 rate case. However, Columbia believes the results from the other two studies can still be useful as another reference point in guiding the allocation of the proposed revenue increase. The results of the cost allocation studies support the Company's proposed rate schedules.

Q. In light of the excessive mains cost allocated to the LDS/LGSS rate class as a result of the Peak and Average study, what is the Company's recommendation in how the Peak and Average study should be used in the determination of revenue allocation to the rate classes?

A. While Columbia used the Peak and Average study as the primary study for purposes of revenue allocation, Columbia must ensure that the resulting allocation of revenue to the rate classes are fair and reasonable. The Company believes in light of the mains cost allocated to the LDS/LGSS rate class, using the Peak and Average as the sole basis of determining the allocation of revenue is not fair or, reasonable. The Company believes the resulting allocated costs must be analyzed for reasonableness and to the extent there are outliners as in the case of the LDS/LGSS class, adjustments must be made before those costs can be used to determination of revenue requirement to the rate classes.

Q. How do the positions of the parties differ from the Company's in the allocation of revenue requirement among the rate classes?

A. I&E witness Cline has accepted the revenue allocation that the Company has recommended at the as filed revenue requirement.

OCA witness Mierzwa has assigned an increase of 1.85 times the system average to the LDS/LGSS rate class. Mr. Mierzwa's allocated revenue requirement to the LDS/LGSS class is in excess of the 1.5 times average system increase, which represents the upper bound for rate gradualism used by the Commission in Columbia's last rate case. Therefore the Company cannot support Mr. Mierzwa's recommendation.

Mr. Knecht also reallocated flex rate shortfall to other classes using the P&A mains allocation factor and relied on a revenue – cost ratio to help determine progress toward cost-based rates. The Company assigned the increase to the Customer charge to the Flex customers first and then used the limits of gradualism toward parity to assign the revenue requirement in this case. Mr. Knecht adopted the Company's allocation of revenue requirement with the exception of allocating an additional $1.8 million from the residential class to the LDS class. By doing so, Mr. Knecht's allocated revenue requirement to the LDS/LGSS class is in excess of the 1.5

times average system increase, which supports the upper bound for rate gradualism used by the Commission in Columbia's last rate case. For this reason, Mr. Knecht's proposal violates the principles of gradualism, and the Company cannot agree with Mr. Knecht's proposed allocation of an additional $1.8 million from the residential class to the LDS class.

Q. Mr. Miezwa recommends on page 4 of his direct testimony that each Competitive Alternative Analysis presented for Flex customers in the Company's next base rate case should also evaluate whether the revenues provided by each Flex rate customer exceeds the long-term marginal cost of service and that rates charged to Flex rate customers should be sufficient to recover the long-term marginal cost of service. Do you agree such a mandate should be adopted for Columbia's next base rate case?

A. No. There should not be a mandate as to the type of analysis or information Columbia develops to support granting a flex rate. There is no filing requirement as to what information is necessary to meet the Company's burden of proof on this issue. There is also no definition provided as to what a "long term marginal cost study" is, and this could mean different things to different parties. For example, if a main used to serve a flex rate customer serves 100 other customers, it can be argued that there is no marginal investment cost to serve the customer, since the main would be there regardless of whether the customer is retained on the system.

Others might claim that some type of main investment should be included in an incremental cost analysis.

III. Scale Back of Rates

Q. I&E witness Cline proposes that in the event the Commission recommends less than the $98,278,240 increase in revenue requirement request in this case, that the first $36 million reduction be applied to the revenue requirement assigned by the Company to the residential class, the next $26.7 million be applied to the SGS/GS-1 and SGS/SG-2 classes to align with the LDS/LGSS class. Do you agree?

A. No. Mr. Cline is trying to get to parity in one rate case and by doing so he is exceeding any reasonable definition of gradualism. If both reductions were made to the total company revenue requirement as Mr. Cline suggests, the total Company increase would be $35,578,240 ($98,278,240 - $36,000,000 - $26,700,000), but the increase for the LDS/LGS class would remain at $5,895,248. Stated differently, the percent increase to total company would be 5.4%, but the percentage increase to the LDS/LGSS class would remain at 29.6%. That is a change of 5.5 times the average increase where the Commission agreed with 1.5 times the average increase as the upper bound for rate gradualism in the Company's last rate case.

IV. Customer Charge

Q. Do you agree with I&E witness Cline's statement on page 17 of his direct testimony the Company's customer cost analysis that includes the cost of mains is invalid?

A. No. A customer charge should include at a minimum the incremental cost the utility incurs in connecting a customer to the distribution system. Some call this a "readiness to serve" charge. Unfortunately the Peak and Average study does not differentiate the cost of extending the gas main to the customer from the capacity cost to serve the customer on a design day.

Q. Do you agree with I&E witness Cline's statement on page 18 of his direct testimony that based on the customer cost analysis that does not include the cost of mains, the customer charges proposed by the Company for the SGS1, SGS2, and SDS/LGSS classes are too high?

A. No. The customer cost study is a study that defines the minimum cost to serve a customer regardless of consumption. Mr. Cline is using the study as a maximum charge to recover fixed cost through fixed recovery. Columbia recognizes that the customer cost analysis shows a minimum floor in which fixed costs should be recovered. To the extent that additional fixed cost is recovered through the customer charge, in excess of the customer cost analysis, there is less intra-class subsidization occurring within a rate case.

Q. Mr. Knecht states on page 26 of his direct testimony that "I exclude uncollectibles costs from customer-related costs. Uncollectible costs are essentially a fee on customers who pay their bills to compensate the utility for those customers who do not. As these costs are essentially a tax, I deem it reasonable to recover these costs with volumetric charges within the small business classes." Do you agree?

A. No. By assigning 100% of uncollectible cost to the volumetric base rates for recovery essentially creates an intra-class subsidy to those lower use customers. Because the Customer charge is a portion of the customer's bills that becomes uncollectible, those who pay the Customer charge should help pay for the uncollectible accounts the charge generates. In contrast the universal service costs are costs incurred by recovering from residential service customers the portion of the residential CAP customer's bill not required to be paid by the CAP customer (ie. the volumetric portion).

Q. Does the Company agree with Mr. Knecht's proposed SGS2 and SDS/LGSS customer charges?

A. No. Similar to Mr. Cline, Mr. Knecht is using the customer cost study as a maximum charge to recover fixed cost through fixed recovery. The Company sees the study as an establishment of a minimum charge to recover fixed cost through the customer charge.

Q. **CAUSE witness Geller states on page 5 of his direct testimony "I discuss Columbia's proposed rate design, which seeks to recover a large portion of the residential cost of service through a fixed monthly customer charge." What portion of the residential cost of service is the Company seeking to recover through a fixed monthly customer charge?**

A. Average usage per customer for rate schedule RSS (Exhibit 103, Schedule 1 is 6.9Dth/Mo. Exhibit 111, Schedule 6, page 1 shows at 70 therms the total bill under proposed rates is $115.37, and the proposed customer charge is $19.33. Under current rates the customer charge is $16.75 and total bill is $100.77. The "large portion" of the bill that Mr. Geller speaks of is currently 16.62% of the total bill, and Columbia's proposed increase to the customer charge would result in the customer charge consisting of 16.75%of the total bill, a 0.13% change.

Q. **CAUSE witness Geller states on page 28 of his direct testimony "Columbia's proposal undermines the explicit goals of the Low income Usage Reduction Program (LIURP). The Commission's LIURP regulations explicitly provide that the program is intended to help low income customers to reduce their bills." Does Columbia's proposal undermine LIURP's intent to reduce low income customer bills?**

A. No. To illustrate why Mr. Geller's statement is inaccurate, I have calculated residential customer rates assuming all of the proposed revenue increase to the residential customers from the Customer Charge was shifted to the volumetric base rate. Exhibit 103, Schedule 8, Page 5 shows that the proposed rates for the residential rate class are a Customer charge of $19.33 and a volumetric base rate of $8.8796/Dth. If the proposed customer charge were to remain at the current rate of $16.75, $12,740,404 ($95,454,266 - $82,713,862) would shift from customer charge recovery to volumetric base revenue recovery. As a result the corresponding volumetric base rate would go up to $9.2473/Dth to make up the $12,740,404 shortfall. The average usage per LIURP customer was 154.7 Dth for the year 2020. As a comparison, the average usage per LIURP customer was 156.3 Dth for the year 2019.

Table MJB-3R below compares the amount billed using Columbia's proposed rate design compared to Mr. Geller's suggested no change in the customer charge. The results show that Mr. Geller's suggested change to Columbia's proposed rate design actually would charge LIURP customers $25.93 more ($1,631.56 - $1,605.63) in a year based on their 2020 average usage. Columbia's proposal clearly does not undermine LIURP's intent to reduce low income customer bills.

Table MJB-3R

	Columbia's Proposed Residential Rates	Geller's Proposed Customer Charge Change
Customer Charged Amount	$19.33 x 12 months = $231.96	$16.75 x 12 months = $201.00
Volumetric Charged Amount	$8.8796 * 154.7 = $1,373.67	$9.2473 * 154.7 = $1,430.56
Total Base Rate Charged Amount	$1,605.63	$1,631.56

Q. PWPTF witness Brady states on page 4 of his direct testimony, "Further, an increase in the fixed monthly charge, as requested by the Company, would negatively impact a customer's motive and ability to conserve energy. The company's proposal if granted would increase rates, discourage conservation and leave a customer with less ability to conserve energy and less ability to reduce their bills." Do you have any comments on his statement?

A. The customer will continue to have substantial incentive to conserve under the Company's proposed rates, as consumption charges still are increasing over current charges. The Company's proposal does not decrease commodity charges. If the Company does not increase the revenue requirement of the customer charge in this case, it will have to increase the volumetric base rate by the entire revenue requirement increase approved by the Commission. As stated above, that would change the residential customer charge from the proposed $19.33/month to the current $16.75/month and shift the entire amount of the approved revenue requirement to the volumetric rate, changing it from $8.8796/Dth to $9.2473/Dth. However, Table MJB-4R below shows at the residential average monthly usage of 70 therms (7.0 Dth) in this case, the customer's bill is essentially identical ($81.49 vs $81.48) under Columbia's proposed customer charge and Mr. Brady's proposed customer charge. Table MJB-5R shows the difference in the customer's monthly bill if the customer reduced his consumption by 1.35 Dth per month by replacing his furnace[1]. The results would be an additional $0.50 ($69.50 - $69.00) per month savings to the customer under Mr. Brady's proposal not to change the customer charge as compared to the Company's rate design.

Table MJB-4R

	Columbia's Proposed Residential Rates	Brady's Proposed Customer Charge Change
Customer Charged Amount	$19.33	$16.75
Volumetric Charged Amount	$8.8796 * 7.0 = $62.16	$9.2473 * 7.0 = $64.73
Total Base Rate Charged Amount	$81.49	$81.48

Table MJB-5R

	Columbia's Proposed Residential Rates	Brady's Proposed Customer Charge Change
Customer Charged Amount	$19.33	$16.75
Volumetric Charged Amount	$8.8796 * 5.65 = $50.17	$9.2473 * 5.65 = $52.25
Total Base Rate Charged Amount	$69.50	$69.00

Q. WPTF witness Brady states on page 6 of his direct testimony, "In a National Fuel Gas case (No. R-00061493) former Commissioner Cawley issued a statement while the case was pending concerning National Fuel Gas's ("NFG's") proposal to increase its fixed monthly customer charge.

[1] Exhibit MJB-1R shows an annual reduction of 16.2 Dth due to a furnace replacement. (16.2 Dth / 12 Months = 1.35 Dth per month). 7.0 Dth – 1.35 = 5.65 Dth.

That statement read in relevant part: "This proposed change raises important policy issues that affect this Commission's goals of promotion and encouragement of conservation of natural resources, including natural gas." Do you have any comments on his statement?

A. Witness Brady fails to provide the appropriate context for his quote. In the referenced case, NFG recommended a 72% increase in the monthly customer charge (from $12.00 to $20.64) where the overall increase to the residential class was 6.9%. (Oct. 31, 2006 Recommended Decision, p. 2) Unlike the large proposed increase to the customer charge in the NFG case, Columbia is proposing a proportional increase in the Customer charge so that there is not an intra-class shifting of revenue requirement within the residential rate class.

Q. Mr. Miezwa on page 16 states "Columbia's monthly Residential customer charge is already the highest in the Commonwealth. Therefore, I recommend that the existing $16.75 monthly charge be maintained." Do you agree?

A. Columbia's residential customer charge should be based on the fixed costs incurred by Columbia and approved by the Commission as recoverable through the Customer charge. Columbia's residential customer charge should not be determined by the cost of service of other LDC's in Pennsylvania. Even using the customer cost study that excludes mains cost, customer costs exceed the proposed customer charge. Customer costs continue to rise, as service lines, regulators and meters are replaced as part of infrastructure improvement. There has been no corresponding increase to residential customer charges in 8 years.

V. Revenue Normalization Adjustment ("RNA")

Q. On page 6 of his direct testimony, I&E witness Cline states three reasons for his recommendation to deny the Company's proposed RNA to be denied in this case on page 6 of his direct testimony. Please address each of his reasons.

A. Mr. Cline listed his reasons as follows. First, the Commission recently determined the RNA was unnecessary. Second, the policy statement cited by the Company does not allow Columbia to abandon the necessity to charge just and reasonable rates. Third, the use of the FPFTY already provides projected lower usage levels.

As for Mr. Cline's first reason, the Commission did not determine that the RNA was not necessary. The Commission stated the following in Docket No. R-2020-3018835, p. 264-265, Order entered February 19, 2021:

> The ALJ recommended that the Commission deny the RNA proposal. The ALJ reasoned that Columbia failed to prove the RNA Rider is needed and reasonable, or that the RNA Rider will result in rates that are just, reasonable and in the public interest. Further, the Company did not show its current rates and systems of revenue streams will fail to provide revenue stability. R.D. at 403.

It is clear that the ALJ stated that Columbia simply failed to prove the RNA was needed in that case. It is also to be noted that Columbia did not file any Exceptions to this issue in the 2020 case, and thus did not present full argument to the Commission on this issue.

Columbia's financial health directly relies upon its ability to recover the cost of service approved by the Commission through the base non-gas revenues upon which its base rates were previously established.

As customers conserve, the volumetric base rate recovers less base revenue than required to recover the Company's cost of service.

In months the WNA is not in effect there are still variances between actual and normal usage due solely to weather. As a result the volumetric base rate recovers either less or more base revenue than required to recover the Company's cost of service depending if actual weather is warmer or colder than normal.

If the BTU content in the gas consumed is either greater than or less than the BTU content used in the test year forecasted volumes, the volumetric base rate recovers either less or more base revenue than required to recover the Company's cost of service.

The RNA addresses these shortfalls of the volumetric base rate's ability to accomplish the objective of providing Columbia with a more reasonable opportunity to recover its fixed costs.

As for Mr. Cline's second reason, Mr. Cline assumes that Columbia is abandoning the necessity to charge just and reasonable rates by pointing to the Commission's Policy Statement on Alternative Ratemaking as adopted by the Commission at Docket No. M-2015-2518883. This is not the case. The base rates established by the Commission in the case will be just and reasonable. The RNA mechanism does not replace the billings of the base rates established in this case. The RNA does complement the residential rate design in this case to better ensure the revenue requirement assigned to the residential class is not over or under recovered due strictly to rate design. As for Mr. Cline's third reason, Mr. Cline suggests the core reason justifying an RNA is already being addressed by the use of the FPFTY and its projected lower usage levels. Although Mr. Cline's third reason may mitigate the need for an RNA it does not eliminate the need. To the extent that actual usage is greater than or less that what was forecasted for this case, the revenue collected will be different than what is approved by the Commission in this case. Even though "projected lower usage levels" are included in the billing determinates of the FPFTY, actual conservation, actual weather within the 3% WNA tolerance level, and weather variances outside the months the WNA is in effect all contribute to recovery variances caused by a volumetric base rate.

Q. OCA witness Miezwa addresses the 14 factors for consideration identified in the Commission's statement of policy on alternative rate

making. What comments do you have on Mr. Miezwa's responses to Columbia's claims?

A. Of the 14 factors, Mr. Miezwa agreed in principle with Columbia on 8 considerations. I will comment on those considerations where he differs.

> Consideration 1 Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
>
> COLUMBIA: Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.
>
> OCA: The Company's response does not indicate how the mechanism aligns revenues with cost causation as to fixed and variable costs.

The RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs. Residential base revenues consist of Customer Charge revenues and volumetric base rate revenues. The Customer charge recovers a portion of the Company's fixed monthly costs regardless of usage per customer changes and therefore do not contribute to the RNA rate. Volumetric base rate charges recover the fixed costs the Customer charge does not recover and all variable costs. To the extent the residential customer's monthly usage per customer differs from the benchmark established in this proceeding by the Commission, the Company will either over recover or under recover the fixed and variable costs through the variable base rates that the Company is authorized to bill by the Commission. The RNA is designed to recover/pass back the under/over amount charged by the variable base rates for recovery of those fixed and variable costs caused by the change in usage per customer. Therefore, the mechanism more closely aligns actual revenues to costs.

> Consideration 4 Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.
>
> COLUMBIA: Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.
>
> OCA: The RNA is only applicable to the Residential class and, therefore, does not affect interclass cost shifting. The Company's higher Residential customer charge proposal, which should be rejected, is unrelated to the RNA.

I disagree with the OCA. The Company's proposed higher residential customer charge is related to the RNA in that it reduces the amount of revenue subject to recovery through the RNA.

> Consideration 6 Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.
>
> COLUMBIA: Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.
>
> OCA: The RNA reduces the incentive for Residential customers to pursue energy efficiency programs. Base rate revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA.

Columbia disagrees with OCA's comment. When an individual residential customer decides to reduce their usage, the customer pays less to the Company through their volumetric charges. The shortfall of base revenue from the customer will be made up by the entire residential class, not just the residential customer that choose to conserve. This encourages other Residential customers to conserve as well.

> Consideration 8 Please explain how the RNA impacts customer rate stability principles.
>
> COLUMBIA: Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.
>
> OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The RNA will not change this standard.

Columbia was referring to mitigating the potential material rate adjustment caused when the billing determinants used in a rate case to design rates are materially different than the usage per customer experienced currently. Absent a RNA mechanism, the Company's only option is to file a rate case, to redesign the base rates to have a reasonable opportunity to recover the revenue requirement allowed by the Commission in the last rate case.

> Consideration 9 Please explain how weather impacts utility revenue under the RNA.
>
> COLUMBIA: The RNA, as proposed will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.
>
> OCA: Weather will not impact utility revenue under the RNA.

Columbia disagrees with the OCA, to the extent WNA does not address weather impact within the 3% band and to the extent it impacts weather outside the months WNA is in effect, weather will impact the RNA.

> Consideration 12 Please explain whether the RNA includes appropriate consumer protections.
>
> COLUMBIA: The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.
>
> OCA: The RNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony.

Mr. Miezwa states "The RNA does not include appropriate consumer protections" but gives no examples or support for his conclusion. The RNA does protect the consumer from the Company over collecting fixed cost through volumetric base rates due solely to rate design.

> Consideration 13 Please explain whether the RNA is understandable to customers.
>
> COLUMBIA: Columbia's RNA is not a unique concept to the regulated utility industry and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing an RNA tariff that clearly shows the detail how the mechanism works.
>
> OCA: Columbia has not provided any evidence that the RNA will be understandable to customers.

Columbia's affiliates in other states have successfully billed an RNA to residential customers in Virginia since 2010 and Maryland since 2013. It is Columbia's understanding that these billing have been done with minimal inquiries. Experience shows that customers do not have difficulty with the RNA.

Q. On page 22 of Mr. Mierzwa's direct testimony he states, "A new customer is likely to have purchased a more energy-efficient gas appliance than an average existing customer, and would have lower usage than an average customer, all else being equal. This would increase Columbia's earnings beyond what they would have been without Rider RNA because Columbia's margins would be based on average Residential customer margins." Is this statement accurate?

A. Based on Columbia's historical customer data, it is much more likely that just the opposite will occur. As it pertains to new customers, it is more likely that the RNA will decrease Columbia's earnings below what it would have been without Rider RNA. Mr. Mierzwa's premise that new customers are likely to have purchased a more energy-efficient gas appliance than an average existing customer, and would have lower usage than an average customer, all else being equal, does not account for the fact that new houses, although are on average more energy efficient than existing houses, they are also on average larger and therefore use more gas than existing houses. This is demonstrated on Exhibit 103 Schedule 1, Page 13, Lines 2 – 4, which shows 27,497,571.3 Dth and 4,023,298 bills for all customers (including new construction) on rate RSS. That equates to an average use per customer of 82.0 Dth (27,497,571.3 / 4,023,298 / 12 months). Exhibit 103, Schedule 3, Page 14, shows the forecasted usage per customer per month for new construction for the test year. Adding the monthly usage per customer results in 84.8 Dth (16.49 + 16.52 + 14.07 +

9.15 + 3.93 + 1.99 + 1.06 + 0.95 + 1.18 + 1.90 + 5.65 + 11.88). The data shows that new construction actually is expected to use 2.8 more Dth (84.8 – 82.0) per customer than the average for all RSS customers.

Q. On page 23 of Mr. Mierzwa's direct testimony he states "Rider RNA would unreasonably apply to those Residential customers whose usage is relatively constant over time." Do you agree?

A. No. Residential customers are subject to weather variations, to the extent WNA does not address weather impact within the 3% band and to the extent the customer's usage is impacted by weather outside the months WNA is in effect, even those residential customers who have a relatively constant usage over time will experience differences that will be picked up by the RNA. As for those residential customers who do not use gas for heat, those customers are already enjoying an intra-class subsidy by heat customers because a portion of their fixed costs are being collected through the volumetric base rate.

Q. On page 23 of Mr. Mierzwa's direct testimony he states "Conversion of a volumetric rate into rates that yield a given revenue, regardless of the amount of service purchased, converts Columbia's volumetric rate into take-or-pay billing feature". Do you agree?

A. No. If a residential customer does not use any gas he will not be charged a volumetric rate. This is not the case under a Take or Pay contract. If the residential class as a whole exceeds the weather normalized usage per customer established in the rate case by the Commission, each residential customer will receive a portion of the over recovery until the entire over collection is passed back. This is not the case under a Take or Pay contract. However, base rates are designed to offer the Company a reasonable opportunity to recover the authorized revenue requirement approved by the Commission. The RNA is a mechanism that helps ensure that the Company does not over recover or under recover due solely to rate design.

Q. On page 23 of Mr. Mierzwa's direct testimony he states, "The proposed Rider RNA operates to change rates, automatically, between rate cases, simply as a function of Residential distribution revenues being different from benchmark revenues due to factors other than weather. There is no review of Columbia's costs, or the volumes and attendant revenues from other customer classes that are not included under Rider RNA.". Do you agree?

A. No. Mr. Mierzwa is bringing up two separate circumstances that could occur whether the Company has an RNA for the residential class or not. Neither of these circumstances impacts the revenues Columbia receives through the RNA mechanism. The RNA is a mechanism that complements residential rate design to better ensure that Columbia has a reasonable opportunity to recover the revenue requirement approved by the Commission and to ensure customers a better opportunity not to be charged more than their cost of service established when current rates were designed.

Circumstance 1, Columbia's cost of service differs from the revenue requirement established by the commission in the last rate case. By design, any deviation of Columbia's cost to serve residential customers between rate cases has no impact to the RNA rate because the RNA is based on the Commission-approved revenue requirement. This is no different than if the Company has no RNA, base rate revenue recovery does not change between rate cases even if Columbia's cost of service does change.

Circumstance 2, Mr. Mierzwa alleges that if Residential usage per customer were to fall over time, while SGSS1/SCD1/SGDS1 deliveries increased, Columbia's Residential rates would be increased under Rider RNA with no recognition of the increased SGSS1/SCD1/SGDS1 distribution service revenues. Witness Mierzwa's statement is flawed for a few reasons. First, he assumes that lower residential use per customer implies lower distribution costs. However, a drop in average residential customer usage does not simply translate to lower costs for Columbia. On the contrary, he assumes that higher commercial usage is not associated with higher costs. It is possible that increased SGSS1/SCD1/SGDS1 usage could result in incremental costs, but the level of costs would depend upon the unique set of circumstances surrounding the load growth.

Q. On page 24 of Mr. Mierzwa's direct testimony he states "Columbia's current system of rates and charges, which include fixed monthly customer charges, a Purchased Gas Adjustment mechanism, a Weather

Normalization Adjustment, and a Distribution System Improvement Charge, provide for revenue stability and Columbia has not demonstrated that this stability is inadequate." Do you agree?

A. None of the mechanisms listed by the OCA address the revenue stability that Columbia's proposed RNA will provide. First, the Purchased Gas Adjustment mechanism does not help to stabilize revenues for distribution service. The gas cost adjustment is merely a tracker to collect costs related to the gas commodity. Second, Columbia's residential customer charge does not fully recover the fixed costs of service for residential customers. Please refer to Witness Notestone's testimony and schedules for detailed customer cost studies. Finally, the DSIC includes a cap equal to 5 percent of distribution revenues, which limits its usefulness for Columbia due to the Company's high rate of infrastructure replacement.

Q. Page 24 of Mr. Mierzwa's direct testimony he states "The Company proposed a similar Rider RNA in its last base rate case. In that proceeding the ALJ determined that the Company failed to prove that the RNA would result in rates that were just and reasonable, in the public interest, and the Company did not demonstrate that its current rates and systems of revenue streams failed to provided revenue stability. (Order at 264-265)." Do you have any comments?

A. First, no exceptions were filed, and therefore full arguments were not presented to the Commission in the last rate case. Second, the following additional evidence not shown in the last rate case demonstrate that its current rates and systems of revenue streams fail to provide revenue stability.

Again, the RNA is a mechanism that complements residential rate design to better ensure that Columbia has a reasonable opportunity to recover the revenue requirement approved by the Commission and to ensure Customers a better opportunity not to be charged more than their cost of service established when current rates were designed.

Table MJB-6R

Year	Basis	Residential Average Usage per Customer (Dth)
2014	Actual Normalized for Weather	91.3
2015	Actual Normalized for Weather	87.4
2016	Actual Normalized for Weather	86.7
2017	Actual Normalized for Weather	86.7
2018	Actual Normalized for Weather	88.2
2019	Actual Normalized for Weather	86.1
2020	Actual Normalized for Weather	84.2
2022	Projected	83.8

Table MJB-6R above shows residential usage per customer normalized for weather has consistently decreased over the past 7 years with the exception of 2018. Based on Columbia's demand forecast, it is expected to decrease in the rate year in this case as well. At current rates, a 1 Dth drop in usage amounts to an annual reduction of $2,814,932 in volumetric revenue to the Company (385,808 customers x $7.2962/Dth x 1Dth).

Q. Mr. Geller states on page 31 of his direct testimony, "I believe that Columbia's Rider RNA should be rejected. For the same reasons discussed at length above with regard to the fixed charge, I oppose implementation of Columbia's Rider RNA. In short, and without unnecessarily repeating my previous arguments, recovering revenue on a per customer basis, rather than a usage basis, strips low income households of the ability to control their bill through usage reduction and conservation efforts, and undermines the effectiveness of the Low Income Usage Reduction Program." Do you agree with Mr. Geller?

A. Mr. Geller's statement infers that the RNA "strips low income households of the ability to control their bill through usage reduction and conservation efforts" and that is simply not true. When an individual residential customer decides to reduce their usage through conservation, the customer pays less to the Company through their volumetric charges. The RNA does not change that. The shortfall of base revenue from the customer will be made up by the entire residential class, not just the residential customer that choose to conserve. Arguably this encourages other Residential customers to conserve as well. Refer to Exhibit MJB 1-R for calculations which demonstrate how a residential customer's reduced usage would result in savings on their bill with the Company's RNA proposal.

Q. Please explain the assumptions and calculations on Exhibit MJB 1-R.

A. Column 4 of Exhibit MJB-1R shows normalized usage for an average residential customer for the Fully Projected Future Test Year, 2022, as presented by Company Witness Danires on Exhibit No. 10, Schedule No. 2, page 8 of 8. Columns 5 through 8 are used to compute the monthly total bills for this typical residential customer. Row 13, column 8 shows a total annual residential bill of $1,311.32 using the Company's proposed residential rates. Columns 9 through 12 show three possible conservation measures that a residential customer could install. These measures include: a new furnace, attic insulation and wall insulation. Each conservation measure is associated with a hypothetical annual consumption reduction. On line 13, estimated annual bill savings corresponding with each of the conservation measures are computed. For example, if a residential customer installed a new, more efficient furnace, this analysis assumes that the customer could save 16.2 Dth annually. Given the proposed rates and including gas costs, this customer is estimated to save about $206 per year due to the installation of the new furnace.

Q. Will the RNA eliminate all bill savings associated with the installation of the new furnace?

A. No. Initially, the customer will experience the full savings of $206 per year. Therefore, the customer is able to associate a reduced bill with the installation of a conservation measure. On a lagged basis, the RNA may erode some of the savings. Similar to the normal rate case process, if consumption decreases, then the Company's costs would be spread over fewer volumes, so rates would increase. In this example, two hypothetical RNA rates were used to demonstrate how the RNA operates. Refer to lines 15 through 19 of Exhibit MJB-1R. Scenario A assumes an RNA rate of $0.25 per Dth. In the new furnace example, the residential customer's bill savings of $206 would be reduced by $17.15 in a future period. Scenario B uses a higher RNA rate and, as a result, the customer saves less in this scenario. However, in both scenarios, the customer that undertakes conservation efforts will continue to realize substantial savings, even after application of the RNA.

VI. Miscellaneous Service Revenue

Q. Mr. Cline recommends on pages 9 of his direct testimony that the Company's present rate revenue claim for miscellaneous service revenue be increased by $59,635 from negative $4,774 to $54,861. Do you agree with this recommendation?

A. Yes. Mr. Cline makes his recommendation because the Company made a one-time adjustment of $58,222.27 (debit) on the Company's books in August 2020. The Company agrees with Mr. Cline that an average amount of miscellaneous charge revenues received by the Company in August 2017, 2018, and 2019 (($14,682-$5,256+$3,536)/3=$4,321 should replace the amount of $-55,314.27 for the month of August 2020 (an increase of $59,635) is reasonable.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc

Potential Conservation Savings with RNA

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
			Normal	Customer	Distribution	Gas Supply	Total	Possible Conservation Measures*2			Total
line	Year	Month	Usage *1	Charge	Charge	Charge	Bill	Furnace	Attic	Wall	Sum of
			Dth	$19.33	$8.8796	$3.8512	[5]+[6]+[7]	Replaced	Insulation	Insulation	[9+10+11]
								Hypothetical Annual Dth Reduction			
								16.2	11.3	16.0	43.5
1	2022	Jan	16.49	$19.33	$146.44	$63.51	$229.29				
2	2022	Feb	16.52	$19.33	$146.73	$63.64	$229.69				
3	2022	Mar	14.07	$19.33	$124.94	$54.19	$198.46				
4	2022	Apr	9.15	$19.33	$81.27	$35.25	$135.85				
5	2022	May	3.93	$19.33	$34.91	$15.14	$69.38				
6	2022	Jun	1.99	$19.33	$17.70	$7.68	$44.71				
7	2022	Jul	1.06	$19.33	$9.42	$4.08	$32.83				
8	2022	Aug	0.95	$19.33	$8.44	$3.66	$31.43				
9	2022	Sep	1.18	$19.33	$10.45	$4.53	$34.32				
10	2022	Oct	1.90	$19.33	$16.85	$7.31	$43.48				
11	2022	Nov	5.65	$19.33	$50.21	$21.78	$91.32				
12	2022	Dec	11.88	$19.33	$105.48	$45.75	$170.56	Conservation Savings			
13	Total	Annual	84.78	$231.96	$752.84	$326.52	$1,311.32	$206.24	$143.86	$203.69	$553.79
14											
15	Scenario A - Hypothetical RNA Rate A =				$0.25	per Dth		$17.15	$18.37	$17.20	$10.32
16	Scenario A - Conservation Savings							$189.09	$125.49	$186.50	$543.47
17											
18	Scenario B - Hypothetical RNA Rate B =				$0.75	per Dth		$51.44	$55.11	$51.59	$30.96
19	Scenario B - Conservation Savings							$154.80	$88.75	$152.11	$522.83

Notes:
*1) Refer to Exhibit No. 10, Schedule No. 2, Page 8 of 8; Witness Bartos
*2) Columns [9], [10] & [11] show three possible conservation measures and related usage reductions.
Row 13 shows the bill reductions that would result and is computed as the distribution rate plus the gas cost rate multiplied by the assumed Dth savings.

COLUMBIA STATEMENT NO. 3-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	

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

July 30, 2021

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 Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as a Lead Regulatory Analyst.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your Rejoinder testimony?

A. I will respond to the surrebuttal testimony of Mr. Mierzwa, witness for the Office of Consumer Advocate ("OCA") and Mr. Knecht, witness for the Office of Small Business Advocate ("OSBA").

Q. Mr. Mierzwa discusses on page 19 of his direct testimony the Indiana Utility Regulatory Commission's (IURC) finding in re Citizens Gas & Coke Utility, IURC Cause No. 42767 (Oct. 19, 2006), when supporting his argument that the Peak & Average method of cost allocation should be relied upon. Do you have any comments about the use of this case and its relevance to Columbia's current case?

A. Yes. Starting at page 73, under "Discussion and Findings" the IURC describes how there were "three interclass cost-of-service studies for possible use in determining the appropriate proportion of Petitioner's total authorized revenue requirement to be assigned to each of its customer classes". The three studies were: 1) Citizens (the company) provided a study based on 100% of distribution mains cost based on "peak day" consumption and 0% of these costs on average annual consumption; 2) CIG (industrial intervenor) submitted an alternative cost-of-service study designed to correct the Company's study for what it believed to be an overstatement of costs assigned to the Large Volume customer class by allocating distribution mains based solely on peak day demand; and 3) OUCC (consumer advocate) submitted a Peak & Average cost-of-service study based on 20% of distribution mains cost based on "peak day" consumption and 80% of these costs on average annual consumption. The IURC described the OUCC study on page 74 as the "middle-of- the-road" approach.

The IURC rejected the Peak Responsibility method proposed by the company stating: "While we do not doubt that distribution mains must be constructed with peak demand in mind, distribution mains do not only serve customers on peak demand days". The IURC rejected the CIG's Peak Day method as well, stating: "We reject Mr. Phillips' cost of service study for the same reason. Allocation of distribution mains based solely on peak day demand may be advantageous to some industrial customers, but is still an undue burden on other rate classes".

I have two observations about this case. First, clearly this was a case about the merits of solely utilizing a Peak Responsibility method of allocating mains compared to a Peak & Average method. Columbia did not file nor did it advocate for the Pennsylvania Public Utility Commission to allow Columbia to use the Peak Responsibility as the sole basis of allocating revenue requirement in this case. Second, the IURC was not presented with a minimum system (Customer/Demand) method of allocating distribution mains in the Citizens case. Therefore, IURC relied on what it called a "middle-of-the-road" approach to allocate the distribution mains by rejecting the Peak Responsibility method in favor of the Peak & Average method.

Q. On page 20 of his direct testimony, Mr. Mierzwa discusses the Illinois Commerce Commission's ("ICC") finding in Re Central Illinois Public Service Company or CIPS and Union Electric Company or UE Case No. 02-0798, 03-0008, 03-0009 (2003) when supporting his argument that the Peak & Average method of cost allocation should be relied upon. Do you have any comments about the use of this case and its relevance to Columbia's current case?

A. Yes. On page 20 of his direct testimony, Mr. Mierzwa provides a lengthy quote from page 67 of the final order in the CIPS and UE case supporting the Peak & Average study. However, what is also of important is what the ICC concluded just above the quote on page 67 of the order. Specifically:

> "At issue is which allocation method most appropriately assigns transmission and distribution demand costs to the 'cost causer'. Each of the methods advocated in this proceeding consider in some manner the costs associated with peak demand and average demand. Use of NCP demand and the A&E method

> result in greater emphasis on peak demand than does use of the A&P method. The Commission is faced with placing the proper emphasis on peak demand."

The ICC states quite clearly that only the Average & Excess and the Average & Peak methods were presented in this case and that the only issue was to determine the "proper emphasis on peak demand".

Columbia did not file nor does it advocate here for the Commission to allow Columbia to use the A&E method as the basis for allocating revenue requirement in this case. The ICC was not presented with a minimum system (Customer/Demand) method of allocating distribution mains in the CIPS and UE case. Because the only methods presented in the CIPS and UE case advocated cost allocation considering peak demand and average demand, the ICC chose the method it determined properly emphasized peak demand.

Q. Is Columbia recommending that the Commission consider adopting a method other than the Peak & Average Study in setting rates in this case?

A. No. The goal of an allocated cost of service study is to fairly and reasonably assign the total company revenue requirement established in the case to the rate classes that cause the incurrence of the costs.

As stated in my rebuttal testimony, the Company recognizes this Commission's preference for the use of the Peak and Average study, and therefore, the Company used the Peak and Average study as the primary guide for the allocation of the proposed revenue increase in this case. While the Company believes the use of the three studies is appropriate, absent further guidance from the Commission, it has concluded that the Peak and Average study should be used as the primary guide. However, the Company does not believe that basing the revenue allocation in this case entirely on the Peak & Average Study would produce a reasonable result, particularly with respect to allocation of mains cost to the LDS/LGSS class.

In each of the cases cited by OCA Witness Mierzwa where the Commission has accepted the Peak & Average method the Commission has always pointed out the shortcomings of the absence of any other method of allocation offered by the utility as the basis of their decision to accept the Peak & Average method.

Q. Mr. Knecht states in his surrebuttal testimony his opinion of how demand-related costs should be recovered in rates. Do you agree with Mr. Knecht's opinion?

A. No. On page 10 of Mr. Knecht's surrebuttal he surmises correctly "It is possible that Witness Bell is arguing that the costs that are classified as "demand related" in the ACOSS are "fixed costs," and that these costs are better recovered in a fixed customer charge". He goes on to say "I respectfully disagree with that line of reasoning. Costs that are classified as demand-related in the Company's ACOSS will, over the longer term, vary with customer peak demands. Since it is probably not cost effective to recover these costs with a demand charge for smaller customers, the question is whether the customer charge or the volumetric charge is a better proxy for demand charge. Using a customer charge would imply that customers have the same level of peak demand regardless of annual consumption, a nonsensical hypothesis. Using the commodity charge to recover demand-related costs implies that peak demands rise in proportion to annual consumption, an assumption that is much more reasonable. Thus, recovering costs that are classified as demand-related with a commodity charge is much more consistent with cost causation than using a customer charge".

I do agree with Mr. Knecht that it is probably not cost effective to recover demand-related costs with a demand charge for smaller customers. It would require daily meter readings for each customer and Columbia would have to bill the customer the demand charge for each day of the monthly billing cycle based on the customer's daily meter reading.

I also agree with Mr. Knecht that because it is probably not cost effective to recover these costs with a demand charge for smaller customers, the question is whether the customer charge or the volumetric charge is a better proxy for demand charge. This is where I respectfully disagree with Mr. Knecht. As for the residential rate class, even the customers with the largest peak day demand can easily be served by a minimum sized main. Because the capacity requirements are essentially the same (i.e., minimum size main), the costs are similar and therefore it is appropriate to recover similar demand related fixed costs for the residential customer through the fixed monthly customer charge. The alternative that Mr. Knecht suggests, would recover a different amount of demand related fixed costs each month based on the residential customer's meter reading usage. So for example, a residential customer using 10 Dth in a month would pay twice as much as a residential customer using 5 Dth even though both residential customers have the same minimum capacity requirements and therefore the same demand related cost. The same can be said at least for the SGS customers using < 6,440 therms annually whose capacity requirements are similar to the residential class.

As for the remaining rate classes, Columbia has multiple levels of customer charges within the rate classes to limit the variance of peak day loads and of the associated cost. Similar to the residential and SGS rate classes, the remaining classes represent groups of customers where the capacity requirements are similar within the group and therefore it would be more appropriate to recover the demand cost within a customer charge than a volumetric throughput rate. .

Q. Mr. Mierzwa sites a National Association of Home Builders ("NAHB") study that found "Newer homes are larger, but over the long run the effects of increased efficiency more than offsets the extra square footage". Do you have any comments?

A. Mr. Mierza has provided no context in which this quote was made or what is meant by "over the long run". The NAHB acknowledges that "Newer homes are larger", however the quote seems to imply that because of energy efficiency, newer homes use less gas. One thing is certain, new customer bills are expected to make up 0.08% (3,534 / (4,023,298 + 662,355)[1] of total bills for the residential rate class for the test

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[1] Exhibit 103 Schedule 4, Page 14, Line 17 / (Exhibit 103, Schedule 1, Page 13, Line 2 + Exhibit 103, Schedule

year. If their usage turns out to be either slightly above or slightly below the benchmark established by this rate case, the impact should not influence the decision to adopt the Revenue Normalization Adjustment mechanism.

Q. Does this complete your Prepared Rejoinder Testimony?

A. Yes, it does.

1, Page 15, Line 2)

C. NOTESTONE

COLUMBIA STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
CHAD NOTESTONE
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

Q. Please state your name and business address.

A. Chad Notestone, my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am a Lead Regulatory Analyst 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. I am responsible for the preparation and support of various rate related regulatory studies, such as allocated cost of service ("ACOS") studies, lead lag studies, and the development of revenue used in support of rate proceedings for the subsidiary companies of NiSource.

Q. What is your educational and professional background?

A. I attended Ohio University and received a Bachelor of Business Administration degree in Finance in 2006 and a Master of Business Administration degree in 2013. I began my career with NCSC in 2007 as a Regulatory Analyst. I was promoted to Senior Regulatory Analyst in 2009 and then to Lead Regulatory Analyst in 2013. I became a Manager of Regulatory Studies in 2015. I began my current role in 2021. In addition to my work experience, I have attended a variety of public utility accounting and ratemaking seminars.

Q. Have you previously testified before this Commission?

A. Yes. I provided testimony in Docket No. R-2020-3018835. I have also provided testimony before the State Corporation Commission of Virginia, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, and the Kentucky Public Service Commission.

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

A. I am sponsoring Columbia's Allocated Cost of Service ("ACOS") studies and the proposed rate design shown in Exhibit 103, Schedule 8. In addition, I will be supporting the Company's residential rate structure proposals regarding the Revenue Normalization Adjustment ("RNA"). As required by Section 53.53IV[1], 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 IV 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 as required by Section 53.53IV. The Company's ACOS studies are presented in Exhibit No. 111 and a detailed description of the methodologies are

[1] 52 Pa Code § 53.51, et. seq.

included in this testimony. The ACOS studies are based on the fully projected future test year ending December 31, 2022.

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 has in the past submitted that the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation. However, Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case.

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. The average study with its equal weighting of the two studies, provides the Company, the parties and the Commission with another set of returns that can be used as a guide in revenue allocation. In other words, the average study serves as another tool that can be used by the parties to inform the revenue allocation in setting cost based rates.

Q. Could you provide a list of the schedules, and attachments you are sponsoring through your testimony?

A. Yes. the table below lists all the schedules and attachments that I am sponsoring.

Schedule/Attachment	**Description**
Exh. No. 11	ACOS Studies
Exh. No. 111, Schedule No. 1	Customer-Demand Study
Exh. No. 111, Schedule No. 2	Peak and Average Study
Exh. No. 111, Schedule No. 3	Average Study
Exh. No. 111, Schedule Nos. 5 & 6	Bill Comparisons
Exh No. 103, Schedule No. 8	Proposed Revenue Allocation, Rates
Statement No. 11, Exhibit CEN-1	Development of Allocation Factors
Statement No. 11, Exhibit CEN-2	Calculation of Allocation Factors
Statement No. 11, Exhibit CEN-3	Factor Selection and Rationale
Statement No. 11, Exhibit CEN-4	Intra-Class Adjustment of Storage Carrying Costs
Statement No. 11, Exhibit CEN-5	ACOS Study Return Results
Statement No. 11, Exhibit CEN-6	Gas Procurement Charge Calc.
Statement No. 11, Exhibit CEN-7	Benchmark Distribution Revenue per Bill
Statement No. 11, Exhibit CEN-8	Revenue Normalization Adjustment for Peak Period
Statement No. 11, Exhibit CEN-9	Revenue Normalization Adjustment for Off Peak Period

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 both contain 13 pages. The customer-demand study contains the customer charge studies, which I will be discussing later in my testimony, and which are shown 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 forfeited discounts, 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 C&I customers whose annual usage is less than 6,440 therms. SGSS, SCD and SGDS were combined and presented in Column F of each study for C&I 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 sensitivity, 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. Large Distribution Service ("LDS") and the upper band of Large General Sales Service ("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. Costs and revenues attributable to customers taking service under the Flexible Rate Provisions and Negotiated Contract Service tariffs (combined and identified as "FLEX") are presented in Column J[2].

Q. How were Total Company O&M expenses determined by Federal Energy Regulatory Commission ("FERC") account in the allocated cost of service studies?

A. O&M expenses for the fully projected future test year presented in Exhibit 104 were based on cost element data, i.e., labor, benefits, insurance, etc. The ACOS 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, 2020).

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. Beginning with the 2012 rate case (Docket No. R-2012-2321748), the Company separated the low pressure and two inch (2") mains and allocated 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 performed a similar separation of mains by operating pressure in

[2] Per paragraph No. 46 of the Joint Petition for Partial Settlement at Docket No. R-2018-2647557.

every rate case since 2012 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 low pressure and higher pressure systems in this case?

A. No. Mains cost allocation factors produced from the separation of mains by pressure study are not materially different than the mains allocators produced from simply using total mains (i.e. no separation of mains by operating pressure). This is largely due to Columbia's pipe replacement efforts over the last several years which have had the effect of phasing out its low pressure mains. Columbia's low pressure mains are typically older and constructed of cast iron or steel pipe. Over time, Columbia has been replacing this low pressure pipe with plastic pipe operated under higher pressures. Therefore, the results produced from the separated mains pressure study have become less meaningful as the system has become more homogenous in terms of operating pressure.

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 the majority of the Company's gross plant investment and distribution O&M expenses, excluding gas costs. The allocation of these items significantly influences the outcome of the studies. In addition, many other elements of O&M 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, Line 8 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 attributable to low income residential customers.

Q. How did you handle Uncollectibles related to unbundling?

A. Columbia utilizes three systems to bill customers, 1) DIS that bills monthly read customers for either sales or Choice Transportation service, 2) Gas Measurement Billing ("GMB") that bills monthly read customers for either sales or Choice distribution service, and 3) Gas Transportation System ("GTS") 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 were 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 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 based on the meter's maximum cubic feet per hour gas flow ("CFH"), 0-500 CFH, 501-1000 CFH, 1001-1,500 CFH, and over 1,500 CFH. 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, 2020 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 CEN-1 attached to this testimony, entitled "Development of Allocation Factors", I provided a description for all allocation factors used for the studies. In Exhibit CEN-2, I included all calculations of all allocation factors. And in Exhibit CEN-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 through 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.

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. I will discuss the Company's proposed customer charges later in my testimony.

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. I prepared a study, included as Exhibit CEN-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. Please describe the rate design principles that the Company considered when developing the proposed revenue allocation and rates.

A. The principles that were used to guide the development of the Company's rate design include: efficiency, simplicity, continuity, fairness, and earnings stability. An efficient rate design provides accurate price signals and, thus, an accurate basis for consumers' decisions and provides the Company 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 study in determining customer 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.

Q. Please state the basis for the Company's proposed revenue allocation among the rate classes.

A. Consistent with the goal of continuity, Columbia seeks to move base rates closer to the allocated cost of service for each customer class gradually, so as to avoid rate shock to any particular rate class. The cost to serve each rate class is defined through the allocated cost of service study.

Q. How were the results of the cost allocation 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 customer groups. The peak and average study and the customer demand study (Columbia Statement No. 7) provides information about class cost relationships and helps establish a "zone of reasonableness" from which an appropriate revenue allocation and rate design can be derived. For this case, Columbia used the peak and average study as the primary study to establish class rates of return at present and proposed rates. The peak and average study was given primary consideration given the Commission's ruling on the matter in Columbia's 2020 rate case. However, Columbia believes the results from the other two studies can still be useful as another reference point in guiding the allocation of the proposed revenue increase. The results of the cost allocation studies support the Company's proposed rate schedules. Details concerning the application of the cost study results in the proposed rate design are provided later in this testimony.

Q. What are the results of the allocated cost of service studies at current rates?

A. Exhibit CEN-5, attached to my testimony, shows the class-level return indices for each of the ACOS studies. Return indices compare individual class returns to the overall total company return. A return index is calculated by dividing the class return by the total company return. The total company return index will always be 1.00. The closer individual classes return is to the total company return, the closer its index will be to 1.00 and to parity. The term "parity" in this context means that the class return and the total company return are equal.

The return index for the residential class ranges from 0.72 under the Customer/Demand study to 1.26 under the Peak & Average study. The average ACOS study produces a residential return index of 0.95.

The SGS1/SCD1/SGD1 return indices are 1.08 for the Peak & Average study, 1.14 for the Customer/Demand study and 1.11 for the average ACOS study.

The SGS2/SCD2/SGD2 return indices are 1.14 for the Peak & Average study, 2.87 for the Customer/Demand study and 1.77 for the average ACOS study.

The SDS/LGSS return indices are 0.95 for the Peak & Average study, 3.92 for the Customer/Demand study and 1.81 for the average ACOS study.

The LDS/LGSS return indices are 0.17 for the Peak & Average study, 3.60 for the Customer/Demand study, and 0.90 for the average ACOS study.

The return index for the Main line Distribution Service ("MLDS") class 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 30.41.

The FLEX return indices are -0.84 for the Peak & Average study, -0.31 for the Customer/Demand study, and -0.72 for the average ACOS study.

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, through a goal of equal rates of return by class, 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 minimize 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. First, Columbia's proposed rate increases for the various rate classes cause a movement of the unitized returns toward parity (unitized return of 1.00) for each of the rate classes but with no rate class yet reaching parity. Secondly, the range of base rate revenue increase percentages for any class was not to exceed 1.5 times the total system average increase of 19.91% (see Exhibit 103, Schedule No. 8, Page 1, Lines 21 through 37).

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 4, Line 19 reflects the following allocations: 68.93% of the overall increase is applied to the residential class; 8.61% of the overall increase is applied to the SGS1/SCD1/SGDS1 class; 9.29% of the overall increase is applied to the SGS2/SCD2/SGDS2 class; 7.14% of the overall increase is applied to the SDS/LGS class; 6.01% of the overall increase is applied to the LDS/LGS class; 0.00% of the overall increase is applied to MLDS customers; and 0.02% of the overall increase is applied to the FLEX customers.

Exhibit 103, Schedule 8, Page 4, Lines 5 and 6 shows the movement toward parity produced by Columbia's proposed revenue allocation using the peak and average ACOS Study. The movement toward parity (unitized return of 1.00) measures each class's return versus the total company return under current and proposed rates.

Q. Please explain why the revenue allocation to Flex was limited to the revenue generated by increased customer charges.

A. Flex agreements are individually negotiated contracts with a customer who has provided a sworn affidavit that a lower rate is required to meet competition from an alternate fuel. Per the Flexible Rate Provisions of Columbia's tariff, the customer charge is not eligible for downward adjustment, and is not negotiable. The customer charges that flex customers are charged are set under the rate schedule in which the customer is receiving service under[3].

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 flex rates, the Company may lose these customers to alternatives. Without the revenues from flex rate customers, the Company's non-flex customers would be assigned additional fixed cost recovery responsibility and their rates would increase.

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 1.00 and a total company required rate of return of 7.88%)

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[3] Columbia Gas of Pennsylvania Tariff, Supplement No. 221 to Tariff Gas – Pa. PUC. No. 9 Sixth Revised Sheet No. 68.

but recognizes a move to full parity of 1.00 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 revenue through the customer charges for each of the rate classes. As explained later in this testimony, the proposed residential customer charge does not fully recover the ACOS determined level of customer costs.

Q. Why is there a need to increase the percent of base rate recovery through the customer charge now that Columbia has a Weather Normalization Adjustment ("WNA") mechanism?

A. The WNA normalizes the impact of weather on the recovery of residential usage based base revenue (outside a 3% band) during the winter months that 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 customers, 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. However, the WNA mechanism is not intended to address usage fluctuations that are attributable to conservation efforts or other changing consumption characteristics, intra-class subsidization of fixed cost recovery, weather effects of consumption outside the five winter months that the WNA is in effect, the weather effects of consumption within the 3% WNA band, or weather effects of consumption for rate classes not covered by the WNA. It is for these reasons that it is important for the customer charges to recover an increased percent of base rate revenue recovery.

Q. What are the new base rates proposed for residential customers?

A. Columbia proposes to increase the monthly residential customer charge from $16.75 to $19.33. The remaining residential revenue increase was assigned to the volumetric charge for a resulting rate of $8.8796 per Dth.

Q. How did Columbia determine a residential customer charge of $19.33?

A. Exhibit No. 111, Schedule 1, page 25, shows that the minimum monthly customer-based cost excluding distribution mains costs for the residential class is $24.23. Columbia's current charge of $16.75 was established in its 2012 rate case. Since then, residential customer based costs excluding costs related to distribution mains improvements has increased 43%, but the customer charge has not increased. Columbia's proposed monthly customer charge of $19.33 reflects the $16.75 established in 2012 adjusted for inflation. The proposed charge of $19.33 is well below the minimum cost justified rate of $24.23 supported by the customer charge study excluding mains costs.

Q. Describe the new base rates proposed for Small General Service customers consuming less than or equal to 6,440 therms annually.

A. Columbia proposes to increase the customer charge from $26.00 to $31.50. The increased customer charge is proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates. Exhibit No. 111, Schedule No. 1, pages 16 and 25 shows that the minimum customer costs for this rate class range from $27.03 (excluding mains) to $69.08 (including mains). Columbia's customer charge proposal of $31.50 falls near the bottom end of the range of customer based costs. The remaining revenue is recovered through the volumetric base rates of $6.5197/Dth for SGSS1/SCD1 service and $6.4348/Dth for SGDS1 service.

Q. What are the customer based costs for the Small General Service customers using between 6,440 and 64,400 therms annually?

A. The proposed SGSS2/SCD2/SGDS2 customer charge for customers whose usage is between 6,440 therms and 64,400 therms is $66.00. The increased customer charge is proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates. The volumetric charge will be $5.4799/Dth for SGSS/SCD service and $5.3949/Dth for SGDS service.

Q. Please explain the why the SGDS customers in the two rate classes above have a different volumetric charge than the SGSS and SCD customers in those rate classes.

A. Consistent with previous base rate proceedings, the Columbia 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. As shown on Exhibit CEN-4, Columbia has re-allocated $202,594 of storage working capital costs from the SGDS class to SGSS/SCD. This intra-class re-allocation is shown on Lines 16 of Exhibit 103, Schedule 8, Pages 7 and 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 $335.00 and the proposed customer charge for customers whose usage is between 110,000 therms and 540,000 therms is $1,104.00. The increase in customer charges is proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates.

The volumetric base rate will be $4.1250/Dth for SDS/LGSS customers whose usage is between 64,400 therms and 110,000 therms and $3.8566/Dth for SDS/LGSS for customers whose usage is between 110,000 therms and 540,000 therms.

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

A. The table below shows the proposed customer charges for the LDS/LGSS rate class, which reflect an increase proportional to the base revenue increase for the rate class.

Annual Usage Levels	Proposed Cust. Charge
> 540,000 to ≤ 1,074,000 Therms	$2,919.00
> 1,074,000 to ≤ 3,400,000 Therms	$4,540.00
> 3,400,000 to ≤ 7,500,000 Therms	$8,755.00
> 7,500,000 Therms	$12,971.00

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 9, Line 26 spread among the LDS/LGSS annual usage groups?

A. The volumetric base 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 28 through 31).

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

A. Refer to Exhibit No. 103, Schedule No. 8.

Q. What are the class-level bill impacts resulting from the Company's proposal?

A. The class average bill impacts are shown on Exhibit No. 103, Schedule No. 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 1-10. Residential Sales Service is shown on page 1, and pages 2-10 provide graphs for commercial and industrial customers.

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

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

Q. Has the Company performed bill impact analyses at various usage levels for commercial and industrial customers?

A. Yes. Refer to Exhibit No. 111, Schedule No. 6, pages 2-10. These pages provide monthly bill impacts for Small General Sales Service and Large General Sales Service customers at various usage levels.

Q. Is the Company proposing any changes to the Rider WNA – Weather Normalization Adjustment?

A. Not changes, per se, but the Company is proposing to continue the Rider WNA until a final order is entered in the Company's first rate case filed after May 31, 2026.

Q. Please describe the WNA and explain why the Company is proposing to extend it in this proceeding.

A. Rider WNA adjusts a residential customer's monthly charges based on the actual temperature experienced during the month. Under the WNA, the Company and customers are protected, in part, from usage variations due to weather. The WNA adjusts only the temperature-sensitive portion of customers' bills to reflect normal weather levels. By distinguishing between base load and temperature-sensitive load, each customer's bill is calculated to mitigate the undesirable impacts of warmer than normal or colder than normal weather. Rider WNA was approved in the Company's 2012 base rate proceeding as a pilot program, and is set to expire upon the issuance of a final order in the Company's first rate case filed after May 31, 2020, which will be the order issued in this proceeding, unless the Company obtains Commission approval to continue the WNA. Columbia's nearly eight years of experience with the WNA demonstrates that this rate design mechanism provides stability by adjusting bills for colder and warmer than normal weather, and that the WNA is effective at providing customer-specific billing adjustments in a timely manner. As such, the Company seeks to continue the Rider WNA until a final order is entered in the Company's first rate case filed after May 31, 2026.

Q. What other rate design proposal is Columbia making in this case?

A. Columbia is proposing the implementation of a Revenue Normalization Adjustment ("RNA") for the residential class in this case. The RNA provides a benchmark distribution revenue level regardless of changes in customers' actual usage levels. Rider RNA would adjust actual non-gas distribution revenue for the non-CAP residential customer class. Columbia's proposed RNA is designed to "break the link" between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers.

Q. How does the RNA promote revenue stabilization?

A. The RNA promotes revenue stabilization because it relies on distribution revenue per customer, not usage per customer. Once the Company's revenue requirement is set through a base rate case proceeding, then a benchmark revenue per residential customer is established. Through Rider RNA, the Company would refund any amount over the benchmark revenue per residential customer and would be allowed to collect any amount below the benchmark revenue per customer. Hence, the RNA "breaks the link" between residential non-gas revenue and gas consumed by non-CAP residential customers.

Q. How does the proposed RNA align with the Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883?

A. Each rate consideration identified in the Statement of Policy is listed below along with the relevant effect the proposed RNA has on each rate consideration:

1. Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
   a. Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.
2. Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.
   a. Columbia's RNA proposal has no identifiable effect on the capacity utilization of the residential class.

3. Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.
   a. Columbia's RNA benchmark revenue includes the anticipated volumetric base revenue derived from the fully projected test year consumption.
4. Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.
   a. Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.
5. Please explain how the RNA limits or eliminates disincentives for the promotion of efficiency programs.
   a. Reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between level of throughput and base revenue recoveries is broken with the implementation of the RNA.
6. Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.
   a. Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.

7. Please explain how the RNA impacts low-income customers and support consumer assistance programs.
   a. Columbia's proposed RNA only applies to non-CAP customers.
8. Please explain how the RNA impacts customer rate stability principles.
   a. Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.
9. Please explain how weather impacts utility revenue under the RNA.
   a. The RNA, as proposed will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.
10. Please explain how the RNA impacts the frequency of rate case filings and affects regulatory lag.
    a. The RNA is designed to mitigate the over or under recovery of the residential cost of service in this case. Future rate cases would still be required to capture cost of service changes that occur beyond the residential class and the fully projected test year in this case.
11. Please explain if the RNA interacts with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system

improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).

a. Columbia's proposed RNA only applies to the recovery of costs included in determination of the residential base revenue requirement.

12. Please explain whether the RNA includes appropriate consumer protections.

a. The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.

13. Please explain whether the RNA is understandable to customers.

a. Columbia's RNA is not a unique concept to the regulated utility industry and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing a RNA tariff that clearly shows the detail how the mechanism works.

14. Please explain how the RNA will support improvements in utility reliability.

a. Columbia's cost of service reflects the investments and costs made for the continued enhancement of the safety and reliability of its system. The RNA reduces the volatility concerning the recovery of those costs.

Q. How frequently does the Company propose to compute Rider RNA and adjust residential customers' bills?

A. Columbia proposes to calculate Rider RNA and adjust residential customers' bills every six months based upon a comparison of benchmark distribution revenue to actual distribution billed revenue. Under the Company's proposal, Rider RNA would be credited or charged to all non-CAP residential bills (i.e., Rate RSS – Residential Sales Service, and Rate RDS – Residential Distribution Service (CHOICE)).

Q. Describe the time periods used to calculate the proposed benchmark base revenues for non-CAP residential customers.

A. The proposed benchmark distribution revenues will be computed for two separate six-month periods. The first time period, or "Peak Period," includes billing cycles for October through March, and the second time period, or "Off-Peak Period," includes billing cycles for April through September. Although, the Company considered monthly RNA rate adjustments, Peak and Off-Peak Periods were selected to minimize rate fluctuations for customers. These specific six-month periods were selected to align Rider RNA rate changes with the gas cost rate changes. This helps to minimize the number of times customers' rates are changed annually.

Q. Please describe the timing of charging Rider RNA on residential customers' bills.

A. The RNA computed for the Peak Period would be applied to the next Peak Period. Likewise, the RNA computed for the Off-Peak Period would be applied to the next Off-Peak Period. For example, the RNA computed for the Peak Period beginning with October 2022 billing cycles and ending with March 2023 billing cycles would be applied to residential customers' bills for the period beginning with October 2023 billing cycles and ending with March 2024 billing cycles. By lagging the adjustment until the next corresponding time period, the Company moderates the impact of any adjustment, because Peak Period adjustments are applied to Peak Period volumes.

Q. Explain the calculation of the Peak and Off-Peak Benchmark Distribution Revenue per Bill ("BDRB").

A. Columbia proposes to set Peak and Off-Peak BDRBs using weather normalized test year revenues for the FPFTY approved in this proceeding, divided by the number of residential bills for the applicable six-month period.

Q. How would the BDRB be utilized for Rider RNA?

A. For each period, the difference between the BDRB and the Actual Distribution Revenue per Bill ("ADRB") would be multiplied by the Actual Number of non-CAP Residential Bills ("ANB") to compute base revenues to be collected or refunded to non-CAP residential customers.

Q. What are the Peak and Off-Peak BDRB levels proposed by Columbia?

A. Refer to Exhibit CEN-7 for the calculation of the BDRBs proposed by the Company for the Peak and Off-Peak Periods. The BDRBs are based upon the Company's filed for revenue requirement. Exhibit CEN-7 shows the following BDRB levels for Rider RNA:

	Peak BDRB		Off-Peak BDRB
January	$162.08	April	$98.31
February	$162.18	May	$53.41
March	$140.73	June	$36.78
October	$36.10	July	$28.79
November	$67.94	August	$27.97
December	$121.46	September	$29.94
6-Month Total	$690.49		$275.20

Q. Would the Company need to adjust the BDRB levels after a final revenue requirement is approved by the Commission?

A. Yes. The proposed BDRB levels would need to be revised for the final revenue requirement approved by the Commission.

Q. When does the Company propose to reset the BDRB levels?

A. New BDRB levels for the Peak and Off-Peak Periods would be established with each base rate case filing.

Q. Has the Company filed a tariff for its RNA proposal?

A. Yes. The Company's RNA Rider is set forth on Page Nos. 144 and 145 of Columbia's proposed tariff (Columbia Statement No. 12).

Q. Can you please explain how the RNA and WNA work together and why both are needed?

A. Although Rider RNA could serve the purpose of adjusting revenues for normal weather, Rider WNA does it more efficiently, for a few reasons. First, the WNA applies to each individual customer's consumption and usage patterns. This results in no cross-subsidization as a result of adjusting bills for normal weather. The WNA is billed in real time, so there is no lag in refund or recovery due to weather variances from normal. This means that there is no need for a reconciliation adjustment with Rider WNA. Additionally, by recovering or refunding the impact of weather through the WNA, the RNA would be mitigated to recovering distribution revenues that deviate from test year benchmark distribution revenues exclusive of distribution revenues adjusted through Rider WNA.

Q. How will the WNA and RNA mechanisms operate to avoid double-counting adjustments in the RNA?

A. BDRB levels are based upon normal weather and ADRB will include monthly Rider WNA adjustments. Thus, the RNA will only capture any difference net of weather.

Q. Have Columbia affiliates successfully implemented RNA with an existing WNA in place in other jurisdictions?

A. Yes. Similar alternative rate design mechanisms have been implemented in other jurisdictions. Columbia Gas of Maryland and Columbia Gas of Virginia have implemented RNA mechanisms in addition to an existing WNA mechanism.

Experience from those other jurisdictions has been considered in the context of proposing a residential rate design for Columbia in this case.

Q. When does the Company propose to implement the RNA?

A. Columbia proposes to implement the RNA with January 2022 billing cycles. This initial Peak Period RNA ("RNAp") would become effective with October 2022 billing cycles.

Q. What additional filing(s) would occur related to Rider RNA?

A. The Company would submit two filings related to Rider RNA per year. The Peak Period RNA Filing would be submitted 1 day prior to the effective date of the Peak RNA adjustment and the Off-Peak Period RNA Filing would be filed 1 day prior to the effective date of the Off-Peak RNA adjustment.

Q. Please present Columbia's proposed RNA formula.

A. The Company's proposed RNA formula for the Peak Period is shown below:

$$\text{Peak Period:} \quad RNAp = \frac{[ANBp \times (BDRBp - ADRBp)]}{FTp}$$

<u>RNA</u> is the Revenue Normalization Adjustment for non-CAP residential customers for the applicable period.

<u>BDRB</u> is the Benchmark Distribution Revenue per Bill for non-CAP residential customers for the applicable period.

<u>ADRB</u> is the Actual Distribution Revenue per Bill for non-CAP residential customers for the applicable period. ADRB includes Rider WNA adjustments in the applicable months.

ANB is the Actual Number of non-CAP residential Bills for the applicable period. ANB will be computed using a six-month average.

FT is the Forecast Therms for residential non-CAP customers for the six-month period that the RNA will be applied.

Q. Is the calculation of the Off-Peak Period RNA similar to the Peak Period RNA?

A. Yes. The equations are the same for the six-month Off-Peak RNA ("RNAo") calculations.

Q. Does Columbia propose to apply interest to the RNA balances?

A. Yes. Refunds to customers shall be made with interest and recoveries from customers shall include interest at the prime rate for commercial borrowing in effect 60 days prior to the tariff filing and as reported in a publicly available source identified by the Commission or at an interest rate which may be established by the Commission by regulation.

Q. How does the Company plan to implement the RNA in the middle of the Peak Period?

A. For the initial Peak Period RNA, the Company will compute benchmark revenues using three billing months: January, February and March. The actual distribution revenues and actual number of non-CAP bills would also include only January, February and March of 2022.

Q. Please provide sample RNA calculations for the initial Peak and Off-Peak periods.

A. Please refer to Exhibits CEN-8 and CEN-9 for sample RNA calculations for the initial Peak and Off-Peak Periods. Exhibit CEN-8 shows the calculation of the RNAp adjustment for a three-month period, because Columbia is proposing to begin tracking for the RNA beginning with billing month January 2022. Line 3 of Exhibit CEN-8 shows the monthly BDRBp levels proposed in this proceeding. The ADRBp would be input on line 7. For this sample calculation, ADRBp amounts were assumed for illustrative purposes, because actual information for January through March 2022 is not available. Line 9 shows the subtraction of lines 3 and 7. The resulting difference is multiplied by an illustrative ANBp for each month to compute revenue to be assigned to the RNAp (line 16) for collection in the next Peak Period. Line 18 shows forecasted Dth for the months of October 2022 through March 2023. The RNAp rate effective for October 2022 billing cycles through March 2023 billing cycles is calculated on line 20. Exhibit CEN-9 shows the same computations for the initial Off-Peak Period, including the months of April through September. The initial RNAo would be effective with April 2023 billing cycles.

Q. Does the RNA mechanism result in all non-CAP residential customers paying the same total distribution charge?

A. It does not. All non-CAP residential customers will continue to pay a customer charge and a volumetric rate. Through the RNA mechanism, an adjustment rate is calculated and applied to each non-CAP residential customer’s usage in a future period. Thus, the RNA mechanism helps to balance revenue stability while allowing customers to experience any benefit from controlling their usage and conserving.

Q. Does the Company propose to reconcile the RNA collections or credits in future time periods?

A. Yes. Collections will be tracked and credited or charged in the next corresponding Peak or Off-Peak RNA Filing.

Q. Has the Company proposed any changes to the calculation of quarterly Rider USP as a result of the proposed RNA?

A. No. Because Columbia's proposed RNA does not apply to CAP customers, changes to Rider USP are not needed.

Q. Why not apply the RNA to CAP customers?

A. CAP customers' payments are defined by their ability to pay. Incorporating a charge or credit related to RNA would ultimately flow into the Rider USP charge. Columbia concluded that this added unnecessary complexity to the RNA.

Q. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

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 CEN-2, Page 1.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending December 31, 2022 are the basis for Factor No. 2. See Exhibit CEN-2, Page 2.

Factor No. 3- Throughput Excluding MDS

Factor No. 3 represents the throughput quantities excluding MDS quantities for the twelve months ending December 31, 2022. See Exhibit CEN-2, Page 2.

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, 2022 using the applicable Gas Cost Recovery ("GCR") rates. See Exhibit CEN-2, Page 3.

Factor No. 5 - Composite of Factors No. 1 and Throughput

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities for the historic test year ended November 30, 2020 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 CEN-2 Pages 4 for the detail development of Factor No. 5.

Factor No. 6 - Average Number of Customers

Customers for each month of the twelve months ending December 31, 2022 were averaged and used to develop Factor No. 6. See Exhibit CEN-2, Page 5.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2020 to small usage customers through the Company's Distributive Information System ("DIS"). See Exhibit CEN-2, Page 6.

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2022 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems. See Exhibit CEN-2, Page 7.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2020. See Exhibit CEN-2, Page 8.

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, 2020. See Exhibit CEN-2, Page 9.

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 CEN-2, Page 10.

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 CEN-2, Page 13.

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

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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 CEN-2, Page 14.

Factor No. 14 – Composite Direct Plant – Accts 376 & 380

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 CEN-2, Page 15.

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 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 CEN-2, Page 19.

Factor No. 16 – Direct Assignment – Meters

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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 in 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 in 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 CEN-2, Page 20.

Factor No. 17 – Direct Assignment - Ind M&R

Individual measuring stations are identified in 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 CEN-2 Page 29.

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

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Line 19 Account 871 - Distribution Load Dispatch

Line 20 Account 874 - Mains & Services

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 CEN-2, Page 30.

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 35) less Gas Purchased Cost (Page 7, Line 1), Uncollectibles (Page 8, Lines 5, 6, & 7), USP Rider (Page 8, Line 8) and A&G Expenses (Page 8, Line 34). See Exhibit CEN-2, Page 31.

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 CEN-2, Page 32.

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Aminimum 2” system approach is used to determine the customer related cost component of mains. 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 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.

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 CEN-2, Page 33.

Factor No. 22 –Average Factor Nos. 5 & 20

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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 CEN-2, Page 34.

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 CEN-2, Page 35.

Factor No. 24 - Labor

Factor No. 24 is based on the allocation of labor charges with the various Federal Energy Regulatory Committee (“FERC”) Accounts. The labor dollars allocated to the various rate classes are summed and converted to percentages to create Factor No. 24. See Exhibit CEN-2, Page 36.

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, 2022. See Exhibit CEN-2, Page 2.

Factor No. 26 – Other Automated Metering Devices

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Factor No. 26 is developed based on customers eligible for telemetry metering services pursuant to Tariff Supplement 296, which includes customers taking service under rate schedules SDS, LDS and MLDS. See Exhibit CEN-2, Page 37.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2020-2021)

LINE NO.	Rate	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX [2]	Total
1	RCC/RC2	30,900	0	0	0	0	0	30,900
2	RS	328,600	0	0	0	0	0	328,600
3	RTC	105,500	0	0	0	0	0	105,500
4	LG1	0	0	0	4,800	0	0	4,800
5	LG2	0	0	0	7,500	0	0	7,500
6	LG3	0	0	0	0	200	0	200
6	SC2	0	0	17,000	0	0	0	17,000
7	SCC	0	20,700	0	0	0	0	20,700
8	SG2	0	0	51,600	0	0	0	51,600
9	SGS	0	54,500	0	0	0	0	54,500
10	SG4	0	0	800	0	0	0	800
11	TAG1	0	400	0	0	0	0	400
12	TAG2	0	0	5,900	0	0	0	5,900
13	TAG5	0	2,100	0	0	0	0	2,100
14	TAG6	0	0	25,700	0	0	0	25,700
15	TI4	0	0	0	13,000	0	0	13,000
16	TI8	0	0	0	0	14,600	0	14,600
17	TIB	0	0	0	30,600	0	0	30,600
18	TIF	0	0	0	0	21,800	0	21,800
19	TIG	0	0	0	0	9,100	0	9,100
20	FLEX	0	0	0	0	0	45,200	45,200
21	Total	465,000	77,700	101,000	55,900	45,700	45,200	790,500
22	MDS							18,400
23	Other (Co. Used)							2,500
24	Total							811,400
25	**ALLOCATOR #1**	**58.824%**	**9.829%**	**12.777%**	**7.071%**	**5.781%**	**5.718%**	**100.000%**

[1] Includes Firm and Non-Firm Service. Volumes in MDth/Day.
[2] Excludes MDS FLEX

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS 2, 3, & 25
THROUGHPUT EXCLUDING TRANSPORTATION, THROUGHPUT EXCLUDING MDS

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	TOTAL
	Sales								
1	RSS	27,497,571	-	-	-	-	-	-	27,497,571
2	RDGSS	-	-	-	-	-	-	-	-
3	RCC 1/	-	-	-	-	-	-	-	-
4	SGSS1	-	3,901,994	-	-	-	-	-	3,901,994
5	SGSS2	-	-	3,903,397	-	-	-	-	3,903,397
6	NSS/MLSS-1	-	-	-	-	-	69,600	-	69,600
7	LGSS1 & 2	-	-	-	993,014	-	-	-	993,014
8	LGSS3 & greater	-	-	-	-	-	-	-	-
	Transportation								
8	RDS	7,145,892	-	-	-	-	-	-	7,145,892
9	RDGDS	-	-	-	-	-	-	-	-
10	SCD1	-	1,491,506	-	-	-	-	-	1,491,506
11	SCD2	-	-	1,611,987	-	-	-	-	1,611,987
12	SGDS1	-	262,006	-	-	-	-	-	262,006
13	SGDS2	-	-	3,477,755	-	-	-	-	3,477,755
14	SDS	-	-	-	6,501,837	-	-	-	6,501,837
15	LDS	-	-	-	-	11,116,014	-	-	11,116,014
16	FLEX							8,720,420	8,720,420
17	MLDS	-	-	-	-	-	2,326,000	-	2,326,000
18	Total Throughput Excl. Trans. (Allocator 2)	27,497,571	3,901,994	3,903,397	993,014	-	69,600	-	36,365,577
19	**ALLOCATOR #2**	75.614%	10.730%	10.734%	2.731%	0.000%	0.191%	0.000%	
20	Total Throughput Excl. MDS (Allocator 3)	34,643,463	5,655,506	8,993,139	7,494,851	11,116,014		8,720,420	76,623,393
21	**ALLOCATOR # 3**	45.213%	7.381%	11.737%	9.781%	14.507%		11.381%	
22	**Sales and Choice Volume**	34,643,463	5,393,499	5,515,384	993,014	-	69,600	-	46,614,961
23	**ALLOCATOR #25**	74.319%	11.570%	11.832%	2.130%	0.000%	0.149%	0.000%	

NOTE: **1/ RCC rate schedule is for CAP customers. They can be either CHOICE or Sales.**

SOURCE: Exhibit No. 103, Schedule 3.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 4
GAS PURCHASE EXPENSE

LINE NO.		RSS/RDS GAS COST	SGS/DS-1 GAS COST	SGS/DS-2 GAS COST	SDS/LGSS GAS COST	LDS/LGSS GAS COST	MDS GAS COST	FLEX GAS COST	TOTAL
1	RSS	105,898,647	-	-			-	-	105,898,647
2	RCC	4,419,163	-	-			-	-	4,419,163
3	RDS	9,298,091	-	-			-	-	9,298,091
4	SGSS	-	15,027,359	15,032,763			-	-	30,060,122
5	NSS	-	-	-			220,393	-	220,393
6	SCD	-	2,863,094	3,094,370			-	-	5,957,464
7	SGDS	-	107,731	1,582,399			-	-	1,690,130
8	LGS	-	-	-	3,655,831	168,466	-	-	3,824,297
9	TOTAL	119,615,901	17,998,184	19,709,532	3,655,831	168,466	220,393	-	161,368,307
10	**ALLOCATOR #4**	74.126%	11.153%	12.214%	2.266%	0.104%	0.137%	0.000%	

SOURCE: Exhibit No. 103, Schedule 1.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2020

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: C. E. Notestone

Line No.	Description	Alloc	Total Company	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX
1	Throughput Volumes (Total Company excl MDS)		76,623,393	34,643,463	5,655,506	8,993,139	7,494,851	11,116,014	8,720,420
2	Percent Throughput		100.000%	45.213%	7.381%	11.737%	9.781%	14.507%	11.381%
3	Throughput Component		50.000%	22.604%	3.691%	5.869%	4.891%	7.254%	5.691%
4	Design Day Volumes (Total Company excl MDS)		790,500	465,000	77,700	101,000	55,900	45,700	45,200
5	Percent Design Day Volumes		100.000%	58.824%	9.829%	12.777%	7.071%	5.781%	5.718%
6	Demand Component		50.000%	29.410%	4.915%	6.389%	3.536%	2.891%	2.859%
7	Demand/Commodity Factor		100.000%	52.014%	8.606%	12.258%	8.427%	10.145%	8.550%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 6
AVERAGE NO. OF CUSTOMERS

TARIFF RATE SCHEDULES	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	[1] Total No of Bills (Incl Final)	Final Bills
RSS	3,971,707	0	0	0	0	0	0	4,023,298	51,591
RCC	249,497	0	0	0	0	0	0	252,488	2,991
RDS	657,985	0	0	0	0	0	0	662,355	4,370
RDGDS	0	0	0	0	0	0	0	0	0
SGSS1	0	265,279	0	0	0	0	0	266,855	1,576
SGSS2	0	0	34,745	0	0	0	0	34,842	97
NSS	0	0	0	0	0	12	0	12	0
SCD1	0	97,259	0	0	0	0	0	97,598	339
SCD2	0	0	14,809	0	0	0	0	14,843	34
SGDS1	0	11,227	0	0	0	0	0	11,250	23
SGDS2	0	0	18,574	0	0	0	0	18,642	68
LGSS1 & 2	0	0	0	1,032	0	0	0	1,035	3
LGSS3 & greater	0	0	0	0	24	0	0	24	0
SDS	0	0	0	4,872	0	0	0	4,884	12
LDS	0	0	0	0	864	0	0	864	0
FLEX	0	0	0	0	0	0	276	276	0
MLDS	0	0	0	0	0	84	0	84	0
Total Number of Bills	4,879,189	373,765	68,128	5,904	888	96	276	5,389,350	61,104
Average Number of Customers	406,599	31,147	5,677	492	74	8	23		
ALLOCATOR #6	91.571%	7.015%	1.279%	0.111%	0.017%	0.002%	0.005%		

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	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		Total	Residential	Commercial					
1	DIS Billed Net Charge-offs - Sales Only	3,896,308.30	3,665,123.95	231,184.35					
2	DIS Billed Revenue - Comm/Ind Sales Only	76,780,323		43,057,756	33,722,567	0	0	0	0
3	Percent	100.000%		56.079%	43.921%	0.000%	0.000%	0.000%	0.000%
4	Allocated DIS Billed Sales Net Charge-offs	3,896,308.30	3,665,123.95	129,645.87	101,538.48	0.00	0.00	0.00	0.00
		Total	Residential	Commercial					
5	DIS Billed Net Charge-offs - Choice Only	390,688.60	323,130.63	67,557.97					
6	DIS Billed Revenue - Comm/Ind Choice Only	44,372,178		15,227,231	29,144,947	0	0	0	0
7	Percent	100.000%		34.317%	65.683%	0.000%	0.000%	0.000%	0.000%
8	Allocated DIS Billed Choice Net Charge-offs	390,688.60	323,130.63	23,183.87	44,374.10	0.00	0.00	0.00	0.00
9	Total DIS Billed Net Charge-offs	4,286,996.90	3,988,254.58	152,829.74	145,912.58	0.00	0.00	0.00	0.00
10	**ALLOCATOR #7**	100.000%	93.031%	3.565%	3.404%	0.000%	0.000%	0.000%	0.000%

EXHIBIT CEN-2
ALLOC 8

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 8
CURRENT GMB/GTS REVENUE

LINE NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	CURRENT GMB/GTS REVENUE	51,107,511	-	21,264	1,299,102	23,877,893	21,202,603	1,329,287	3,377,362
2	**ALLOCATOR #8**	100.000%	0.000%	0.042%	2.542%	46.721%	41.486%	2.601%	6.608%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 9
DIRECT ASSIGNMENT - CUSTOMER DEPOSITS

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	TOTAL
1	Residential Unlisted	33,701	-	-	-	-	33,701
2	RS	1,614,229	-	-	-	-	1,614,229
3	RTC	119,037	-	-	-	-	119,037
4	Commercial Unlisted	-	22,086	-	-	-	22,086
5	SCC	-	26,310	-	-	-	26,310
	LG1	-	-	-	-		-
	LG2	-	-	-	-	-	-
6	SC2	-	-	5,716	-	-	5,716
7	SGS	-	611,745	-	-	-	611,745
8	SGT	-	15,327	-	-	-	15,327
	SG3		-		-	-	-
9	SG2	-	-	42,668	-	-	42,668
10	TOTAL	1,766,967	675,468	48,384	-	-	2,490,819
11	**ALLOCATOR #9**	70.940%	27.118%	1.942%	0.000%	0.000%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 10
FORFEITED DISCOUNTS

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	487.00	FORFEITED DISCOUNTS - DIS	950,984	753,791	91,041	98,199	3,284	4,646	-	23
2	487.00	FORFEITED DISCOUNTS - GMB & GTS	79,828	-	33	2,029	37,297	33,118	2,076	5,275
3		TOTAL CURRENT SALES AND TRANSPORTATION REVENUE	1,030,812	753,791	91,074	100,228	40,581	37,764	2,076	5,298
4		**ALLOCATOR #10**	100.000%	73.126%	8.835%	9.723%	3.937%	3.664%	0.201%	0.514%

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	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	374.10	LAND - CITY GATE & M/L IND M&R	21,944	16,803	1,822	1,436	724	583	-	575
2	374.20	LAND - OTHER DISTRIBUTION	3,361,100	2,573,695	279,106	219,984	110,883	89,304	-	88,128
3	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	73,021	7,919	6,241	3,146	2,534	-	2,500
4	374.40	LAND RIGHTS - OTHER DISTRIBUTION	3,851,518	2,949,223	319,830	252,082	127,062	102,335	-	100,987
5	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBU	-	-	-	-	-	-	-	-
6	374.41	LAND RIGHTS - OTHER DISTRIBUTION LO	13	10	1	1	0	0	-	0
7	374.50	RIGHTS OF WAY	3,233,171	2,475,736	268,483	211,611	106,662	85,905	-	84,774
8	374.50	DIRECT - RIGHTS OF WAY	-	-	-	-	-	-	-	-
9	375.20	M & R STRUCTURES - CITY GATE	7,026	5,380	584	460	232	187	-	184
10	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	3,072	333	263	132	107	-	105
11	375.40	M & R STRUCTURES - REGULATING	6,397,121	4,898,468	531,217	418,692	211,041	169,972	-	167,733
12	375.40	DIRECT - M & R STRUCTURES - REGULAT	27,126	-	-	-	-	-	24,324	2,802
13	375.60	M & R STRUCTURES - DIST. IND. M & R	86,228	-	1,376	11,962	29,251	29,297	-	14,342
14	375.80	M & R STRUCTURES - COMMUNICATION	16,515	12,646	1,371	1,081	545	439	-	433
15	376.00	MAINS	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	-	62,316,811
16	376.00	DIRECT - MAINS - MDS	142,006	-	-	-	-	-	71,014	70,992
17	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	-	616,576
18	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	-	1,008,070
19	376.30	DIRECT - MAINS-BARE STEEL	80,803	-	-	-	-	-	80,803	-
20	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	-	2,539
21	378.10	M & R EQUIP - GENERAL	1,444,656	1,106,217	119,964	94,553	47,659	38,385	-	37,879
22	378.20	M & R EQUIP - GENERAL - REGULATING	131,630,413	100,793,356	10,930,590	8,615,211	4,342,487	3,497,420	-	3,451,349
23	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	-	-	-	-	-	-	678,970
24	378.30	M & R EQUIP - LOCAL GAS PURCHASES	437,493	335,002	36,329	28,634	14,433	11,624	-	11,471
25	379.10	M & R EQUIP - CITY GATE	136,417	104,458	11,328	8,929	4,500	3,625	-	3,577
26	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(345)	(37)	(29)	(15)	(12)	-	(12)
27	380.00	SERVICES	790,447,259	719,915,650	56,912,203	11,145,306	1,659,939	482,173	-	331,988
28	380.00	DIRECT - SERVICES	1,966	-	-	-	-	-	561	1,405
29	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
30	381.00	METERS	42,969,482	32,988,531	6,144,636	3,405,331	333,443	78,205	3,008	16,328
31	381.10	AUTOMATIC METER READING	24,684,074	18,950,457	3,529,823	1,956,213	191,548	44,925	1,728	9,380
32	381.10	AUTOMATIC METER READING - OTHER	404,440	-	-	-	333,307	50,130	5,420	15,583
33	382.00	METER INSTALLATIONS	44,125,107	33,875,727	6,309,890	3,496,915	342,411	80,308	3,089	16,768
34	383.00	HOUSE REGULATORS	16,515,236	15,106,816	1,122,871	252,518	27,085	4,294	496	1,156
35	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,187,606	236,931	53,282	5,715	906	105	244
36	385.00	IND M&R EQUIPMENT	7,448,547	-	118,879	1,033,262	2,526,771	2,530,718	-	1,238,917
37	385.00	DIRECT - IND M&R EQUIPMENT	493,521	-	-	-	-	-	434,968	58,553
38	385.10	IND M&R EQUIPMENT - LG VOLUME	1,037,970	-	16,566	143,987	352,111	352,661	-	172,646
39		TOTAL	3,522,012,747	2,806,794,736	289,415,723	190,974,040	91,225,400	72,453,581	625,514	70,523,754
40		**ALLOCATOR #11**	100.000%	79.694%	8.217%	5.422%	2.590%	2.057%	0.018%	2.002%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	301.00	Organizational Costs	100,099							
2	302.21	Franchises/Consent, Perpetual	26,216							
3	303.00	Misc Intangible Plant	4,809,062							
4	303.30	Misc Software	58,452,700							
5	305.00	Structures & Improvements	0							
6	301-303	TOTAL INTANGIBLE PLANT	63,388,078	50,516,495	5,208,598	3,436,902	1,641,751	1,303,893	11,410	1,269,029
7	350.10	Land	23,882							
8	350.20	Rights of Way	1,932							
9	351.20	Compressor Station Structures	3,250,037							
10	352.01	Wells Construction	738,941							
11	352.02	Wells Equipment	168,032							
12	352.10	Storage Leasehold and Rights	139,442							
13	352.12	Other Leases	67,498							
14	353.00	Lines	389,345							
15	354.00	Compressor Station Equipment	948,177							
16	355.00	Measuring & Regulating Equipment	104,477							
17	362.00	Gas Holders	0							
18	362.10	Environmental Remediation	0							
18	350-362	TOTAL UNDERGROUND STORAGE	5,831,763	4,334,108	674,735	690,014	124,217	0	8,689	0
19	374.10	LAND - CITY GATE & M/L IND M&R	21,944	16,803	1,822	1,436	724	583	0	575
20	374.20	LAND - OTHER DISTRIBUTION	3,361,100	2,573,695	279,106	219,984	110,883	89,304	0	88,128
21	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	73,021	7,919	6,241	3,146	2,534	0	2,500
22	374.40	LAND RIGHTS - OTHER DISTRIBUTION	3,851,518	2,949,223	319,830	252,082	127,062	102,335	0	100,987
23	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	0	0	0	0	0	0	0	0
24	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	10	1	1	0	0	0	0
25	374.50	RIGHTS OF WAY	3,233,171	2,475,736	268,483	211,611	106,662	85,905	0	84,774
26	374.50	DIRECT - RIGHTS OF WAY	0	0	0	0	0	0	0	0
27	375.20	M & R STRUCTURES - CITY GATE	7,026	5,380	584	460	232	187	0	184
28	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	3,072	333	263	132	107	0	105
29	375.40	M & R STRUCTURES - REGULATING	6,397,121	4,898,468	531,217	418,692	211,041	169,972	0	167,733
30	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	0	0	0	0	0	24,324	2,802
31	375.60	M & R STRUCTURES - DIST. IND. M & R	86,228	0	1,376	11,962	29,251	29,297	0	14,342
32	375.70	M & R STRUCTURES - OTHER	32,767,270	26,113,548	2,692,487	1,776,641	848,672	674,023	5,898	656,001
33	375.71	M & R STRUCTURES - OTHER LEASED	6,293,269	5,015,358	517,118	341,221	162,996	129,453	1,133	125,991
34	375.80	M & R STRUCTURES - COMMUNICATION	16,515	12,646	1,371	1,081	545	439	0	433
35	376.00	MAINS	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	0	62,316,811
36	376.00	DIRECT - MAINS - MDS	142,006	0	0	0	0	0	71,014	70,992
37	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	0	616,576

EXHIBIT CEN-2
ALLOC 12

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		DISTRIBUTION PLANT								
1	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	0	1,008,070
2	376.30	DIRECT - MAINS-BARE STEEL	80,803	0	0	0	0	0	80,803	0
3	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	0	2,539
4	378.10	M & R EQUIP - GENERAL	1,444,656	1,106,217	119,964	94,553	47,659	38,385	0	37,879
5	378.20	M & R EQUIP - GENERAL - REGULATING	131,630,413	100,793,356	10,930,590	8,615,211	4,342,487	3,497,420	0	3,451,349
6	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	0	0	0	0	0	0	678,970
7	378.30	M & R EQUIP - LOCAL GAS PURCHASES	437,493	335,002	36,329	28,634	14,433	11,624	0	11,471
8	379.10	M & R EQUIP - CITY GATE	136,417	104,458	11,328	8,929	4,500	3,625	0	3,577
9	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(345)	(37)	(29)	(15)	(12)	0	(12)
10	380.00	SERVICES	790,447,259	719,915,650	56,912,203	11,145,306	1,659,939	482,173	0	331,988
11	380.00	DIRECT - SERVICES	1,966	0	0	0	0	0	561	1,405
12	380.12	CSL REPLACEMENT	0	0	0	0	0	0	0	0
13	381.00	METERS	42,969,482	32,988,531	6,144,636	3,405,331	333,443	78,205	3,008	16,328
14	381.10	AUTOMATIC METER READING	24,684,074	18,950,457	3,529,823	1,956,213	191,548	44,925	1,728	9,380
15	381.10	AUTOMATIC METER READING - OTHER	404,440	0	0	0	333,307	50,130	5,420	15,583
16	382.00	METER INSTALLATIONS	44,125,107	33,875,727	6,309,890	3,496,915	342,411	80,308	3,089	16,768
17	383.00	HOUSE REGULATORS	16,515,236	15,106,816	1,122,871	252,518	27,085	4,294	496	1,156
18	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,187,606	236,931	53,282	5,715	906	105	244
19	385.00	IND M&R EQUIPMENT	7,448,547	0	118,879	1,033,262	2,526,771	2,530,718	0	1,238,917
20	385.00	DIRECT - IND M&R EQUIPMENT	493,521	0	0	0	0	0	434,968	58,553
21	385.10	IND M&R EQUIPMENT - LG VOLUME	1,037,970	0	16,566	143,987	352,111	352,661	0	172,646
22	387.10	OTHER EQUIP DISTRIBUTION	19,450	15,501	1,598	1,055	504	400	4	389
23	387.20	OTHER EQUIP ODORIZATION	117,248	93,439	9,634	6,357	3,037	2,412	21	2,347
24	387.42	OTHER EQUIP RADIO	119,609	95,321	9,828	6,485	3,098	2,460	22	2,395
25	387.44	OTHER EQUIP COMMUNICATION	623,932	497,237	51,269	33,830	16,160	12,834	112	12,491
26	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	10,630,871	8,472,167	873,539	576,406	275,340	218,677	1,914	212,830
27	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER	69,585	0	0	0	0	0	69,585	0
28	387.50	GPS EQUIPMENT	2,201,372	1,754,362	180,887	119,358	57,016	45,282	396	44,072
29	374-387	TOTAL DISTRIBUTION	3,574,855,354	2,848,851,668	293,752,082	193,835,393	92,592,221	73,539,122	704,598	71,580,270

EXHIBIT CEN-2
ALLOC 12

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		GENERAL PLANT								
1	389.20	Land Rights	0							
2	390.10	Str, Communications	49,821							
3	391.10	OF&E Unspecified	2,020,141							
4	391.11	OF&E Data Handling Equipment	91,304							
5	391.12	OF&E Information Systems	367,128							
6	391.20	OF&E Air Cond Equip	3,007							
7	392.20	Trans Eq Trailers > $1,000	14,787							
8	392.21	Trans Eq Trailers $1,000 or >	10,830							
9	393.00	Stores Equipment	0							
10	394.10	Tools, Garage & Service Eq	60,884							
11	394.11	CNG Equip - Stationary	(26,345)							
12	394.12	CNG Equip - Portable	179,308							
13	394.20	Shop Equipment	35,454							
14	394.30	Tools & Other	17,452,652							
15	394.31	High Pressure Stopping	10,847							
16	395.00	Laboratory Equipment, Gas	264,921							
17	396.00	Power Operated Equipment	948,698							
18	397.00	Communication Equipment	0							
19	397.10	Communication Equipment-Telephone	0							
20	397.20	Communication Equipment-Radio	0							
21	397.40	Communication Equipment-Other	0							
22	397.50	Communication Equipment-Telemetering	2,921,116							
23	398.00	Miscellaneous Equipment	944,905							
24	389-398	TOTAL GENERAL PLANT	25,349,458	20,201,997	2,082,965	1,374,448	656,551	521,438	4,563	507,496
25		TOTAL	3,669,424,654	2,923,904,268	301,718,381	199,336,757	95,014,740	75,364,453	729,260	73,356,795
		ALLOCATOR #12		79.684%	8.222%	5.432%	2.589%	2.054%	0.020%	1.999%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 13
DIRECT PLANT - MAINS

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	376.00	MAINS	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	-	62,316,811
2	376.00	DIRECT - MAINS - MDS	142,006	-	-	-	-	-	71,014	70,992
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	-	616,576
4	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	-	1,008,070
5	376.30	DIRECT - MAINS-BARE STEE	80,803	-	-	-	-	-	80,803	-
6	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	-	2,539
7		TOTAL	2,438,971,723	1,867,423,206	202,513,710	159,616,116	80,454,327	64,797,559	151,817	64,014,988
		ALLOCATOR #13	100.000%	76.566%	8.303%	6.544%	3.299%	2.657%	0.006%	2.625%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 14
COMPOSITE DIRECT PLANT - ACCOUNTS 376 & 380

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	376.00	MAINS	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	-	62,316,811
2	376.00	DIRECT - MAINS - MDS	142,006	-	-	-	-	-	71,014	70,992
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	-	616,576
4	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	-	1,008,070
5	376.30	DIRECT - MAINS-BARE STEEL	80,803	-	-	-	-	-	80,803	-
6	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	-	2,539
7	380.00	SERVICES	790,447,259	719,915,650	56,912,203	11,145,306	1,659,939	482,173	-	331,988
8	380.00	DIRECT - SERVICES	1,966	-	-	-	-	-	561	1,405
9	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
10		TOTAL	3,229,420,948	2,587,338,856	259,425,912	170,761,423	82,114,266	65,279,731	152,378	64,348,381
11		**ALLOCATOR #14**	100.000%	80.117%	8.033%	5.288%	2.543%	2.021%	0.005%	1.993%

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2020

Billing Rate	Rate Case Rate	Classification	BLANK	P	S	*	+	Total	Average Unit Cost	Total Cost	Key
802	FLEX MDS	8"	0	0	0	1	1	2	7,771.80	15,543.60	8028"
808	FLEX	4"	0	0	0	1	0	1	3,882.87	3,882.87	8084"
809	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8096"
809	FLEX	8"	0	0	0	1	0	1	7,771.80	7,771.80	8098"
810	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8104"
810	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8106"
816	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	816UNDER 3"
831	FLEX MDS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	831UNDER 3"
833	FLEX	8"	0	0	0	0	1	1	7,771.80	7,771.80	8338"
840	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8404"
840	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	840UNDER 3"
845	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8454"
846	FLEX	6"	0	0	0	0	1	1	4,996.93	4,996.93	8466"
846	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	846UNDER 3"
847	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8474"
848	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	848UNDER 3"
857	FLEX	3"	1	0	0	0	0	1	583.46	583.46	8573"
868	FLEX	UNDER 3"	0	0	0	1	1	2	1,216.88	2,433.76	868UNDER 3"
873	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8736"
875	FLEX	12"	1	0	0	0	0	1	69,826.82	69,826.82	87512"
875	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8756"
875	FLEX	8"	0	0	0	1	0	1	7,771.80	7,771.80	8758"
876	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	876UNDER 3"
877	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	877UNDER 3"
879	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	879UNDER 3"
880	FLEX	12"	1	0	0	0	0	1	69,826.82	69,826.82	88012"
881	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8814"
881	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	881UNDER 3"
EDSTIB1	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	EDSTIB1UNDER 3"
LG1	SDS/LGSS	3"	4	0	0	2	0	6	583.46	3,500.76	LG13"
LG1	SDS/LGSS	4"	7	0	0	0	1	8	3,882.87	31,062.96	LG14"
LG1	SDS/LGSS	6"	0	0	0	1	0	1	4,996.93	4,996.93	LG16"
LG1	SDS/LGSS	UNDER 3"	24	0	0	3	3	30	1,216.88	36,506.40	LG1UNDER 3"
LG2	SDS/LGSS	3"	8	0	0	1	0	9	583.46	5,251.14	LG23"
LG2	SDS/LGSS	4"	10	0	0	4	1	15	3,882.87	58,243.05	LG24"
LG2	SDS/LGSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	LG26"
LG2	SDS/LGSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	LG28"
LG2	SDS/LGSS	UNDER 3"	46	0	1	7	0	54	1,216.88	65,711.52	LG2UNDER 3"
LG3	LDS/LGSS	4"	1	0	0	0	0	1	3,882.87	3,882.87	LG34"
NSI	MDS/NSS	3"	1	0	0	0	0	1	583.46	583.46	NSI3"

RC2	RSS/RTS	UNDER 3"	1	0	0	1	0	2	1,216.88	2,433.76	RC2UNDER 3"
RCC	RSS/RTS	UNDER 3"	17,471	133	90	2,555	2,703	22,952	1,216.88	27,929,829.76	RCCUNDER 3"
RCC	RSS/RTS	3"	0	1	0	0	0	1	583.46	583.46	RCC3"
RCC	RSS/RTS	4"	3	0	0	0	1	4	3,882.87	15,531.48	RCC4"
RCC	RSS/RTS	6"	1	0	0	0	0	1	4,996.93	4,996.93	RCC6"
RCC	RSS/RTS	10"	1	0	0	0	0	1	111.64	111.64	RCC10"
RS	RSS/RTS	10"	3	0	0	0	2	5	111.64	558.20	RS10"
RS	RSS/RTS	11-1/8"	1	0	0	0	0	1	0.00	0.00	RS11-1/8"
RS	RSS/RTS	3"	13	0	0	4	58	75	583.46	43,759.50	RS3"
RS	RSS/RTS	4"	11	1	1	4	66	83	3,882.87	322,278.21	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	2	3	11	4,996.93	54,966.23	RS6"
RS	RSS/RTS	8"	9	0	0	0	0	9	7,771.80	69,946.20	RS8"
RS	RSS/RTS	UNDER 3"	263,223	1,547	1,349	21,671	31,273	319,063	1,216.88	388,261,383.44	RSUNDER 3"
RTC	RSS/RTS	3"	1	0	0	0	8	9	583.46	5,251.14	RTC3"
RTC	RSS/RTS	4"	2	0	0	0	4	6	3,882.87	23,297.22	RTC4"
RTC	RSS/RTS	UNDER 3"	51,151	268	221	2,829	3,006	57,475	1,216.88	69,940,178.00	RTCUNDER 3"
SC2	SGSS2/SCD2/SGDS2	3"	25	0	0	5	2	32	583.46	18,670.72	SC23"
SC2	SGSS2/SCD2/SGDS2	4"	30	0	0	1	2	33	3,882.87	128,134.71	SC24"
SC2	SGSS2/SCD2/SGDS2	6"	1	0	0	2	0	3	4,996.93	14,990.79	SC26"
SC2	SGSS2/SCD2/SGDS2	UNDER 3"	881	7	5	133	86	1,112	1,216.88	1,353,170.56	SC2UNDER 3"
SCC	SGSS1/SCD1/SGDS1	3"	13	1	0	8	18	40	583.46	23,338.40	SCC3"
SCC	SGSS1/SCD1/SGDS1	4"	11	0	0	4	3	18	3,882.87	69,891.66	SCC4"
SCC	SGSS1/SCD1/SGDS1	5"	1	0	0	0	0	1	1,020.80	1,020.80	SCC5"
SCC	SGSS1/SCD1/SGDS1	UNDER 3"	4,756	54	40	1,488	1,653	7,991	1,216.88	9,724,088.08	SCCUNDER 3"
SG2	SGSS2/SCD2/SGDS2	12"	1	0	0	0	0	1	69,826.82	69,826.82	SG212"
SG2	SGSS2/SCD2/SGDS2	3"	46	0	0	8	6	60	583.46	35,007.60	SG23"
SG2	SGSS2/SCD2/SGDS2	4"	56	0	0	10	7	73	3,882.87	283,449.51	SG24"
SG2	SGSS2/SCD2/SGDS2	5"	0	0	0	0	1	1	1,020.80	1,020.80	SG25"
SG2	SGSS2/SCD2/SGDS2	6"	5	0	0	3	1	9	4,996.93	44,972.37	SG26"
SG2	SGSS2/SCD2/SGDS2	8"	1	0	0	0	0	1	7,771.80	7,771.80	SG28"
SG2	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG210"
SG2	SGSS2/SCD2/SGDS2	UNDER 3"	2,124	12	8	311	252	2,707	1,216.88	3,294,094.16	SG2UNDER 3"
SG3	SGSS1/SCD1/SGDS1	3"	1	0	0	0	0	1	583.46	583.46	SG33"
SG3	SGSS1/SCD1/SGDS1	4"	1	0	0	3	0	4	3,882.87	15,531.48	SG34"
SG3	SGSS1/SCD1/SGDS1	6"	1	0	0	1	0	2	4,996.93	9,993.86	SG36"
SG3	SGSS1/SCD1/SGDS1	10"	1	0	0	0	0	1	111.64	111.64	SG310"
SG3	SGSS1/SCD1/SGDS1	UNDER 3"	15	1	0	0	0	16	1,216.88	19,470.08	SG3UNDER 3"
SG4	SGSS2/SCD2/SGDS2	3"	3	0	0	1	0	4	583.46	2,333.84	SG43"
SG4	SGSS2/SCD2/SGDS2	4"	3	0	0	1	0	4	3,882.87	15,531.48	SG44"
SG4	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	4,996.93	4,996.93	SG46"
SG4	SGSS2/SCD2/SGDS2	UNDER 3"	23	0	0	5	1	29	1,216.88	35,289.52	SG4UNDER 3"
SGS	SGSS1/SCD1/SGDS1	10"	1	0	0	0	0	1	111.64	111.64	SGS10"
SGS	SGSS1/SCD1/SGDS1	12"	1	0	0	0	0	1	69,826.82	69,826.82	SGS12"
SGS	SGSS1/SCD1/SGDS1	16"	0	0	0	1	0	1	0.00	0.00	SGS16"
SGS	SGSS1/SCD1/SGDS1	3"	20	0	0	20	61	101	583.46	58,929.46	SGS3"

SGS	SGSS1/SCD1/SGDS1	4"	39	0	0	13	45	97	3,882.87	376,638.39	SGS4"
SGS	SGSS1/SCD1/SGDS1	5"	0	0	0	1	0	1	1,020.80	1,020.80	SGS5"
SGS	SGSS1/SCD1/SGDS1	6"	3	0	0	0	2	5	4,996.93	24,984.65	SGS6"
SGS	SGSS1/SCD1/SGDS1	8"	1	0	0	0	0	1	7,771.80	7,771.80	SGS8"
SGS	SGSS1/SCD1/SGDS1	UNDER 3"	11,966	107	84	4,339	5,616	22,112	1,216.88	26,907,650.56	SGSUNDER 3"
SGT	INACTIVE	3"	2	0	0	0	0	2	583.46	1,166.92	SGT3"
SGT	INACTIVE	4"	1	0	0	1	0	2	3,882.87	7,765.74	SGT4"
SGT	INACTIVE	UNDER 3"	14	0	0	3	1	18	1,216.88	21,903.84	SGTUNDER 3"
TAG1	SGSS1/SCD1/SGDS1	3"	4	0	0	0	1	5	583.46	2,917.30	TAG13"
TAG1	SGSS1/SCD1/SGDS1	UNDER 3"	123	0	0	36	22	181	1,216.88	220,255.28	TAG1UNDER 3"
TAG2	SGSS2/SCD2/SGDS2	3"	15	0	0	1	0	16	583.46	9,335.36	TAG23"
TAG2	SGSS2/SCD2/SGDS2	4"	23	0	0	3	1	27	3,882.87	104,837.49	TAG24"
TAG2	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	4,996.93	4,996.93	TAG26"
TAG2	SGSS2/SCD2/SGDS2	UNDER 3"	283	0	0	24	16	323	1,216.88	393,052.24	TAG2UNDER 3"
TAG5	SGSS1/SCD1/SGDS1	3"	6	0	0	1	4	11	583.46	6,418.06	TAG53"
TAG5	SGSS1/SCD1/SGDS1	4"	7	0	0	2	2	11	3,882.87	42,711.57	TAG54"
TAG5	SGSS1/SCD1/SGDS1	UNDER 3"	534	2	0	73	125	734	1,216.88	893,189.92	TAG5UNDER 3"
TAG6	SGSS2/SCD2/SGDS2	3"	53	0	0	4	1	58	583.46	33,840.68	TAG63"
TAG6	SGSS2/SCD2/SGDS2	4"	53	1	0	7	7	68	3,882.87	264,035.16	TAG64"
TAG6	SGSS2/SCD2/SGDS2	6"	5	0	0	1	0	6	4,996.93	29,981.58	TAG66"
TAG6	SGSS2/SCD2/SGDS2	UNDER 3"	979	8	3	97	53	1,140	1,216.88	1,387,243.20	TAG6UNDER 3"
TI4	SDS/LGSS	12"	1	0	0	0	0	1	69,826.82	69,826.82	TI412"
TI4	SDS/LGSS	3"	19	0	0	2	1	22	583.46	12,836.12	TI43"
TI4	SDS/LGSS	4"	25	0	0	2	0	27	3,882.87	104,837.49	TI44"
TI4	SDS/LGSS	6"	5	0	0	2	1	8	4,996.93	39,975.44	TI46"
TI4	SDS/LGSS	UNDER 3"	133	1	0	15	6	155	1,216.88	188,616.40	TI4UNDER 3"
TI8	LDS/LGSS	3"	4	0	0	0	0	4	583.46	2,333.84	TI83"
TI8	LDS/LGSS	4"	16	0	0	3	0	19	3,882.87	73,774.53	TI84"
TI8	LDS/LGSS	6"	3	0	0	1	0	4	4,996.93	19,987.72	TI86"
TI8	LDS/LGSS	8"	0	1	1	0	0	2	7,771.80	15,543.60	TI88"
TI8	LDS/LGSS	UNDER 3"	21	0	0	3	2	26	1,216.88	31,638.88	TI8UNDER 3"
TIB	SDS/LGSS	3"	25	0	0	1	0	26	583.46	15,169.96	TIB3"
TIB	SDS/LGSS	4"	54	0	0	9	1	64	3,882.87	248,503.68	TIB4"
TIB	SDS/LGSS	6"	5	0	0	0	1	6	4,996.93	29,981.58	TIB6"
TIB	SDS/LGSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	TIB8"
TIB	SDS/LGSS	UNDER 3"	132	1	0	15	5	153	1,216.88	186,182.64	TIBUNDER 3"
TIF	LDS/LGSS	3"	8	0	0	1	0	9	583.46	5,251.14	TIF3"
TIF	LDS/LGSS	4"	12	0	0	1	1	14	3,882.87	54,360.18	TIF4"
TIF	LDS/LGSS	6"	3	0	0	0	0	3	4,996.93	14,990.79	TIF6"
TIF	LDS/LGSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	TIF8"
TIF	LDS/LGSS	UNDER 3"	50	1	1	4	1	57	1,216.88	69,362.16	TIFUNDER 3"
TIG	LDS/LGSS	3"	2	0	0	0	0	2	583.46	1,166.92	TIG3"
TIG	LDS/LGSS	4"	1	0	0	0	0	1	3,882.87	3,882.87	TIG4"
TIG	LDS/LGSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TIG6"
TIG	LDS/LGSS	8"	0	0	0	1	0	1	7,771.80	7,771.80	TIG8"
TIG	LDS/LGSS	UNDER 3"	2	0	0	1	0	3	1,216.88	3,650.64	TIGUNDER 3"

TIH	LDS/LGSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TIH6"
TM1	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	TM1UNDER 3"
TM1	MDS/NSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TM16"
TM3	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	TM3UNDER 3"
TMB	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	TMBUNDER 3"
TMB	MDS/NSS	4"	1	0	0	0	0	1	3,882.87	3,882.87	TMB4"
TMB	MDS/NSS	6"	0	0	0	1	0	1	4,996.93	4,996.93	TMB6"
TMB	MDS/NSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	TMB8"
TMC	MDS/NSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TMC6"
UNKNOWN			2,301	9	11	432	781	3,534	UNKNOWN	UNKNOWN	UNKNOWN
			356,992	2,156	1,815	34,194	45,922	441,079		534,436,105.05	
Check Total			0	0	0	0	0	0			

		Total Cost	Percent
	RSS/RTS	**486,677,146.77**	**91.077%**
	SGSS1/SCD1/SGDS1	**38,476,455.71**	**7.200%**
	SGSS2/SCD2/SGDS2	**7,536,695.89**	**1.410%**
	SDS/LGSS	**1,122,960.30**	**0.210%**
	LDS/LGSS	**325,363.60**	**0.061%**
	FLEX	**224,003.17**	**0.042%**
	TOTAL BEFORE MDS/NSS	**534,362,625.44**	**100.000%**
	MDS/NSS	**25,882.63**	
	FLEX MDS	**16,760.48**	
	TOTAL	**534,405,268.55**	
	UNKNOWN	**96,948,763.85**	
101-1000	**TOTAL ACCOUNT 380**	**631,354,032.40**	
101-2000	**CIAC**	**(1,108,063.83)**	
101-4000	**Relocation Reimbursements**	**(17,664.36)**	
106	**Completed Construction not Classifie**	**226,649.97**	
Total	**Per Exhibit 8, Schedule 1**	**630,454,954.18**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 16
METERS

LINE NO.	RATE CODE	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX	MLDS	TOTAL
		$	$	$	$	$		$	$
1	802	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
2	803	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	806	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	808	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
5	809	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
6	810	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
7	816	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
8	819	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	820	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	830	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	831	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
12	833	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
13	838	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	840	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
15	845	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	846	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
17	847	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
18	848	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
19	856	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	857	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
21	868	0.00	0.00	0.00	0.00	0.00	859.63	0.00	859.63
22	872	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	873	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
24	875	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
25	876	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
26	877	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
27	879	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
28	880	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
29	881	0.00	0.00	0.00	0.00	0.00	981.93	0.00	981.93
30	LG1	0.00	0.00	0.00	24,455.23	0.00	0.00	0.00	24,455.23
31	LG2	0.00	0.00	0.00	42,298.44	0.00	0.00	0.00	42,298.44
32	LG3	0.00	0.00	0.00	0.00	1,289.43	0.00	0.00	1,289.43
33	LG4	0.00	0.00	0.00	0.00	1,289.43	0.00	0.00	1,289.43
34	LG5	0.00	0.00	0.00	0.00	429.81	0.00	0.00	429.81
35	NSI	0.00	0.00	0.00	0.00	0.00	0.00	56.54	56.54
36	RCC	1,378,601.56	0.00	0.00	0.00	0.00	0.00	0.00	1,378,601.56
37	RC2	17,473.25	0.00	0.00	0.00	0.00	0.00	0.00	17,473.25
38	RS	19,724,428.18	0.00	0.00	0.00	0.00	0.00	0.00	19,724,428.18
39	RTC	3,549,108.68	0.00	0.00	0.00	0.00	0.00	0.00	3,549,108.68
40	SCC	0.00	1,159,605.07	0.00	0.00	0.00	0.00	0.00	1,159,605.07
41	SC2	0.00	0.00	537,923.32	0.00	0.00	0.00	0.00	537,923.32
42	SG2	0.00	0.00	1,282,896.24	0.00	0.00	0.00	0.00	1,282,896.24
43	SG3	0.00	10,403.65	0.00	0.00	0.00	0.00	0.00	10,403.65
44	SG4	0.00	0.00	17,571.68	0.00	0.00	0.00	0.00	17,571.68
45	SGS	0.00	3,176,551.15	0.00	0.00	0.00	0.00	0.00	3,176,551.15
46	TAG1	0.00	42,034.90	0.00	0.00	0.00	0.00	0.00	42,034.90
47	TAG2	0.00	0.00	160,610.52	0.00	0.00	0.00	0.00	160,610.52
48	TAG5	0.00	206,474.49	0.00	0.00	0.00	0.00	0.00	206,474.49
49	TAG6	0.00	0.00	547,406.87	0.00	0.00	0.00	0.00	547,406.87
50	TI4	0.00	0.00	0.00	66,216.81	0.00	0.00	0.00	66,216.81
51	TI8	0.00	0.00	0.00	0.00	21,446.58	0.00	0.00	21,446.58
52	TIB	0.00	0.00	0.00	116,253.39	0.00	0.00	0.00	116,253.39
53	TIF	0.00	0.00	0.00	0.00	30,691.60	0.00	0.00	30,691.60
54	TIG	0.00	0.00	0.00	0.00	3,008.68	0.00	0.00	3,008.68
55	TIH	0.00	0.00	0.00	0.00	429.81	0.00	0.00	429.81
56	TMB	0.00	0.00	0.00	0.00	0.00	0.00	1,289.44	1,289.44
57	TMC	0.00	0.00	0.00	0.00	0.00	0.00	429.81	429.81
58	TM1	0.00	0.00	0.00	0.00	0.00	0.00	263.45	263.45
59	TM2	0.00	0.00	0.00	0.00	0.00	0.00	263.45	263.45
60	TOTAL	24,669,611.67	4,595,069.26	2,546,408.63	249,223.87	58,585.34	12,157.00	2,302.69	32,133,358.46
61	**OR #16**	76.772%	14.300%	7.925%	0.776%	0.182%	0.038%	0.007%	100.000%

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2020

Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
37	10034190010	501054825	SGT	TAG6	49103	30209	7,900.78	TAG6	SGSS2/SCD2/SGDS2
37	10047952001	400188814	SGT	TI4	45529	30243	11,446.47	TI4	SDS/LGSS
37	10219299006	501195093	LG1		49394	732195	41,114.02	LG1	SDS/LGSS
37	10257973005	500030237	SG4		48810	1232756	9,184.43	SG4	SGSS2/SCD2/SGDS2
37	10348091005	400518175	SG4		44452	1333017	3,025.61	SG4	SGSS2/SCD2/SGDS2
37	10375621158	500489101	SGT	TIB	47567	1333032	11,290.77	TIB	SDS/LGSS
37	10379912006	400498094	SC2		14628	1333032	4,546.21	SC2	SGSS2/SCD2/SGDS2
37	10405620001	400044475	SGT	TAG6	45746	1333095	14,904.77	TAG6	SGSS2/SCD2/SGDS2
37	10416756005	500065176	SC2		47085	1333063	708.65	SC2	SGSS2/SCD2/SGDS2
37	10421482002	500617033	SGT	TIB	49153	551504	44,715.05	TIB	SDS/LGSS
37	10422436002	400343911	SGT	TIB	46123	10155	8,766.90	TIB	SDS/LGSS
37	10468703002	400525452	SGT	TI4	48454	1292914	11,690.05	TI4	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	12983111001	400473518	SGT		661	1232704	20,610.83	SGT	INACTIVE
37	12983117003	400473502	LG2		49426	1232718	2,233.40	LG2	SDS/LGSS
37	12983124002	400473470	SG3		593	832295	916.28	SG3	SGSS1/SCD1/SGDS1
37	12983149001	800800461	SGT	TAG6	14545	1292906	5,738.98	TAG6	SGSS2/SCD2/SGDS2
37	12983153001	800800460	SGT	TAG6	1414	1292906	5,172.69	TAG6	SGSS2/SCD2/SGDS2
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	SGT	TI4	14324	1292906	855.29	TI4	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	SGT	TAG6	1434	511318	5,116.21	TAG6	SGSS2/SCD2/SGDS2
37	12983205001	400473388	SC2		4299	511314	5,425.75	SC2	SGSS2/SCD2/SGDS2
37	12983206002	500135694	SGT	TI4	1405	511314	2,584.87	TI4	SDS/LGSS
37	12983208001	400473368	SG2		4584	511314	2,944.67	SG2	SGSS2/SCD2/SGDS2
37	12983210001	400473364	SGT	TI4	4614	511314	2,618.96	TI4	SDS/LGSS
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	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	11,015.12	TIB	SDS/LGSS
37	12983259002	400473238	SGT	TIB	1280	511396	247.56	TIB	SDS/LGSS
37	12983259002	500135609	SGT	TIB	1280	511396	247.56	TIB	SDS/LGSS
37	12983262001	400513746	SGT	TI8	44092	511363	(1,937.70)	TI8	LDS/LGSS
37	12983275001	400473402	SGT	TI4	1423	1112553	2,575.48	TI4	SDS/LGSS
37	12983276001	400473401	SGT	TIB	3382	1112553	13,360.04	TIB	SDS/LGSS
37	12983281001	400473412	SG2		1432	1112521	3,135.76	SG2	SGSS2/SCD2/SGDS2
37	12983282001	400473411	SGT	TIB	1431	1112569	2,375.82	TIB	SDS/LGSS
37	12983287001	400473405	SGT	TIB	1426	1112521	6,824.22	TIB	SDS/LGSS
37	12983292002	400473346	LG1		1372	1112561	8,327.98	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	TAG6	1305	1112569	1,771.37	TAG6	SGSS2/SCD2/SGDS2
37	12983301001	400473229	SGT	TI4	4252	1112553	1,853.55	TI4	SDS/LGSS
37	12983302001	400502918	SC2		4492	1112521	1,179.62	SC2	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	7,100.40	TAG6	SGSS2/SCD2/SGDS2

37	12983343001	400512909	SGT	EDSTIB1	3295	1252863	2,316.71	EDSTIB1	SDS/LGSS
37	12983344001	400497701	SGT	TAG6	1469	1292986	1,721.17	TAG6	SGSS2/SCD2/SGDS2
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	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	663.83	TIB	SDS/LGSS
37	12983355011	500287938	SGT	TIB	47386	1252855	663.83	TIB	SDS/LGSS
37	12983359001	400473342	SGT	TIB	1364	1252858	1,868.32	TIB	SDS/LGSS
37	12983370001	400495171	SG2		3323	1252863	4,538.11	SG2	SGSS2/SCD2/SGDS2
37	12983403001	400472841	SGT	TI8	718	732195	8,285.78	TI8	LDS/LGSS
37	12983415001	400473189	SGT	TI8	1005	732158	9,302.44	TI8	LDS/LGSS
37	12983428003	400502425	SGT	816	14126	732153	(2,300.48)	816	FLEX
37	12983429002	400472946	SGT	TIB	807	70409	8,319.92	TIB	SDS/LGSS
37	12983433001	400512973	SGT	810	44075	732195	4,278.82	810	FLEX
37	12983434002	400472904	SGT	808	776	732153	93,547.00	808	FLEX
37	12983443007	400488177	LG2		14348	732153	9,005.38	LG2	SDS/LGSS
37	12983451001	400473180	SGT	TI4	997	732114	9,679.14	TI4	SDS/LGSS
37	12983453001	400473149	SGT	TAG6	974	732111	3,769.98	TAG6	SGSS2/SCD2/SGDS2
37	12983462001	400473064	SGT	TAG6	893	732195	1,831.53	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	12983474002	400472983	SGT	TI8	832	732195	14,328.04	TI8	LDS/LGSS
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	12983498005	800800442	SGT	TIB	4410	70458	1,250.67	TIB	SDS/LGSS
37	12983504001	400473099	SGT	TIB	924	70451	10,408.46	TIB	SDS/LGSS
37	12983508002	400508899	SGT	TI8	871	70424	9,181.24	TI8	LDS/LGSS
37	12983513001	400472886	SGT	TIB	760	70471	2,467.02	TIB	SDS/LGSS
37	12983515001	400472854	SGT	TI4	733	70471	2,053.49	TI4	SDS/LGSS
37	12983517002	400505175	SGT	TIG	14699	70468	23,377.51	TIG	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	12983545001	400473135	SGT	TAG6	960	70454	975.58	TAG6	SGSS2/SCD2/SGDS2
37	12983554002	400510507	SGT	TI4	926	70495	732.91	TI4	SDS/LGSS
37	12983554002	500146350	SGT	TI4	926	70495	732.91	TI4	SDS/LGSS
37	12983556001	400475899	SGT	TIB	906	70456	8,689.61	TIB	SDS/LGSS
37	12983557001	400473076	SGT	TI4	908	70404	982.95	TI4	SDS/LGSS
37	12983577003	400472935	SGT	TIB	801	70495	52,247.68	TIB	SDS/LGSS
37	12983589001	400472900	SGT	TAG6	772	70478	886.49	TAG6	SGSS2/SCD2/SGDS2
37	12983603001	400472840	SGT	TI4	4550	70405	2,829.72	TI4	SDS/LGSS
37	12983606002	400472820	SGT	TAG6	702	70495	23,896.62	TAG6	SGSS2/SCD2/SGDS2
37	12983611001	400503381	SGT	TI8	14705	70403	3,827.45	TI8	LDS/LGSS
37	12983623002	400473179	SGT	TAG6	996	310911	3,442.72	TAG6	SGSS2/SCD2/SGDS2
37	12983626001	400473108	SGT	TAG6	933	310958	622.61	TAG6	SGSS2/SCD2/SGDS2
37	12983627001	400473107	SGT	TAG6	932	310956	498.89	TAG6	SGSS2/SCD2/SGDS2
37	12983630001	400526948	SG2		4420	333908	15,255.74	SG2	SGSS2/SCD2/SGDS2
37	12983644001	400512422	SGT	TIB	1155	1252896	10,801.61	TIB	SDS/LGSS
37	12983645004	400492992	SGT	802	1121	1252804	12,553.25	802	FLEX MDS
37	12983645004	500142415	SGT	802	1121	1252804	12,553.25	802	FLEX MDS
37	12983646002	400481256	SGT	TI8	1114	1252804	14,725.43	TI8	LDS/LGSS
37	12983651001	400472750	SGT	TIF	1241	1252829	5,178.66	TIF	LDS/LGSS
37	12983654002	400472745	SGT	TAG2	1236	1252896	6,610.88	TAG2	SGSS2/SCD2/SGDS2
37	12983663001	400505567	SGT	TAG2	14764	1252821	3,352.37	TAG2	SGSS2/SCD2/SGDS2
37	12983681002	400472637	SGT	TI4	1141	1252803	18,010.19	TI4	SDS/LGSS
37	12983693004	400506899	SGT	TI4	14766	1252821	4,992.09	TI4	SDS/LGSS
37	12983778004	400526322	SGT	TI4	44903	30287	27,762.30	TI4	SDS/LGSS
37	12983801005	500151204	SGT	846	1225	30205	13,256.29	846	FLEX
37	12983801005	800800501	SGT	846	1227	30257	477.96	846	FLEX
37	12983811001	400472633	SGT	TIB	1138	30298	35,737.31	TIB	SDS/LGSS

37	12983816001	400497901	SGT	847	14538	30298	6,397.42	847	FLEX
37	12983822001	400472761	SGT	TAG6	1252	30244	1,277.77	TAG6	SGSS2/SCD2/SGDS2
37	12983855001	400472621	SG2		3401	30224	1,484.68	SG2	SGSS2/SCD2/SGDS2
37	12983862002	400472577	SGT	TAG2	4353	30298	10,749.20	TAG2	SGSS2/SCD2/SGDS2
37	12983868001	800800388	LG1		1073	30236	1,054.99	LG1	SDS/LGSS
37	12983871001	400472535	SGT	TAG6	1049	30298	12,117.18	TAG6	SGSS2/SCD2/SGDS2
37	12983873001	400472530	SGT	TAG6	4287	30287	1,952.86	TAG6	SGSS2/SCD2/SGDS2
37	12983875003	501090417	SGT	TIB	49141	30287	77,635.13	TIB	SDS/LGSS
37	12983885004	400472514	SGT	TIB	48589	30295	0.00	TIB	SDS/LGSS
37	12983886001	400472513	SGT	TAG2	4687	30295	2,325.82	TAG2	SGSS2/SCD2/SGDS2
37	12983915002	400472655	SGT	TIB	1159	30216	15,518.72	TIB	SDS/LGSS
37	12983934001	400484301	SGT	TIF	937	70452	4,620.19	TIF	LDS/LGSS
37	12983936001	400473091	SGT	TI8	916	30225	17,199.27	TI8	LDS/LGSS
37	12983938001	400473088	SGT	TIF	913	30225	25,841.42	TIF	LDS/LGSS
37	12983938002	400473011	SGT	TI8	49348	30225	25,397.78	TI8	LDS/LGSS
37	12983939001	400473057	SGT	TIF	887	30225	260,120.07	TIF	LDS/LGSS
37	12983946001	400493917	SGT	TMC	14046	70452	129,641.36	TMC	MDS/NSS
37	12983954001	400518548	SGT	TAG2	1016	30280	1,793.76	TAG2	SGSS2/SCD2/SGDS2
37	12983968001	400473146	SGT	TI4	971	30280	1,505.38	TI4	SDS/LGSS
37	12983969001	400473144	SGT	TI8	4078	30280	6,739.92	TI8	LDS/LGSS
37	12983971001	400473142	SGT	TIB	968	30263	3,123.75	TIB	SDS/LGSS
37	12983976001	400473125	SC2		949	30231	2,662.32	SC2	SGSS2/SCD2/SGDS2
37	12983982001	400473103	SGT	TI4	929	30272	356.76	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	12984012005	400526772	SGT	TAG6	810	30272	2,131.13	TAG6	SGSS2/SCD2/SGDS2
37	12984057001	400472794	SGT	TAG2	14003	70452	2,817.69	TAG2	SGSS2/SCD2/SGDS2
37	12984060001	400472789	SGT	TI4	675	30231	2,006.04	TI4	SDS/LGSS
37	12984091001	400472776	SGT	TIB	3296	1252806	2,490.72	TIB	SDS/LGSS
37	12984098001	400526718	SGT	TM1	45180	1252822	3,030.87	TM1	MDS/NSS
37	12984098003	400490002	SGT	TI8	14453	10154	2,599.58	TI8	LDS/LGSS
37	12984119001	400494178	SG2		1174	1252823	27,949.22	SG2	SGSS2/SCD2/SGDS2
37	12984122008	400472639	SGT	TIB	48825	1252822	13,064.41	TIB	SDS/LGSS
37	12984125001	400472585	SGT	TIB	4502	1252819	3,398.13	TIB	SDS/LGSS
37	12984129002	400472553	SGT	TIB	1070	1252807	4,903.64	TIB	SDS/LGSS
37	12984131002	500789128	SGT	TIB	48657	1252822	6,756.22	TIB	SDS/LGSS
37	12984147008	400520146	SGT	TAG6	47452	1252807	398.38	TAG6	SGSS2/SCD2/SGDS2
37	12984148002	500185413	SGT		49412	30241	45,917.22	SGT	INACTIVE
37	12984148003	400518885	SGT	TIB	44408	30241	7,603.27	TIB	SDS/LGSS
37	12984150004	501030792	SGT	875	49154	273860	490.06	875	FLEX
37	12984150004	800800371	SGT	875	4385	273804	8,104.06	875	FLEX
37	12984150007	501179703	SG2		49333	273860	490.06	SG2	SGSS2/SCD2/SGDS2
37	12984151020	400475666	SGT	TIF	1565	273860	287.79	TIF	LDS/LGSS
37	12984151020	400514859	SGT	TIF	48789	273860	490.06	TIF	LDS/LGSS
37	12984151020	400514976	SGT	TIF	48788	273860	490.06	TIF	LDS/LGSS
37	12984151020	400526997	SGT	TIF	45666	273860	490.06	TIF	LDS/LGSS
37	12984151020	500008214	SGT	TIF	48790	273860	490.06	TIF	LDS/LGSS
37	12984151020	500130476	SGT	TIF	45665	273860	490.06	TIF	LDS/LGSS
37	12984151020	500130460	SGT	TIF	45732	273804	233.25	TIF	LDS/LGSS
37	12984151020	500130474	SGT	TIF	48526	273860	490.06	TIF	LDS/LGSS
37	12984151020	500130459	SGT	TIF	48889	273860	490.06	TIF	LDS/LGSS
37	12984151020	500136322	SGT	TIF	45731	273804	233.25	TIF	LDS/LGSS
37	12984151020	500150517	SGT	TIF	45908	273860	490.06	TIF	LDS/LGSS
37	12984151020	500162068	SGT	TIF	45949	273860	490.06	TIF	LDS/LGSS
37	12984151020	500198356	SGT	TIF	46017	273804	233.25	TIF	LDS/LGSS
37	12984151020	500198359	SGT	TIF	46018	273804	5,166.36	TIF	LDS/LGSS
37	12984151020	500208315	SGT	TIF	46494	273804	233.25	TIF	LDS/LGSS
37	12984151020	500555580	SGT	TIF	48444	273860	490.06	TIF	LDS/LGSS
37	12984151020	500558423	SGT	TIF	48887	273860	490.06	TIF	LDS/LGSS

37	12984151020	500612327	SGT	TIF	48438	273804	233.25	TIF	LDS/LGSS
37	12984151020	500625771	SGT	TIF	48958	273860	586.51	TIF	LDS/LGSS
37	12984151020	500659013	SGT	TIF	48965	273860	490.06	TIF	LDS/LGSS
37	12984151020	500667297	SGT	TIF	48439	273804	233.25	TIF	LDS/LGSS
37	12984151020	500667298	SGT	TIF	48440	273860	(10,506.34)	TIF	LDS/LGSS
37	12984151020	500692603	SGT	TIF	48625	273860	490.06	TIF	LDS/LGSS
37	12984151020	500707423	SGT	TIF	48970	273804	233.25	TIF	LDS/LGSS
37	12984151020	500709556	SGT	TIF	48543	273860	490.06	TIF	LDS/LGSS
37	12984151020	500716291	SGT	TIF	48471	273860	490.06	TIF	LDS/LGSS
37	12984151020	500806647	SGT	TIF	48678	273860	490.06	TIF	LDS/LGSS
37	12984151020	500856054	SGT	TIF	48736	273804	233.25	TIF	LDS/LGSS
37	12984151020	500875536	SGT	TIF	48749	273804	233.25	TIF	LDS/LGSS
37	12984151020	500918034	SGT	TIF	48624	273860	490.06	TIF	LDS/LGSS
37	12984151020	500949336	SGT	TIF	48808	273860	490.06	TIF	LDS/LGSS
37	12984151020	500949337	SGT	TIF	48809	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800356	SGT	TIF	4371	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800357	SGT	TIF	4373	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800358	SGT	TIF	4374	273860	1,555.96	TIF	LDS/LGSS
37	12984151020	800800359	SGT	TIF	4375	273860	1,235.30	TIF	LDS/LGSS
37	12984151020	800800360	SGT	TIF	4376	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800361	SGT	TIF	4377	273860	825.56	TIF	LDS/LGSS
37	12984151020	800800362	SGT	TIF	4378	273860	2,892.02	TIF	LDS/LGSS
37	12984151020	800800364	SGT	TIF	4380	273860	550.88	TIF	LDS/LGSS
37	12984151020	800800365	SGT	TIF	4381	273804	233.25	TIF	LDS/LGSS
37	12984151020	800800366	SGT	TIF	4382	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800367	SGT	TIF	4383	273860	2,705.00	TIF	LDS/LGSS
37	12984151020	800800369	SGT	TIF	14823	273860	(237.74)	TIF	LDS/LGSS
37	12984151020	800800370	SGT	TIF	45243	273804	233.25	TIF	LDS/LGSS
37	12984151020	800800354	SGT	TIF	49234	273860	490.06	TIF	LDS/LGSS
37	12984151070	500599616	SGT		48888	273860	490.06	SGT	INACTIVE
37	12984151071	500972343	SGT		48807	273804	233.25	SGT	INACTIVE
37	12984151071	501078814	SGT		49357	273860	490.06	SGT	INACTIVE
37	12984151071	501102376	SGT		49356	273860	490.06	SGT	INACTIVE
37	12984156001	400498964	SGT	TI8	14387	273821	5,213.78	TI8	LDS/LGSS
37	12984156007	501140885	SGT	881	49402	1212650	0.00	881	FLEX
37	12984156007	501140884	SGT	881	49404	1212650	0.00	881	FLEX
37	12984182002	400472462	SGT	TIB	4457	273860	10,145.74	TIB	SDS/LGSS
37	12984188002	400472449	SGT	TIF	4450	273804	353,710.72	TIF	LDS/LGSS
37	12984215001	400526343	SGT	TI4	44949	273804	233.25	TI4	SDS/LGSS
37	12984218002	400472435	SGT	TIB	1493	551552	0.00	TIB	SDS/LGSS
37	12984219005	400472431	LG2		294	551501	1,230.00	LG2	SDS/LGSS
37	12984219005	500165435	LG2		294	551501	1,230.00	LG2	SDS/LGSS
37	12984221002	400472381	SGT	TIB	1490	551501	5,370.70	TIB	SDS/LGSS
37	12984221004	501123144	SGT	TI8	49284	551501	1,956.54	TI8	LDS/LGSS
37	12984230001	400472414	SGT	TI4	1513	551554	4,102.66	TI4	SDS/LGSS
37	12984232001	400472408	NSI		1511	551511	1,085.90	NSI	MDS/NSS
37	12984233004	400472404	SGT	TI8	1508	551553	0.00	TI8	LDS/LGSS
37	12984233004	800800336	SGT	TI8	4507	551553	9,209.77	TI8	LDS/LGSS
37	12984235003	400503659	SGT	TI4	14732	551511	8,739.95	TI4	SDS/LGSS
37	12984235003	500232234	SGT	TI4	48041	551511	1,085.90	TI4	SDS/LGSS
37	12984245001	400514975	SGT	TAG6	44087	10153	2,947.61	TAG6	SGSS2/SCD2/SGDS2
37	12984246003	500416284	SGT	TAG6	47469	1333025	22,467.14	TAG6	SGSS2/SCD2/SGDS2
37	12984247004	400472434	SGT	TIF	297	10109	12,937.44	TIF	LDS/LGSS
37	12984247004	400472433	SGT	TIF	4339	10109	4,963.02	TIF	LDS/LGSS
37	12984247004	800800335	SGT	TIF	14446	10109	6,918.53	TIF	LDS/LGSS
37	12984250003	400507411	SGT	TI8	3215	10154	2,625.29	TI8	LDS/LGSS
37	12984250003	400507413	SGT	TI8	3215	10154	2,625.29	TI8	LDS/LGSS
37	12984251001	400507412	SGT	TIB	1510	10120	13,172.01	TIB	SDS/LGSS
37	12984252001	400472401	SGT	TAG6	1506	10160	2,716.17	TAG6	SGSS2/SCD2/SGDS2
37	12984255005	400472391	SGT	TAG6	4293	10158	3,969.19	TAG6	SGSS2/SCD2/SGDS2
37	12984257002	400472388	SGT	TIF	3334	10120	389.22	TIF	LDS/LGSS
37	12984257002	500149512	SGT	TIF	1496	10120	11,461.41	TIF	LDS/LGSS

37	12984261001	400472371	SGT	TIF	3384	10114	417.56	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	4,285.84	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	8,704.10	TIB	SDS/LGSS
37	12984276001	400511898	SGT	TIB	44051	10157	2,268.56	TIB	SDS/LGSS
37	12984281001	400472403	SC2		1507	10157	5,011.48	SC2	SGSS2/SCD2/SGDS2
37	12984282002	400472402	SGT	TI4	3499	10119	1,353.99	TI4	SDS/LGSS
37	12984283001	400472399	SGT	TI4	3187	10158	2,708.97	TI4	SDS/LGSS
37	12984291001	400472378	SGT	TAG6	1486	10157	3,434.35	TAG6	SGSS2/SCD2/SGDS2
37	12984293002	400472376	SGT	TMB	285	10109	13,185.56	TMB	MDS/NSS
37	12984293003	500925519	SGT		48785	10109	16,768.97	SGT	INACTIVE
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	(4,696.74)	TI8	LDS/LGSS
37	12984318001	400051028	SGT	TI8	48031	1333063	708.65	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	708.65	TI8	LDS/LGSS
37	12984318001	400505362	SGT	TI8	48677	1333063	708.65	TI8	LDS/LGSS
37	12984318001	400507194	SGT	TI8	46075	1333063	708.65	TI8	LDS/LGSS
37	12984318001	400514810	SGT	TI8	48034	1333063	708.65	TI8	LDS/LGSS
37	12984318001	500005922	SGT	TI8	48032	1333063	708.65	TI8	LDS/LGSS
37	12984318001	500119649	SGT	TI8	45688	1333063	3,470.16	TI8	LDS/LGSS
37	12984321001	400472320	SGT	TI4	3543	1333025	2,924.99	TI4	SDS/LGSS
37	12984323001	400472318	SGT	TI8	3632	1333025	32,431.00	TI8	LDS/LGSS
37	12984324001	400472317	SC2		3542	1333025	1,613.38	SC2	SGSS2/SCD2/SGDS2
37	12984325001	400472316	SGT	TIG	3631	1333025	11,349.73	TIG	LDS/LGSS
37	12984327001	400472263	SGT	TI4	4536	1333025	1,730.75	TI4	SDS/LGSS
37	12984329001	400526741	SGT	TIG	45205	1333025	29,437.80	TIG	LDS/LGSS
37	12984343004	400490919	SGT	TIG	14417	1333063	18,898.59	TIG	LDS/LGSS
37	12984343004	500023117	SGT	TIG	48880	1333063	708.65	TIG	LDS/LGSS
37	12984343004	500535850	SGT	TIG	48881	1333063	708.65	TIG	LDS/LGSS
37	12984346001	400526951	SGT	TIB	44971	1333025	3,724.43	TIB	SDS/LGSS
37	12984351001	400472299	SGT	TI4	3527	1333025	5,492.43	TI4	SDS/LGSS
37	12984355001	400472293	LG1		3521	10103	1,321.13	LG1	SDS/LGSS
37	12984357001	400472287	SGT	TIF	3625	1333063	194.35	TIF	LDS/LGSS
37	12984366001	400472272	SGT	TI8	3506	1333063	5,146.65	TI8	LDS/LGSS
37	12984368001	400472269	SGT	TIB	3504	1333063	3,476.30	TIB	SDS/LGSS
37	12984378001	400496892	SGT	TAG6	14565	1333017	2,669.44	TAG6	SGSS2/SCD2/SGDS2
37	12984382001	400493516	SGT	TIB	14532	1333017	12,842.45	TIB	SDS/LGSS
37	12984392002	400472214	SGT	TIB	3569	1333074	2,525.70	TIB	SDS/LGSS
37	12984392002	400472233	SGT	TIB	3649	1333074	8,902.25	TIB	SDS/LGSS
37	12984392002	800800313	SGT	TIB	3648	1333074	3,347.55	TIB	SDS/LGSS
37	12984428001	400493347	SGT	TI4	3950	1333032	4,743.56	TI4	SDS/LGSS
37	12984433001	400474737	SGT	TIB	14041	1333014	5,653.11	TIB	SDS/LGSS
37	12984438005	400517692	SGT	TI8	14678	1333029	4,928.91	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	5,990.82	TI8	LDS/LGSS
37	12984440001	400472099	SGT	TIB	3909	1333032	280.24	TIB	SDS/LGSS
37	12984442001	400472096	SGT	TIG	14693	1333032	6,597.70	TIG	LDS/LGSS
37	12984443001	400472090	SGT	TIB	3901	1333095	1,466.35	TIB	SDS/LGSS
37	12984447001	400526359	SGT	TI8	3894	1333032	43,301.57	TI8	LDS/LGSS
37	12984448001	400472085	SGT	TI8	3893	1333027	932.88	TI8	LDS/LGSS
37	12984450007	500793520	SGT	TIF	48680	1333027	13,001.87	TIF	LDS/LGSS
37	12984453004	400505585	SGT	TIB	3881	1333029	15,312.79	TIB	SDS/LGSS
37	12984460001	400472065	SGT	TIB	3866	1333017	1,150.36	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	12984477004	400472012	SC2		3792	1333027	600.79	SC2	SGSS2/SCD2/SGDS2
37	12984477004	800800315	SC2		3793	1333027	14.60	SC2	SGSS2/SCD2/SGDS2
37	12984484006	400467049	SGT	TIB	47453	1333083	121.30	TIB	SDS/LGSS
37	12984484006	400471998	SGT	TIB	14566	1333083	4,528.52	TIB	SDS/LGSS
37	12984484006	500151812	SGT	TIB	47456	1333083	121.30	TIB	SDS/LGSS
37	12984490001	400526586	SGT	TIF	4037	1333079	57,348.04	TIF	LDS/LGSS
37	12984493001	400471935	SGT	TAG2	4516	1333095	1,233.13	TAG2	SGSS2/SCD2/SGDS2
37	12984497001	400471892	SGT	TIB	4173	1333095	1,122.71	TIB	SDS/LGSS
37	12984501001	400471867	SGT	TIF	4155	1333095	3,725.00	TIF	LDS/LGSS
37	12984507001	400471805	SGT	TIB	4556	1333014	5,773.32	TIB	SDS/LGSS
37	12984524001	400507001	SGT	TIB	14552	1333017	4,496.64	TIB	SDS/LGSS
37	12984528001	400507730	SGT	TIF	3971	1333029	4,984.94	TIF	LDS/LGSS
37	12984529002	400495160	SGT	831	293	290806	0.00	831	FLEX MDS
37	12984533001	400494422	SGT	TI8	14521	1333027	1,675.67	TI8	LDS/LGSS
37	12984534001	400491763	SGT	TAG6	14383	1333029	323.82	TAG6	SGSS2/SCD2/SGDS2
37	12984538001	400496374	SGT	TIB	14554	1333095	2,344.33	TIB	SDS/LGSS
37	12984541001	400472240	SGT	TIB	4443	1333074	2,583.06	TIB	SDS/LGSS
37	12984542001	400499351	SC2		14534	1333029	3,158.50	SC2	SGSS2/SCD2/SGDS2
37	12984549001	400496547	SGT	TIB	14438	1333095	5,049.11	TIB	SDS/LGSS
37	12984569008	400472068	SGT	TIF	3869	1333029	16,245.21	TIF	LDS/LGSS
37	12984569008	400492606	SGT	TIF	47118	1333029	10,688.18	TIF	LDS/LGSS
37	12984569008	400505836	SGT	TIF	47356	1333029	5,990.82	TIF	LDS/LGSS
37	12984569008	400516746	SGT	TIF	47028	1333029	5,990.82	TIF	LDS/LGSS
37	12984585004	400472035	SGT	TIB	3824	1333029	12.68	TIB	SDS/LGSS
37	12984585004	800800310	SGT	TIB	3825	1333029	211.51	TIB	SDS/LGSS
37	12984592001	400471991	SGT	TI8	3698	1333069	12,248.59	TI8	LDS/LGSS
37	12984598001	400471984	SGT	TI4	3751	1333005	3,433.09	TI4	SDS/LGSS
37	12984606001	400471973	SGT	TIB	3736	1333026	7,589.21	TIB	SDS/LGSS
37	12984607002	400471965	SGT	TI4	3728	1333027	4,576.34	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	7,304.36	TAG6	SGSS2/SCD2/SGDS2
37	12984624003	400471915	SGT	TIB	3763	1333032	4,434.71	TIB	SDS/LGSS
37	12984628004	400471893	SGT	TIB	3686	1333029	4,477.49	TIB	SDS/LGSS
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	TAG6	45046	1333014	2,190.07	TAG6	SGSS2/SCD2/SGDS2
37	12984661003	400500358	SGT	TIB	14657	10101	23,195.59	TIB	SDS/LGSS
37	12984661004	500738669	SGT	TIB	48592	1333032	20,273.39	TIB	SDS/LGSS
37	13188422011	500079934	SGT	TIF	49385	273806	3,326.29	TIF	LDS/LGSS
37	13188422011	500325346	SGT	TIF	49384	273806	2,119.27	TIF	LDS/LGSS
37	13237020002	500135596	SGT	TI8	4638	511396	31,407.24	TI8	LDS/LGSS
37	13241895007	501021913	SGT	TIF	49028	30225	41,352.90	TIF	LDS/LGSS
37	13241895007	501028115	SGT	TIF	49013	30225	41,352.90	TIF	LDS/LGSS
37	13264345002	400520745	SG2		1306	1292913	3,173.68	SG2	SGSS2/SCD2/SGDS2
37	13266182003	400473258	SGT	TMB	1296	1252858	2,294.81	TMB	MDS/NSS
37	13333833001	500159224	LG1		45928	551501	6,277.25	LG1	SDS/LGSS
37	13409908003	800800444	SGT	TI4	289	70406	2,190.25	TI4	SDS/LGSS
37	13418879001	500171349	SG2		45520	30205	11,235.36	SG2	SGSS2/SCD2/SGDS2
37	13503540001	500099035	SGT	TAG6	45872	1252862	11,513.92	TAG6	SGSS2/SCD2/SGDS2
37	13606384001	500209675	SGT	TI8	46079	1333028	15,107.81	TI8	LDS/LGSS
37	13629199001	500199977	SGT	TIF	46006	1112521	38,461.32	TIF	LDS/LGSS
37	13648145002	400473252	SC2		1289	1112521	24,071.02	SC2	SGSS2/SCD2/SGDS2
37	13676826001	500220820	SGT	845	46101	30243	27,319.26	845	FLEX
37	13801660001	500224592	SGT	TAG6	46122	1292998	17,889.42	TAG6	SGSS2/SCD2/SGDS2
37	13807449005	500843197	SGT	TAG6	48733	10160	10,929.56	TAG6	SGSS2/SCD2/SGDS2
37	13953098002	500268352	SG4		46701	511314	2,164.21	SG4	SGSS2/SCD2/SGDS2
37	13959263001	400473271	SGT	TI8	1309	1292977	9,426.78	TI8	LDS/LGSS
37	13968541002	500296548	SGT	TM3	46567	511324	286,814.93	TM3	MDS/NSS
37	14012426004	400516863	SG2		761	30272	1,160.93	SG2	SGSS2/SCD2/SGDS2
37	14161126001	400472230	SGT	TIB	3588	1333034	4,042.39	TIB	SDS/LGSS

37	14172457001	500278290	SGT	TAG6	46926	273804	233.25	TAG6	SGSS2/SCD2/SGDS2
37	14203427002	400483822	SGT	TAG6	14283	511304	7,594.01	TAG6	SGSS2/SCD2/SGDS2
37	14238571001	500337814	SGT	TIF	46961	1333007	9,157.29	TIF	LDS/LGSS
37	14303963001	500391455	SGT	TI4	47285	30260	12,062.59	TI4	SDS/LGSS
37	14313747005	500338294	SGT	TAG6	47466	10155	12,751.38	TAG6	SGSS2/SCD2/SGDS2
37	14318082003	400519776	SGT	TIB	47451	1333032	12,859.08	TIB	SDS/LGSS
37	14344230001	500212008	SGT	TIB	47252	1252822	11,414.42	TIB	SDS/LGSS
37	14351364003	500354179	SGT	TIB	47333	591705	(9,801.11)	TIB	SDS/LGSS
37	14351364003	500371709	SGT	TIB	47605	591705	10,935.22	TIB	SDS/LGSS
37	14351364003	500690713	SGT	TIB	49040	591705	6,003.16	TIB	SDS/LGSS
37	14471914001	400526560	SGT	TIF	3908	1333032	13,405.54	TIF	LDS/LGSS
37	14492769002	500965975	LG3		49158	1112521	15,825.73	LG3	LDS/LGSS
37	14529317003	400472635	SGT	840	1139	1252856	13,865.46	840	FLEX
37	14529317003	800800373	SGT	840	14246	1252856	13,412.22	840	FLEX
37	14557113003	500054098	SGT	TI4	48084	551501	30,701.18	TI4	SDS/LGSS
37	14623990006	400526769	SG2		4505	1333095	1,505.78	SG2	SGSS2/SCD2/SGDS2
37	14738217002	400473525	SG4		621	832206	5,915.22	SG4	SGSS2/SCD2/SGDS2
37	14860718003	400473280	SGT	TAG6	1313	511314	14,364.41	TAG6	SGSS2/SCD2/SGDS2
37	14958276004	501161721	SGT	TIB	49323	1112501	31,261.72	TIB	SDS/LGSS
37	14962898001	400504012	SC2		4067	10104	1,319.79	SC2	SGSS2/SCD2/SGDS2
37	14997023001	400472421	SGT	TAG6	3491	10157	2,370.57	TAG6	SGSS2/SCD2/SGDS2
37	15096104001	500587558	SGT	809	47842	732195	6,753.16	809	FLEX
37	15096104002	501033523	SGT	809	49045	732195	44,763.53	809	FLEX
37	15096113001	500587559	SGT	833	47843	732195	45,474.89	833	FLEX
37	15107817004	500136220	SG4		1438	511314	1,652.12	SG4	SGSS2/SCD2/SGDS2
37	15120198003	501174545	LG2		49367	1333032	64,145.58	LG2	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	15310256001	400477241	SGT	TIB	3990	1333017	60.31	TIB	SDS/LGSS
37	15320799002	400514006	SGT	TAG6	4540	1252822	0.00	TAG6	SGSS2/SCD2/SGDS2
37	15386979001	400472009	SGT	TIB	3788	1333027	4,470.87	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	2,282.29	SG2	SGSS2/SCD2/SGDS2
37	15514483001	400473294	SG2		1329	1112521	1,293.77	SG2	SGSS2/SCD2/SGDS2
37	15514517001	500607489	SGT	TIF	48514	551504	29,232.95	TIF	LDS/LGSS
37	15614278001	500732771	SGT	TI4	48561	30223	5,320.06	TI4	SDS/LGSS
37	15630675002	501155646	SG2		49311	1292909	46,337.79	SG2	SGSS2/SCD2/SGDS2
37	15632066001	500494320	SGT	TI4	48533	1112512	13,388.88	TI4	SDS/LGSS
37	15641400003	400502082	LG1		46814	1333017	12,842.45	LG1	SDS/LGSS
37	15674018001	500648810	SGT	TIF	48541	273801	100,011.17	TIF	LDS/LGSS
37	15878297001	500766884	SGT	TI4	48455	1333007	2,215.93	TI4	SDS/LGSS
37	15886667015	400472089	SG4		3897	1333032	4,697.05	SG4	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	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	16266565001	400518893	SGT	TIB	934	70495	1,261.32	TIB	SDS/LGSS
37	16316862001	400489632	SGT	TIB	48727	10103	23,457.97	TIB	SDS/LGSS
37	16450594001	400526719	SGT	TIB	48743	1333083	6,816.35	TIB	SDS/LGSS
37	16630957002	400526998	SGT	TMB	14788	70470	33,446.59	TMB	MDS/NSS
37	16656334003	501222616	LG1		49396	511304	26,053.55	LG1	SDS/LGSS
37	16804444002	500146391	SGT	TI8	861	70495	5,786.00	TI8	LDS/LGSS
37	16804444008	500175309	SGT	TIB	49139	70495	21,018.66	TIB	SDS/LGSS
37	16919869001	500215263	SGT	TAG6	48787	1333095	14,904.77	TAG6	SGSS2/SCD2/SGDS2
37	16920048001	500959190	SGT	TIB	48797	511395	9,062.42	TIB	SDS/LGSS
37	17000719005	400496375	SGT	TAG6	14550	1333027	1,701.93	TAG6	SGSS2/SCD2/SGDS2
37	17037445001	500962866	SGT	TIB	48814	511306	18,913.52	TIB	SDS/LGSS
37	17097990001	400473352	SCC		4547	1252858	1,965.53	SCC	SGSS1/SCD1/SGDS1

37	17184483002	500193058	SGT	TIB	45604	732195	(5,006.09)	TIB	SDS/LGSS
37	17187387006	400471902	SGT	TI8	4178	1333032	6,490.58	TI8	LDS/LGSS
37	17230495003	400479417	SG2		888	30225	1,962.15	SG2	SGSS2/SCD2/SGDS2
37	17264884002	400500238	SGT	TIH	14403	1333032	13,842.91	TIH	LDS/LGSS
37	17297010001	400474558	SGT	TI4	14055	1333035	8,795.26	TI4	SDS/LGSS
37	17329614003	500162630	SGT	868	44642	1333027	12,763.43	868	FLEX
37	17329614003	500162631	SGT	868	44642	1333027	12,763.43	868	FLEX
37	17374299002	400473323	LG2		1351	511314	9,043.84	LG2	SDS/LGSS
37	17409498001	501027922	SGT	TIB	49021	1333095	13,667.74	TIB	SDS/LGSS
37	17432474003	400472075	SGT	TIB	3879	1333027	0.00	TIB	SDS/LGSS
37	17439660001	400471850	SGT	TI4	4149	1333035	290.07	TI4	SDS/LGSS
37	17439660003	800800314	SGT	TAG2	4269	1333035	2,430.25	TAG2	SGSS2/SCD2/SGDS2
37	17446577006	400498963	SGT	TI8	14518	10160	5,361.20	TI8	LDS/LGSS
37	17451537003	400473024	SG2		862	30272	142.84	SG2	SGSS2/SCD2/SGDS2
37	17486118001	501043836	SG4		49030	273821	13,756.34	SG4	SGSS2/SCD2/SGDS2
37	17509433003	501049268	SGT	TI8	49070	511306	17,829.30	TI8	LDS/LGSS
37	17556648001	500988325	LG1		49016	1252829	60,036.77	LG1	SDS/LGSS
37	17613477001	501040193	SG2		49048	832295	17,028.50	SG2	SGSS2/SCD2/SGDS2
37	17662964001	400472829	SGT	TIB	711	30252	8,688.26	TIB	SDS/LGSS
37	17692241009	501080986	SGT	TIB	49302	1333017	65,532.25	TIB	SDS/LGSS
37	17766386001	501049150	SGT	TI8	49088	1333014	35,922.76	TI8	LDS/LGSS
37	18505018001	400473396	SG2		3248	1292914	1,663.84	SG2	SGSS2/SCD2/SGDS2
37	18540737001	500487109	SGS		47705	1292909	31,397.65	SGS	SGSS1/SCD1/SGDS1
37	18553656003	500204877	SG2		48298	30272	5,399.51	SG2	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	5,166.94	TIF	LDS/LGSS
37	18792064002	501099066	SGT	TAG6	49244	1333035	15,923.45	TAG6	SGSS2/SCD2/SGDS2
37	18836110001	400473205	SGT	TIB	1018	732111	3,880.29	TIB	SDS/LGSS
37	18885421001	500376080	SGT	TIB	49156	10119	16,178.78	TIB	SDS/LGSS
37	18897692003	400472409	SGT	TIB	1512	10160	1,660.38	TIB	SDS/LGSS
37	18941652003	400473297	SGS		1332	511318	3,863.92	SGS	SGSS1/SCD1/SGDS1
37	18973174002	400526191	SGT	873	44761	190613	52,867.22	873	FLEX
37	18985473001	501047288	SGT	TIB	49243	1333035	403.68	TIB	SDS/LGSS
37	18988904003	501281830	LG1		49425	70479	30,721.08	LG1	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	944.86	TIB	SDS/LGSS
37	19074397001	501115733	SGT	TI8	49265	1333017	1,216.31	TI8	LDS/LGSS
37	19075101001	400473322	SG2		4421	1292916	10,041.93	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	15,084.85	TIG	LDS/LGSS
37	19193822001	501050977	SGT	TI4	49272	10103	17,467.57	TI4	SDS/LGSS
37	19252407003	800800378	SGT	TAG6	849	30234	2,908.76	TAG6	SGSS2/SCD2/SGDS2
37	19336466001	400501188	SGT	TI4	45609	1333032	43,301.57	TI4	SDS/LGSS
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	4,780.17	SG2	SGSS2/SCD2/SGDS2
37	19443642001	400472814	SGT	TIB	697	70403	8,081.85	TIB	SDS/LGSS
37	19447200001	400472448	LG2		4581	273851	1,746.45	LG2	SDS/LGSS
37	19447200003	500153394	LG1		4581	273851	1,746.45	LG1	SDS/LGSS
37	19451537002	501178063	LG2		49337	1112521	16,774.06	LG2	SDS/LGSS
37	19531601001	400526383	SG3		1012	30225	11,525.34	SG3	SGSS1/SCD1/SGDS1
37	19592009003	501149161	LG2		49340	1252822	15,220.72	LG2	SDS/LGSS
37	19623332001	400472345	SG2		3562	1333063	7,786.78	SG2	SGSS2/SCD2/SGDS2
37	19682099001	500296730	SGT	TI4	46707	511304	26,053.55	TI4	SDS/LGSS
37	19791817001	500175440	SGT	TAG5	45528	70452	31,330.69	TAG5	SGSS1/SCD1/SGDS1
37	19817465001	400472437	SG2		3304	10104	8,152.83	SG2	SGSS2/SCD2/SGDS2
37	19845214005	400472052	SGT	TIB	3847	1333032	7,490.23	TIB	SDS/LGSS
37	19854159001	501154755	SGT	TI8	49338	273804	2,245.53	TI8	LDS/LGSS

37	19854159002	501162824	LG2		49322	1333029	5,990.82	LG2	SDS/LGSS
37	19866613001	501025433	SGT	TIB	48841	190626	21,082.43	TIB	SDS/LGSS
37	19968875005	800800311	SGT	TIB	14595	1333029	3,083.07	TIB	SDS/LGSS
37	20091569037	400479518	SGT	TAG6	774	30272	1,641.60	TAG6	SGSS2/SCD2/SGDS2
37	20159378001	500153126	SGT	TI8	45642	70479	635.10	TI8	LDS/LGSS
37	20231700001	400472742	SGT	TI4	14101	1252807	5,736.00	TI4	SDS/LGSS
37	20231700003	400472014	SGT	TIB	3795	1333027	8,044.15	TIB	SDS/LGSS
37	20233976002	400473233	SG2		1275	511311	1,137.23	SG2	SGSS2/SCD2/SGDS2
37	20260616001	400500097	SGT	TM1	14666	10119	3,535.27	TM1	MDS/NSS
37	20271953001	500214064	LG2		47053	1252822	26,943.19	LG2	SDS/LGSS
37	20271953003	500459284	LG1		47484	1252822	5,248.14	LG1	SDS/LGSS
37	20352622001	400493366	SGT	TIF	14458	1333025	4,349.04	TIF	LDS/LGSS
37	20403776001	501228775	SG2		49390	10157	3,188.39	SG2	SGSS2/SCD2/SGDS2
37	20428036001	400494812	SG2		14520	1333095	3,163.10	SG2	SGSS2/SCD2/SGDS2
37	20436639001	400516841	SC2		671	30272	860.03	SC2	SGSS2/SCD2/SGDS2
37	20460679003	400472903	SG2		775	732195	1,532.00	SG2	SGSS2/SCD2/SGDS2
37	20480473001	501093555	SGT	880	49361	1333014	467,690.79	880	FLEX
37	20480473002	400471977	SGT	TIB	4335	1333077	5,839.08	TIB	SDS/LGSS
37	20503074001	501173051	SGT	TIB	49398	1333029	2,795.00	TIB	SDS/LGSS
37	20540367001	501221207	SGT	810	49395	732195	32,565.34	810	FLEX
37	20556961001	400494798	SGT	TI8	14599	10160	3,955.51	TI8	LDS/LGSS
37	20665631001	400473191	SGT	TIF	1007	30225	5,974.11	TIF	LDS/LGSS
37	20669499001	501163330	SGT	TIB	49411	70452	31,330.69	TIB	SDS/LGSS
37	20688663001	400474751	SGT	TI4	4509	30223	3,241.16	TI4	SDS/LGSS
37	20721676001	400472176	LG2		3969	1333095	7,763.66	LG2	SDS/LGSS
37	20731842001	400473264	SG2		1303	511314	1,557.22	SG2	SGSS2/SCD2/SGDS2
37	20733007001	400473253	LG2		1290	1292977	10,041.96	LG2	SDS/LGSS
37	20733007003	400288865	SG4		46395	1292977	2,014.58	SG4	SGSS2/SCD2/SGDS2
37	20733007004	400289580	SG4		46393	1292977	2,014.58	SG4	SGSS2/SCD2/SGDS2
37	20757032003	400471986	SGT	TAG6	3754	1333017	1,646.10	TAG6	SGSS2/SCD2/SGDS2
37	20875641001	400473354	LG2		1377	1292913	936.34	LG2	SDS/LGSS
37	20886128001	400516474	SGT	TIB	3863	1333029	12,486.40	TIB	SDS/LGSS
	Total								

	Total Cost	**Percent**
RSS/RTS	**0.00**	**0.000%**
SGSS1/SCD1/SGDS1	**81,966.67**	**1.596%**
SGSS2/SCD2/SGDS2	**712,666.88**	**13.872%**
SDS/LGSS	**1,742,719.49**	**33.923%**
LDS/LGSS	**1,745,448.70**	**33.976%**
FLEX	**854,489.86**	**16.633%**
TOTAL BEFORE MDS/NSS	**5,137,291.60**	**100.000%**
MDS/NSS	**473,035.29**	
FLEX MDS	**25,106.50**	
TOTAL	**5,635,433.39**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 18
OTHER DISTRIBUTION O & M EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	871.00	LOAD DISPATCHING	290,954	222,772	24,158	19,040	9,599	7,731	18	7,638
2	874.00	MAINS & SERVICES	22,963,878	18,397,970	1,844,688	1,214,330	583,971	464,100	1,148	457,670
3	875.00	M & R - GENERAL	1,000,400	765,966	83,063	65,466	33,003	26,581	60	26,261
4	876.00	M & R - INDUSTRIAL	382,620	-	6,107	53,077	129,796	129,999	-	63,641
5	878.00	METERS & HOUSE REGULATORS	2,274,895	1,791,753	298,489	157,719	21,225	4,459	228	1,024
6	879.00	CUSTOMER INSTALLATIONS	7,286,676	6,636,486	524,641	102,742	15,302	4,445	-	3,060
7	886.00	STRUCTURES AND IMPROVEMENT	82,677	63,302	6,865	5,410	2,728	2,197	5	2,170
8	887.00	MAINS	18,854,683	14,436,277	1,565,504	1,233,851	622,016	500,969	1,131	494,935
9	889.00	M & R - GENERAL	1,227,716	940,013	101,937	80,342	40,502	32,620	74	32,228
10	890.00	M & R - INDUSTRIAL	177,871	-	2,839	24,674	60,339	60,434	-	29,585
11	892.00	SERVICES	3,535,898	3,220,390	254,585	49,856	7,425	2,157	-	1,485
12	893.00	METERS & HOUSE REGULATORS	1,032,820	813,470	135,516	71,605	9,636	2,024	103	465
13		TOTAL	59,111,088	47,288,398	4,848,392	3,078,112	1,535,543	1,237,715	2,767	1,120,162
14		**ALLOCATOR #18**	100.000%	79.999%	8.202%	5.207%	2.598%	2.094%	0.005%	1.895%

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	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1		TOTAL PURCH GAS & UNDERGROUND STORAGE	162,957,347	120,793,944	18,175,736	19,903,319	3,691,732	170,037	222,579	-
2		TOTAL DISTRIBUTION O&M [2]	73,601,022	58,880,201	6,036,856	3,832,603	1,911,991	1,541,134	3,491	1,394,746
3		TOTAL CUSTOMER ACCOUNTS [3]	42,920,388	41,151,015	892,021	362,022	251,249	215,875	13,617	34,588
4		TOTAL CUSTOMER SERVICE & INFORMATION [4]	2,047,710	1,875,108	143,647	26,190	2,273	348	41	103
5		TOTAL SALES [5]	456,184	417,732	32,001	5,835	506	78	9	23
6		TOTAL	281,982,651	223,118,000	25,280,261	24,129,969	5,857,752	1,927,472	239,737	1,429,460
	LESS:									
7		GAS PURCHASED COST [6]	161,368,307	119,615,901	17,998,184	19,709,532	3,655,831	168,466	220,393	-
8	904.00	UNCOLLECTIBLES-DIS REVENUE [7]	6,235,204	5,800,673	222,285	212,246	-	-	-	-
9	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE [8]	482,584	(0)	217	13,135	241,421	214,370	13,440	34,146
10	904.00	UNCOLLECTIBLES-UNBUNDLED GAS [9]	782,615	739,685	21,461	21,469	-	-	-	-
11	904.00	DIRECT USP UNCOLLECTIBLES [10]	26,432,574	26,432,574	-	-	-	-	-	-
12		TOTAL	195,301,284	152,588,833	18,242,147	19,956,383	3,897,252	382,836	233,833	34,146
13		TOTAL	86,681,368	70,529,168	7,038,114	4,173,586	1,960,500	1,544,636	5,904	1,395,314
14		**ALLOCATOR #19**	100.000%	81.404%	8.120%	4.815%	2.262%	1.782%	0.007%	1.610%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2020

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND WITNESS: C. E. Notestone

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	FLEX
			Footage	Amount	Unit Cost				
1	2" Pipe		14,572,470	297,350,015	$20.40				
2	All Pipe		41,023,960	1,544,125,441					
3	Unit Cost of 2" x All Pipe Footage			836,888,784					
4	Customer Component			54.198%					
5	Demand Component			45.802%					
6	Number of Customers (Total Company excl MDS)		444,012	406,599	31,147	5,677	492	74	23
7	Percent Customers		100.000%	91.572%	7.015%	1.279%	0.111%	0.017%	0.006%
8	Customer Component		54.198%	49.634%	3.802%	0.693%	0.060%	0.009%	0.003%
9	Design Day Volumes (Total Company excl MDS)		790,500	465,000	77,700	101,000	55,900	45,700	45,200
10	Percent Design Day Volumes		100.000%	58.824%	9.829%	12.777%	7.071%	5.781%	5.718%
11	Demand Component		45.802%	26.942%	4.502%	5.852%	3.239%	2.648%	2.619%
12	**Minimum System Allocation Factor**		**100.000%**	**76.573%**	**8.304%**	**6.545%**	**3.299%**	**2.657%**	**2.622%**

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 21
HOUSE REGULATORS

All Customers Excluding Low Pressure Customers

LINE NO.	Rate	RS/RTS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS	FLEX	TOTAL
1	RC2	240,056	0	0	0	0	0	0	240,056
2	RS	2,534,519	0	0	0	0	0	0	2,534,519
3	RTC	450,812	0	0	0	0	0	0	450,812
4	LG1	0	0	0	548	0	0	0	548
5	LG2	0	0	0	462	0	0	0	462
6	LG3	0	0	0	0	12	0	0	12
7	LG4	0	0	0	0	12	0	0	12
8	NSI	0	0	0	0	0	12	0	12
9	SGS	0	170,062	0	0	0	0	0	170,062
10	SG2	0	0	26,355	0	0	0	0	26,355
11	SG3	0	233	0	0	0	0	0	233
12	SG4	0	0	448	0	0	0	0	448
13	TAG1	0	1,149	0	0	0	0	0	1,149
14	TAG2	0	0	2,895	0	0	0	0	2,895
15	TAG5	0	6,263	0	0	0	0	0	6,263
16	TAG6	0	0	12,706	0	0	0	0	12,706
17	TIB	0	0	0	2,604	0	0	0	2,604
18	TIF	0	0	0	0	324	0	0	324
19	TIG	0	0	0	0	72	0	0	72
20	TIH	0	0	0	0	12	0	0	12
21	TI4	0	0	0	2,153	0	0	0	2,153
22	TI8	0	0	0	0	468	0	0	468
23	TMA	0	0	0	0	0	0	0	0
24	TM1	0	0	0	0	0	24	0	24
25	TM2	0	0	0	0	0	0	0	0
26	TM3	0	0	0	0	0	12	0	12
27	TMB	0	0	0	0	0	36	0	36
28	TMC	0	0	0	0	0	12	0	12
29	808	0	0	0	0	0	0	12	12
30	809	0	0	0	0	0	0	24	24
31	810	0	0	0	0	0	0	24	24
32	816	0	0	0	0	0	0	12	12
33	833	0	0	0	0	0	0	12	12
34	838	0	0	0	0	0	0	0	0
35	840	0	0	0	0	0	0	12	12
36	841	0	0	0	0	0	0	0	0
37	845	0	0	0	0	0	0	12	12
38	846	0	0	0	0	0	0	12	12
39	847	0	0	0	0	0	0	12	12
40	848	0	0	0	0	0	0	0	0
41	856	0	0	0	0	0	0	0	0
42	857	0	0	0	0	0	0	12	12
43	858	0	0	0	0	0	0	0	0
44	859	0	0	0	0	0	0	0	0
45	868	0	0	0	0	0	0	12	12
46	872	0	0	0	0	0	0	1	1
47	873	0	0	0	0	0	0	12	12
48	874	0	0	0	0	0	0	0	0
49	875	0	0	0	0	0	0	12	12
50	876	0	0	0	0	0	0	12	12
51	877	0	0	0	0	0	0	12	12
52	879	0	0	0	0	0	0	12	12
53	880	0	0	0	0	0	0	12	12
54	881	0	0	0	0	0	0	12	12
55	SCC	0	62,011	0	0	0	0	0	62,011
56	SC2	0	0	11,509	0	0	0	0	11,509
57	**Total**	**3,225,387**	**239,718**	**53,913**	**5,767**	**900**	**96**	**241**	**3,526,022**
58	**ALLOCATOR #21**	91.472%	6.799%	1.529%	0.164%	0.026%	0.003%	0.007%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 22
AVERAGE ALLOCATORS 5 & 20

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX	TOTAL
1	ALLOCATOR #5	52.014%	8.606%	12.258%	8.427%	10.145%	8.550%	100.000%
2	ALLOCATOR #20	76.573%	8.304%	6.545%	3.299%	2.657%	2.622%	100.000%
3	TOTAL OF BOTH STUDIES	128.587%	16.910%	18.803%	11.726%	12.802%	11.172%	
4	AVERAGE OF BOTH STUDIES	64.294%	8.455%	9.402%	5.863%	6.401%	5.586%	100.000%
5	**ALLOCATOR #22**	64.294%	8.455%	9.402%	5.863%	6.401%	5.586%	100.000%

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	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	381.00	METERS	42,969,482	32,988,531	6,144,636	3,405,331	333,443	78,205	3,008	16,328
2	381.10	AUTOMATIC METER READING	24,684,074	18,950,457	3,529,823	1,956,213	191,548	44,925	1,728	9,380
3	381.10	AUTOMATIC METER READING	404,440	-	-	-	333,307	50,130	5,420	15,583
4	382.00	METER INSTALLATIONS	44,125,107	33,875,727	6,309,890	3,496,915	342,411	80,308	3,089	16,768
5	383.00	HOUSE REGULATORS	16,515,236	15,106,816	1,122,871	252,518	27,085	4,294	496	1,156
6	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,187,606	236,931	53,282	5,715	906	105	244
7		TOTAL	132,183,126	104,109,137	17,344,150	9,164,259	1,233,510	258,768	13,844	59,459
8		**ALLOCATOR #23**	100.000%	78.762%	13.121%	6.933%	0.933%	0.196%	0.010%	0.045%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 24
LABOR

LINE NO.	ACCT. NO.	ACCOUNT	ALLOC FACTOR	TOTAL COMPANY	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	816.00	WELLS	25	-	-	-	-	-	-	-	-
2	817.00	LINES	25	-	-	-	-	-	-	-	-
3	818.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-	-
4	820.00	M & R	25	65,391	48,598	7,566	7,737	1,393	-	97	-
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	4,038,213	3,230,530	331,214	210,270	104,913	84,560	202	76,524
10	871.00	LOAD DISPATCHING	13	206,855	158,381	17,175	13,537	6,824	5,496	12	5,430
11	874.00	MAINS & SERVICES	14	9,521,470	7,628,316	764,860	503,495	242,131	192,429	476	189,763
12	875.00	M & R - GENERAL	13	367,270	281,204	30,494	24,034	12,116	9,758	22	9,641
13	876.00	M & R - INDUSTRIAL	17	218,157	(0)	3,482	30,263	74,005	74,121	-	36,286
14	878.00	METERS & HOUSE REGULATORS	23	1,220,959	961,652	160,202	84,649	11,392	2,393	122	549
15	879.00	CUSTOMER INSTALLATIONS	15	4,687,734	4,269,448	337,517	66,097	9,844	2,860	-	1,969
16	880.00	OTHER	18	2,607,571	2,086,030	213,873	135,776	67,745	54,603	130	49,414
17	885.00	SUPERVISION & ENGINEERING	18	145,273	116,217	11,915	7,564	3,774	3,042	7	2,753
18	886.00	STRUCTURES AND IMPROVEMENTS	13	18,314	14,023	1,521	1,199	604	487	1	481
19	887.00	MAINS	13	4,213,303	3,225,958	349,831	275,719	138,997	111,948	253	110,599
20	889.00	M & R - GENERAL	13	693,655	531,104	57,594	45,393	22,884	18,430	42	18,209
21	890.00	M & R - INDUSTRIAL	17	37,756	-	603	5,238	12,808	12,828	-	6,280
22	892.00	SERVICES	15	1,414,805	1,288,562	101,866	19,949	2,971	863	-	594
23	893.00	METERS & HOUSE REGULATORS	23	575,459	453,243	75,506	39,897	5,369	1,128	58	259
24	894.00	OTHER EQUIPMENT	18	582,208	465,760	47,753	30,316	15,126	12,191	29	11,033
25	902.00	METER READING	6	253,477	232,111	17,781	3,242	281	43	5	13
26	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSES	6	678,981	621,749	47,631	8,684	754	115	14	34
25	920.00	SALARIES	19	4,198,858	3,417,745	341,073	202,259	95,020	74,866	294	67,602
26	921.00	OFFICE SUPPLIES & EXPENSES	19	584,621	475,864	47,489	28,161	13,230	10,424	41	9,412
27	923.00	OUTSIDE SERVICES EMPLOYED	19	-	-	-	-	-	-	-	-
28		TOTAL		36,330,329	29,506,494	2,966,945	1,743,477	842,181	672,584	1,805	596,843
29		**ALLOCATOR #24**		100.000%	81.217%	8.167%	4.799%	2.318%	1.851%	0.005%	1.643%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 26
C&I NETWORK CUSTOMERS

	RSS/RDS	SGS-1	SGS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	Total
Allocation Factor #6	406,599	31,147	5,677	492	74	8	23	444,020
Less: Residential Customers	(406,599)	0	0	0	0	0	0	(406,599)
Less: SGSS1/SCD1/SGDS1	0	(31,147)	0	0	0	0	0	(31,147)
Less: SGSS2/SCD2/SGDS2	0	0	(5,677)	0	0	0	0	(5,677)
Total	0	0	0	492	74	8	23	597
ALLOCATOR #26	0.000%	0.000%	0.000%	82.412%	12.395%	1.340%	3.853%	100.000%

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 involve 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 CEN-1 for a detailed description of Factor Nos. 5 and 20.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Direct Mains

Mains for Main Line Delivery Service ("MLDS") 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 MLDS 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 MLDS 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 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 is based on number of customers by rate class that are not served from a low pressure main. Because customers served off low pressure mains do not require a House Regulator, those customers are not included in the allocation factor as explained in Statement No. 11.

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 Distributive Information System ("DIS"). This methodology represents 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 projected future test year and supported by Witness Mays.

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 the twelve months ended November 30, 2019.

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

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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 projected future test 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

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, because 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 because these are costs incurred monitoring and directing the flow of gas through the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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 because 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 - because these costs are incurred in direct association with the stations in Account 385.

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 - because these costs benefit customers in the same way that all other distribution costs provide benefit.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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, because plant and expense functions are directly related.

Accounts 889

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures because 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 - because 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 explained 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.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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

These costs were directly assigned to each rate schedule matching revenue for the fully projected future test 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 projected future test 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, because 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, because all customers may benefit except account 908 – Direct USP/LIURP/HEEP. These costs include the recovery of

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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, because these activities directly support customers served.

ADMINISTRATIVE AND GENERAL EXPENSES - PAGE 8

Admin. & General Expenses (Line 33)

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, because they are directly related to company labor. Account 923 – Multifamily House Line Reimbursement costs are a 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

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

were allocated using Factor 19 because these taxes are generally related to the purchase of supplies.

RATE BASE SUMMARY - PAGE 10

Account 154

Materials and Supplies were allocated based on No. 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 No. 19, Total O&M Excluding Gas Purchased Costs, A&G, Uncollectibles, and USP Rider Costs. The exception being Cloud Based Assets that, like 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.

Accounts 190, 282 and 283

All deferred income taxes included in rate base are plant related and, therefore, Factor No. 12, Gross Plant, was used.

Account 235

Customer Deposits were allocated using Factor No. 9, Direct Assignment – Customer Deposits.

Accounts 252 and 186

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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.

FEDERAL AND STATE INCOME TAX - PAGE 11

All of the Company's tax adjustments 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 Pennsylvania, Inc.
Intra Class Adjustment from SGDS to SGSS and SCD at Proposed ROE of 10.95%
For the 12 Months Ending December 31, 2022

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,631,226	2,698,691	420,133	429,647	77,345	-	5,411
2	Account 164	34,854,214	25,903,303	4,032,633	4,123,951	742,395	-	51,933
3	Allocated Storage Per ACOS Study using Allocation Factor #25	38,485,440	28,601,994	4,452,765	4,553,597	819,740	-	57,343
4	Sales & CHOICE Transportation (Ditch)	46,614,960.9	34,643,463.1	5,393,499.4	5,515,384.1	993,014.3	0.0	69,600.0
5	Factor 25 Allocation of Storage	100%	74.319%	11.570%	11.832%	2.130%	0.000%	0.149%
6	Pre-Tax as Filed	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	3,963,778	2,945,840	458,609	468,994	84,428	-	5,906
8	Rate Per Ditch	0.0850						
9					Included			
10			Total	% of	In Proposed		Redistributed	
11			DTH	Total	Rates	Ratio	Per Settlement	
12								
13	SGSS1 - Subject to Storage		3,901,993.9	68.990%	316,394	0.7235	15,363	
14	SCD1 - Subject to Storage		1,491,505.5	26.370%	120,935	0.2765	5,871	
15	SGDS1 - Not Subject to Storage		262,006.4	4.630%	21,234		(21,234)	
			5,655,505.8	99.990%	458,563		0	
16					Included			
17			Total	% of	In Proposed		Redistributed	
18			DTH	Total	Rates	Ratio	Per Settlement	
19								
20	SGSS2 - Subject to Storage		3,903,397.1	43.400%	203,543	0.7078	128,367	
21	SCD2 - Subject to Storage		1,611,987.0	17.920%	84,044	0.2922	52,993	
22	SGDS2 - Not Subject to Storage		3,477,754.6	38.670%	181,360		(181,360)	
			8,993,138.7	99.990%	468,947		0	

Unitized Returns at Current Rates and Proposed Rates

Ln.	Study (Mains Allocation Method)	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	Peak & Average Current Rates	1.26	1.08	1.14	0.95	0.17	30.41	(0.84)
2	Peak & Average Proposed Rates	1.22	1.06	1.08	1.00	0.38	20.00	(0.55)
3	Customer/Demand Current Rates	0.72	1.14	2.87	3.92	3.60	30.41	(0.31)
4	Customer/Demand Proposed Rates	0.77	1.11	2.46	3.50	3.36	20.00	(0.20)
5	Average of P/A & C/D Current Rates	0.95	1.11	1.77	1.81	0.90	30.41	(0.72)
6	Average of P/A & C/D Proposed Rates	0.96	1.08	1.57	1.72	1.01	20.00	(0.47)

		Amount	Rate	
1	**Labor and Benefits** [1]	**Amount**	**Rate**	
2	Accounting Support	$4,531.43		
3	Gas Supply Support	$203,428.42		
4	Legal Support	$5,685.68		
5	Regulatory Support	$84,506.70		
6	Treasury Support	$11,999.46		
7	**Total Labor and Benefits (Line 2 + Line 3 + Line 4 + Line 5 + Line 6)**	**$310,151.69**		
8	**Outside Services - Legal Support**	**$61,000.00**		
9	**Information Technology Systems Maintenance**			
10	Gas Source	$49,021.00		
11	% of customers taking Sales Service	80.00%		
12	**Cost allocated to Sales Service Customers (line 10 * Line 11)**	**$39,216.80**		
13	**TOTAL (line 6 + line 8 + line 9)**	**$410,368.49**		
14	Total Sales (Therms)	362,959,766 [2]		
15	Gas Procurement Charge (Line 13 / Line 14)		$0.00113	per / therm
16	Gas Procurement Charge (Line 15 * 10)		$0.01130	per / Dth

(1) Labor charges include payroll, benefits and taxes.

(2) Fully Projected Future Test Year Gas Service Sales per Exhibit 103, Sch. 1, Page 14, Line 49, less Rate NSS Sales as NSS is not subject to GPC.

Columbia Gas of Pennsylvania, Inc.
Benchmark Distribution Revenue per Bill (BDRB)
For the 12 Months Ending December 31, 2022

Number of Bills

	Residential FPFTY RS	Residential RDS FPFTY	Residential RS Final Bills	Residential RDS Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	329,203	56,712	3,317	295	0	(177)	389,350
February	330,067	56,356	3,952	314	279	(177)	390,791
March	330,684	55,954	4,104	310	518	(177)	391,393
April	329,996	55,511	3,491	298	672	(177)	389,791
May	328,948	55,098	3,519	282	820	(176)	388,491
June	327,718	54,752	3,933	308	920	(175)	387,456
July	327,026	54,388	5,206	441	1,116	(175)	388,002
August	326,833	54,107	5,664	437	1,974	(175)	388,840
September	327,359	53,807	4,904	438	2,320	(175)	388,653
October	328,787	53,502	4,610	432	4,185	(175)	391,341
November	331,477	53,158	4,528	417	4,570	(176)	393,974
December	334,090	54,640	4,363	398	4,257	(177)	397,571
Total	3,952,188	657,985	51,591	4,370	21,631	(2,112)	4,685,653

Volumes (Dth)

	Residential FPFTY RS	Residential RDS FPFTY	Residential RS Final Bills	Residential RDS Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	5,297,753.2	961,909.7	0.0	0.0	2,606.0	(2,904.0)	6,259,364.9
February	5,328,609.5	954,375.6	0.0	0.0	6,906.0	(2,915.0)	6,286,976.1
March	4,536,716.3	806,508.2	0.0	0.0	10,373.0	(2,479.0)	5,351,118.5
April	2,932,424.2	524,474.6	0.0	0.0	11,572.0	(1,604.0)	3,466,866.8
May	1,256,981.3	222,757.4	0.0	0.0	11,931.0	(687.0)	1,490,982.7
June	638,282.0	112,429.8	0.0	0.0	11,254.0	(348.0)	761,617.8
July	342,590.5	59,409.2	0.0	0.0	11,661.0	(187.0)	413,473.7
August	307,370.5	53,001.4	0.0	0.0	17,964.0	(167.0)	378,168.9
September	380,818.4	64,940.3	0.0	0.0	18,782.0	(207.0)	464,333.7
October	603,602.2	105,070.5	0.0	0.0	30,830.0	(329.0)	739,173.7
November	1,815,667.4	309,887.2	0.0	0.0	32,025.0	(986.0)	2,156,593.6
December	3,875,261.8	669,001.0	0.0	0.0	30,512.0	(2,109.0)	4,572,665.8
Total	27,316,077.3	4,843,764.9	0.0	0.0	196,416.0	(14,922.0)	32,341,336.2

Calculation of Benchmark Distribution Revenue per Bill (BDRB)

	Bills	Rate	Customer Based Revenue	Volumes (Dth)	Rate/Dth	Volumetric Based Revenue	BDRB
	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=((3+6)/1)
January	389,350	$ 19.33	$ 7,526,136	6,259,364.9	$ 8.8796	$ 55,580,657	$ 162.08
February	390,791	$ 19.33	$ 7,553,990	6,286,976.1	$ 8.8796	$ 55,825,833	$ 162.18
March	391,393	$ 19.33	$ 7,565,627	5,351,118.5	$ 8.8796	$ 47,515,792	$ 140.73
April	389,791	$ 19.33	$ 7,534,660	3,466,866.8	$ 8.8796	$ 30,784,390	$ 98.31
May	388,491	$ 19.33	$ 7,509,531	1,490,982.7	$ 8.8796	$ 13,239,330	$ 53.41
June	387,456	$ 19.33	$ 7,489,524	761,617.8	$ 8.8796	$ 6,762,861	$ 36.78
July	388,002	$ 19.33	$ 7,500,079	413,473.7	$ 8.8796	$ 3,671,481	$ 28.79
August	388,840	$ 19.33	$ 7,516,277	378,168.9	$ 8.8796	$ 3,357,989	$ 27.97
September	388,653	$ 19.33	$ 7,512,662	464,333.7	$ 8.8796	$ 4,123,098	$ 29.94
October	391,341	$ 19.33	$ 7,564,622	739,173.7	$ 8.8796	$ 6,563,567	$ 36.10
November	393,974	$ 19.33	$ 7,615,517	2,156,593.6	$ 8.8796	$ 19,149,689	$ 67.94
December	397,571	$ 19.33	$ 7,685,047	4,572,665.8	$ 8.8796	$ 40,603,443	$ 121.46
Total	4,685,653.0		$ 90,573,672	32,341,336.2		$ 287,178,129	$ 965.69
BDRBp (Oct-Mar)							$ 690.49
BDRBo (Apr-Sep)							$ 275.20

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAp")
Peak Period RNAp Effective October 2022 through March 2023

Line No.		Line Applications	Oct	Nov	Dec	Jan	Feb	Mar	Jan - Mar
	Non-CAP Residential Customers:								
1	**Benchmark Distribution Revenue per Bill ("BDRBp")**								Three month
2		Per Docket							BDRBp
3	Monthly BDRBp	R-2021-3024296	$ 36.10	$ 67.94	$ 121.46	$ 162.08	$ 162.18	$ 140.73	$ 464.99
4									
5	**Actual Distribution Revenue per Bill ("ADRBp")**								Three month
6									ADRBp
7	Monthly ADRBp*	Jan 2022 - Mar 2022	NA	NA	NA	$ 160.00	$ 159.00	$ 139.00	$ 458.00
8									Total
9	Monthly BDRBp - Monthly ADRBp	ln 3 - ln 7				$ 2.08	$ 3.18	$ 1.73	$ 6.99
10									
11	**Actual Number of non-CAP residential Bills ("ANBp")**								
12									Average ANBp
13	Monthly ANBp*		NA	NA	NA	381,820	383,014	383,821	382,885
14									
15									
16	**Revenue to be Assigned to RNAp Rate**					$ 794,185.60	$ 1,217,984.52	$ 664,010.33	$ 2,676,366.15
17									
18	**Forecast Decatherms (Dth) for Effective RNAp Period (FTp)***		739,174	2,156,594	4,572,666	6,259,365	6,286,976	5,351,119	25,365,893
19									
20	**RNAp Rate Effective October 2022 through March 2023**	ln 16 / ln 18							$ 0.1055

* For illustrative purposes only.

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAo")
Off-Peak Period RNAo Effective April 2023 through September 2023

Line No.		Line Applications	Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
	Non-CAP Residential Customers:								
1	**Benchmark Distribution Revenue per Bill ("BDRBo")**								
2		Per Docket							Total BDRBo
3	Monthly BDRBo	R-2021-3024296	$ 98.31	$ 53.41	$ 36.78	$ 28.79	$ 27.97	$ 29.94	$ 275.20
4									
5	**Actual Distribution Revenue per Bill ("ADRBo")**								
6									Total ADRBo
7	Monthly ADRBo*		$ 100.00	$ 54.00	$ 35.00	$ 26.00	$ 30.00	$ 32.00	$ 277.00
8									Total
9	Monthly BDRBo - Monthly ADRBo	ln 3 - ln 7	$ (1.69)	$ (0.59)	$ 1.78	$ 2.79	$ (2.03)	$ (2.06)	$ (1.80)
10									
11	**Actual Number of non-CAP residential Bills ("ANBo")**								
12									Average ANBo
13	Monthly ANBo*		384,678	383,240	383,009	381,997	382,555	382,883	383,060
14									
15									
16	**Revenue to be Assigned to RNAo Rate**		$ (650,105.82)	$ (226,111.60)	$ 681,756.02	$ 1,065,771.63	$ (776,586.65)	$ (788,738.98)	$ (689,508.60)
17									
18	**Forecast Decatherms (Dth) for Effective RNA Period (FTo)***		3,466,867	1,490,983	761,618	413,474	378,169	464,334	6,975,444
19									
20	**RNAo Rate Effective April 2023 through September 2023**	ln 16 / ln 18							$ (0.0988)

* For illustrative purposes only.

K. MILLER

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

March 30, 2021

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I. Introduction

Q. Please state your name and business address.

A. Kelley K. Miller, 290 West Nationwide Boulevard, 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 primary responsibilities include providing support for base rate cases and other regulatory filings for several NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company").

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. 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 in Docket Nos. R-2014-2406274, R-2015-2468056, R-2016-2529660, R-2018-2647577 and R-2020-3018835, and for Columbia Gas of Virginia in Docket No. PUR-2018-00131.

<u>Statement of Purpose</u>

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 Ending December 31, 2022 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, and Exhibit 4. For the future test year and fully projected future test year, I am sponsoring Exhibit 101, Exhibit 102, Exhibit 104 (in coordination with Company witness Paloney (Columbia Statement No. 9)), and Exhibit 414. I am also sponsoring portions of Exhibits 13 and 113. 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 ended November 30, 2020 as the "historic test year" or "HTY", the twelve month period ending November 30, 2021 as the "future test year" or "FTY" and the twelve month period ending December 31, 2022 as the "fully projected future test year" or "FPFTY".

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, 2022 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 $98,278,240 based upon pro forma revenue requirement for the twelve months ending December 31, 2022. Columbia's computation of the revenue deficiency reflects total rate base of $2,673,012,065. 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 FPFTY, Exhibit 102 and Exhibit 104.

II. <u>HTY – Exhibit 2 – Statement of Income</u>

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, 2020. 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 12. Company witness Bell also provides the level of Gas Supply Expense and Off System Sales Expense that are included on lines 14 and 15, respectively. 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 O&M Expense level as presented on line 17. Lines 18 and 19, Depreciation and Amortization and Net Salvage Amortized, respectively, are provided by Company witness Spanos (Columbia Statement No. 5). Taxes Other Than Income, Income Taxes and Investment Tax Credit, lines 20, 23 and 24, respectively, have been provided by Company witness Harding (Columbia Statement No. 9), and Rate Base on line 26 has been provided by Company witness Shultz (Columbia Statement No. 6). The Percentage Rate of Return at Proposed Rates on Line 27, 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 the 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 on line 7.

Page 6 shows the calculated adjustments to pro forma expenses and income taxes to achieve the requested return on Rate Base of 7.88% shown on Exhibit 400 using the HTY data.

III. <u>HTY – Exhibit 4 - Operation & Maintenance Expenses</u>

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

A. In the HTY, Columbia recorded $183,197,648 in O&M expense exclusive of gas cost, as shown on Exhibit 4, Schedule 1, Page 2, Column 3. The O&M data is presented in a Cost Element format which provides a breakdown by cost causation. Note, for comparative purposes, Columbia has added per book actual O&M Expenses for two years prior to the HTY in Column 1 (twelve months ended November 30, 2018) and Column 2 (twelve months ended November 30, 2019).

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, Column 5.

Q. What adjustments has Columbia made to O&M expense?

A. The Company has reflected the following ratemaking adjustments to the HTY, each of which will be explained in greater detail later on in my testimony:

a) Labor related adjustments to annualize and normalize payroll for employees as of the end of the HTY;

b) An adjustment to incentive compensation;

c) An adjustment to annualize the amortization expense of the Prepaid Pension Deferral;

d) Removal of the negative OPEB expense;

e) Adjustments to normalize Outside Services;

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) Adjustment to remove non-recoverable employee expenses;

j) Company Memberships adjustments to latest known and measurable level less Lobbying Expense;

k) Removal of fuel used in company operations;

l) Advertising adjusted to remove non-recoverable items;

m) Adjustment to Materials and Supplies to remove Lobbying Expense;

n) Adjustment to Other O&M to remove non-recurring items;

o) Adjust Commission assessments (fees) to latest known and measurable level;

p) NCSC costs adjusted to annualize and normalize labor and incentive costs, and to remove non-recoverable and non-recurring items;

q) Adjust NCSC OPEB costs amortization level to reflect the annualized level;

r) Removal of Charitable Contributions;

s) Normalization of rate case expense;

t) Uncollectible expense explained and adjusted to a three year average experience;

u) Adjust USP Rider expense to match revenue; and

v) Included interest on customer deposits.

A. <u>Labor</u>

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

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 767 active Columbia employees as of November 2020. The difference, or annualization adjustment, was further adjusted to net O&M Expense by applying the O&M Expense experience percentage as provided on Exhibit No. 4, Schedule 2, Page 5. The annualization adjustment of $1,634,532 as calculated in Schedule 2, Page 1, Line 5, and a downward lobbying adjustment of $5,827 to remove labor relating to lobbying on Line 6, resulting in a total labor annualization and normalization adjustment of $1,628,705 is added to the actual HTY labor expense level of $36,383,823 in Schedule 1, Page 2. Total Pro Forma HTY labor expense level is $38,012,528 as shown on Exhibit 4, Schedule 1, Page 2.

B. <u>Incentive Compensation</u>

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

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

A. Columbia's HTY per books incentive level of $260,629 was increased by $1,640,296 to reflect the actual level of expense associated with incentive compensation paid in 2020. 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 O&M Expense experience percentage. Detail supporting the historic test year adjustment is provided on Exhibit 4, Schedule 2, Page 4.

C. <u>Prepaid Pension Deferral Amortization Expense</u>

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

Q. Please describe the ratemaking adjustment for Prepaid Pension Deferral Amortization Expense.

A. The Final Order approving the Settlement at Docket No. R-2018-2647577 permitted Columbia to recover the deferred prepaid pension O&M expense of $8,449,772 over a ten year period starting December 16, 2018. This ratemaking entry verifies the annual amount of $844,977 for amortization expense.

D. OPEB – Other Post Employment Benefits

Exhibit 4: *Schedule 1, Page 2, Line 5; Schedule 2, Page 7*

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 $665,789 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.

E. Outside Services

Exhibit 4: *Schedule 1, Page 2, Line 7; Schedule 2, Page 8 & 25*

Q. Please describe the ratemaking adjustment for Outside Services.

A. Ratemaking adjustments have been made to Outside Services to remove non-recoverable consulting costs associated with Lobbying and to remove non-recurring outside consultant and legal fees associated with Columbia's previous base rate case, Docket No. R-2020-3018835.

F. Rents and Leases

Exhibit 4: *Schedule 1, Page 2, Lines 8 & 9; 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 $2,475,857. This amount was then reconciled with the per book test year level of $2,406,373. The resulting adjustment is an increase of $95,067. 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 $473,846 and remains unchanged as seen on Exhibit 4, Schedule 1, Page 2, Line 9.

G. <u>Corporate Insurance</u>

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

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

A. Corporate insurance includes property insurance, workers compensation, medical stop loss premiums and other miscellaneous premiums. Most of Columbia's policy periods are either effective June 1 through May 31, July 1 through June 30, or November 1 through October 31 of each year. Premium payments are generally made the same month as the policy effective date. The prepayment of these costs are recorded and amortized over the appropriate fiscal period. The HTY adjustment annualizes expense to the latest annual premium payments by type of coverage from the amounts expensed during the period. Detailed calculations of these adjustments have been provided on Exhibit 4, Schedule 2, Page 10.

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

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

Q. Was an adjustment made for injury and damages?

A. Yes. The HTY expense level for injury and damages of $403,860 represents an amount including both actual experience and adjustments to an injury and damages accrual account. A downward adjustment of $45,689 was made to normalize the level of injuries and damages expense based upon a five year average actual cash outlay experience in real dollars using a Gross Domestic Product ("GDP") Deflator. As in previous base rate cases, a five 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>Employee Expenses</u>

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

Q. Was an adjustment made for employee expenses?

A. Yes. Downward adjustments of $81,759 and $5,827 were made to the HTY to remove certain employee expenses which Columbia is not seeking to include for recovery in this proceeding. Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 12.

J. Company Memberships

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

Q. Please explain the adjustments made for Company Memberships.

A. The HTY expense for Company Memberships has been adjusted for four primary items. Ratemaking adjustments in Column 2 totaling $13,547 were made to first remove expenses inadvertently recorded in the historic test year for Columbia related to another NiSource affiliate. Next, annualization adjustments were made for the American Gas Association dues reflective of the payments made relating to calendar year 2020. Column 2, Line 31 additionally contains the removal of an accrual item recorded in the HTY. Lastly, adjustments in Column 4, totaling a decrease of $42,842, were made to remove all costs identified as Lobbying from Company Memberships. The details of these adjustments are shown on Exhibit 4, Schedule 2, Page 13.

K. Utilities and Fuel Used in Company Operations

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

Q. What does the historic test year adjustment to Utilities and Fuel used in Company Operations represent?

A. A decrease to historic test year utilities and fuel used in company operations expense of $310,995 is 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 $2,207,819 represents other utility costs, such as electric and telecommunications (internet service, cell phones, land lines, etc.), not recovered through the 1307(f) process.

L. Advertising

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

Q. Was advertising adjusted?

A. Yes. Columbia has made an adjustment to remove the expenses associated with its advertising that do not represent a recoverable operating expense. The Company has removed $189,502 of brand advertising from HTY costs. Please see Exhibit 4, Schedule 2, page 15 for details.

M. Materials and Supplies

Exhibit 4: *Schedule 1, Page 2, Line 17; Schedule 2, Page 16*

Q. Was material and supplies adjusted?

A. Yes. Columbia has made an adjustment to remove lobbying-related materials and supply expenses $4,107. Please see Exhibit 4, Schedule 2, page 16 for details.

N. Other O&M

Exhibit 4: *Schedule 1, Page 2, Line 18; Schedule 2, Page 17*

Q. Was other O&M adjusted?

A. Yes. Columbia has made an adjustment to HTY Other O&M Expenses to remove non-recurring costs relating to NiSource Next totaling $2,239,070. Please see the testimony of Company witness Mark Kempic for further details for NiSource Next. Please see Exhibit 4, Schedule 2, page 17 for details.

O. Commission, OCA and OSBA Assessments

Exhibit 4: *Schedule 1, Page 2, Line 19; Schedule 2, Page 18*

Q. Please explain the $117,663 increase to the HTY Commission, OCA and OSBA Assessment expenses.

A. The adjustment is needed to increase the HTY level of 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 $2,008,792 reflects the most recent invoice amount (September 10, 2020) received as of the submission of this base rate filing.

P. NiSource Corporate Services Company ("NCSC")

Exhibit 4: *Schedule 1, page 2, Line 20; Schedule 2, pages 19-22*

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 such as 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 (See Ex. 4, Sch. 11, Att. B). NCSC currently updates the statistical data used in the approved allocation bases, at a 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. Have there been any changes to the billing methods used by NCSC since this Audit?

A. No, there have not.

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

A. Yes. The following adjustments have been made to NCSC charges for ratemaking purposes for the HTY and are summarized on Exhibit 4, Schedule 2, Page 19:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2020;

b) Annualization of Labor, Payroll Taxes & Benefits; and

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

Q. Please provide a brief overview of Exhibit 4, Schedule 2, Page 19.

A. Page 19, line 1 states the gross NCSC charges in the HTY. A portion of these costs are recorded to non-O&M accounts. Line 2 details the charges transferred to balance sheet or non-utility expenses. The HTY O&M costs generated from NCSC billings is $60,507,456.

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

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 19, Lines 4 through 15 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC Incentive Compensation to the level paid in 2020 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 20.

Line 5 - Annualizes NCSC labor, payroll taxes and benefits as detailed on Page 22. Net NCSC labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC labor charged to O&M and is derived on Exhibit 4 Schedule 2 Page 21 Line 15.

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

Lines 12 - 15 – Non-Recurring Items that were included in the HTY are removed in the pro forma HTY expense claim.

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

Exhibit 4: *Schedule 1, Page 2, Line 21; Schedule 2, Page 23*

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 23 shows that no adjustment is required as the HTY correctly reflects the annualized level of amortization expense of $90,313. Columbia anticipates that this Regulatory Asset will be fully amortized in June 2023.

R. <u>Charitable Contributions</u>

Exhibit 4: *Schedule 1, Page 2, Line 23; Schedule 2, Page 24*

Q. How are 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 24 for the details of removing any contributions that were inadvertently booked above the line during the HTY.

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

Exhibit 4: *Schedule 1, Page 2, Line 24; Schedule 2, Page 25*

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 base rate case include an amount for recovery of rate case expenses. Actual rate case expense incurred during the HTY for the Company's prior base rate case has been removed from the pro forma HTY expense and are detailed in lines 1 through 4. I have included a normalized level of rate case expense based on the proposed rate case expense normalization included in this current case as included on Exhibit 4, Schedule 2, and Page 25. The Company is using a one year normalization period due to prior base rate case filing experience and the expectation of future base rate case filings.

T. <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 26 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 29 for the HTY.

Q. Has the Company made any changes to these two major categories of expense since its last base rate case?

A. Yes. The Company has determined that charge offs for CAP customers who failed to pay the expected payment amount and were no longer eligible for CAP were not being included in normal uncollectible expense and were not picked up in the calculation for the three year average write-off rate used for determining uncollectible expense. Therefore, these uncollectible amounts were not included in the normalized level of uncollectible expense in the Company's prior base rate cases causing the Company to understate the actual level of uncollectible expense.

Q. Please define "CAP expected payment".

A. The "CAP expected payment" is the total billed amount a CAP customer must pay in order to remain a participant in the CAP Program. If a CAP customer fails to make the required expected payment, then they no longer qualify to participate in the CAP Program. Subsequent to default of a CAP customer's expected payment and termination of eligibility in the CAP Program, their total cumulative expected payment amount (Accounts Receivable balance) is written-off as normal uncollectible expense.

Q. Aren't these costs being recovered through Rider USP?

A. No. Rider USP recovers CAP Program costs which include program application and administration costs, CAP pre-program arrearages forgiveness, and the portion of arrearages quantified as the CAP Shortfall (the difference between the total bill, excluding Rider CC and Rider USP, and the customer's CAP expected payment). Rider USP costs do not include recovery of charge-offs (uncollectible expense) related to a customer's default on their CAP expected payment. If a CAP customer fails to make the required expected payment, they no longer qualify to be in the CAP program and their expected payment amount, which includes the remaining balance of preprogram arrearages not yet forgiven, is written off as normal uncollectible expense.

Q. Has the Company missed picking up these amounts when determining the adjustment to Uncollectible Account Expense on Exhibit 4, Schedule 2 in past base rate proceedings?

A. Yes. The Company uses a three year average of the ratio of net charge-offs as compared to billed revenues. The charge-off process for CAP customers who fail to make their expected payment is different that the process for non-CAP customers and utilizes slightly different accounting. The key identifiers utilized for ratemaking are expense Account and Cost Element. FERC Expense Account 904 is the account used for booking all uncollectible expense. Cost Element 3250 is utilized for non-CAP customers and is included in line 25 of Exhibit 4, Schedule 1, labeled as "Uncollectible Accounts" and Cost Element 3251 is utilized for CAP customers and is included in line 28 of Exhibit 4, Schedule 1, labeled as "Total USP Rider". Prior to the discovery of this issue, when these specific CAP customers failed to pay their expected payment and were no longer eligible to be classified as a CAP customer, their unpaid "expected pay" amount was written-off by inadvertently using Cost Element 3251, Total USP Rider. Consequently, these write-offs were not included in the three year average of net charge-offs as a percentage of billed revenues.

Q. In previous base rate cases, what happened to these expenses from a rate making perspective?

A. From a ratemaking perspective, these costs were totally eliminated from the Company's Cost of Service.

Q. Please explain.

A. The "Per Books" expense for these costs rolled to the line labeled as "Total USP Rider". For ratemaking purposes, this line is adjusted to match the Revenues for Rider USP so that the impact to the Cost of Service for base rates is zero, however, since the revenue for these expected payments are not included in Rider USP, the associated costs are simply eliminated. Also, as explained above, since they were not included in the process for determining the three year average experience for uncollectible expense, they were never included for recovery through either base rates or Rider USP.

Q. How is the Company proposing to fix this issue?

A. The Company has started to use Cost Element 3250 for writing-off these receivables and has updated the data that is used to determine the three-year average uncollectible expense ratio to now include the write-offs for these type of customers.

Q. **Please can you provide the impact of this change to Normalized Uncollectible Expense for the HTY?**

A. Yes. The three year average write-off rate is 0.0129153 and includes the write-offs of expected payments that were determined to be uncollectible. The rate without these write-offs would have been 0.0113537. When applying the difference in rates to FPFTY Annualized DIS Revenues adjusted of $583,380,065 (Exhibit 104, Schedule 2, Page 17, and Line 16) the result is $911,026.

Q. **What years are included in the calculation of the three year average write-off experience factor for determining normalized uncollectible expense for this proceeding?**

A. The Company is proposing to use data from the Twelve Months Ended November 30, 2017, 2018 and 2019 to determine an uncollectible experience factor to produce normalized uncollectible expense for this the HTY, FTY and FPFTY.

Q. **Why is the Company not using data from the Twelve Months Ended November 30, 2020 as a part of the three year average?**

A. The Company has determined that 2020 data is highly irregular and should not be used for determining normalized uncollectible expense. The irregular results are due to the COVID-19 Pandemic and the associated Emergency Order issued by the Pennsylvania Public Utility Commission "Commission" on March 13, 2020, at Docket No. M-2020-3019244, which prohibited regulated utilities from terminating service during the pendency of the Pandemic. The action of this Order, to prohibit terminations, and their subsequent write-off of customer accounts due to non-payment, has caused the level of net charge offs during the HTY to be extremely low compared to previous years, and is therefore not appropriate to use in a calculation for determining normal levels of uncollectible Expense.

Q. Has Columbia been deferring incremental Uncollectible Expense relating to COVID-19 as permitted by the Commission's March 13^{th} Order?

A. Yes. During the HTY, Columbia deferred $2,282,078 of incremental Uncollectible Expense to a Regulatory Asset.

Q. Has Columbia filed a notice as required by the Secretarial Letter?

A. Yes, Columbia file this notice on July 10, 2020.

Q. How has the Company determined incremental Uncollectible Expense?

A. The Company used data from R-2018-2647577, and attached as Exhibit KKM-1, to determine a baseline level of recovery for Uncollectible Expense as the FPFTY level of Uncollectible Expense per Ex. 104, Sch. 2, Page 21, $4,733,676, plus Uncollectible Expense Associated with the Settled Revenue Increase of $26 million, using the three year average write-off rate of 0.01191, or $309,539, for a total of $5,043,215 assumed to be recovered annually through base rates. Uncollectible amount in excess of this were deferred to a regulatory asset for future recovery.

Q. Is the Company proposing recovery of deferred Uncollectible Expense due to COVID-19 in this immediate proceeding?

A. Yes. I discuss this further in my testimony in section labeled as "Other Adjustments".

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

(Uncollectible Accounts & Uncollectible Accounts – Unbundled Gas)

Exhibit 4: *Schedule 1, Page 2, Line 25, 26 & 27; Schedule 2, Pages 26 – 28*

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

A. Exhibit 4, Schedule 2, Pages 26 sets 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, Columbia is using a three year average of data for the Twelve Months Ended November 30, 2017, 2018 and 2019 for this proceeding for reasons explained above. 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 27 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 (Columbia Statement No. 3) 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 26, titled as, "Total DIS Billed Revenue," has been adjusted to remove the revenue associated with Columbia's CAP (Page 28), as CAP uncollectibles are accounted for separately, as explained earlier in my testimony. Exhibit 4, Schedule 2, Line 4 of Page 26 represents Adjusted DIS Billed Revenue that relates to the net write-offs as shown on Exhibit 4, Schedule 2, Line 9 of Page 26.

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 26 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 and Column 4. Similarly, a three year total is developed for net write-offs. An uncollectible rate is then calculated by dividing the three year total net write-off by the three year total adjusted revenue. This rate, which is shown on Line 10, is then applied to the annualized DIS revenue as provided by Company 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. Yes. While DIS is one of three billing systems used to bill revenue related to normal uncollectible write-offs, the Company had no write-offs from the other billing systems.

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

A. The historic normal uncollectible adjustments are a total increase to expense of $1,213,673 as shown on Exhibit 4, Schedule 1, Page 2, Lines 25, 26 and 27. This amount has been developed by comparing an annualized DIS net write-off as described above and comparing that to the actual uncollectible expense level recorded in Columbia's historic test year ending November 30, 20. Note also that the COVID-19 Deferral amount on line 27 has been incorporated into this adjustment as a reduction to the "Per Books" Uncollectible Accounts Expense.

V. <u>Rider USP Costs</u>

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

Exhibit 4: *Schedule 1, Page 2, Line 28; Schedule 2, Page 29*

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 29.

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 $25,955,332 for the normalized HTY as determined by Company witness Bell. Consequently, the adjustment reflects changes that are necessary to match the expense with the revenues supported 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.

W. <u>Interest on Customer Deposits</u>

Exhibit 4: *Schedule 1, Page 2, Line 29; Schedule 2, Page 30*

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 projected future test year, because the Company has made no projection of changes to the balance of customer deposits.

IV. FTY/FPFTY – Exhibit 102 – Statement of Income

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 HTY, FTY, FPFTY at present rates and the FPFTY at Proposed Rates. Note that Columbia has included HTY information on Exhibit 102, Schedule 3, Page 3 for comparison purposes. 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 total revenue requirement. This Exhibit begins with the per books HTY in Column 2, followed by HTY adjustments at Present Rates in Column 3 to arrive at Pro Forma HTY in Column 4. Next, in Column 5, are the FTY adjustments at present rates to arrive at Pro Forma FTY in Column 6. Column 7 provides the FPFTY adjustment needed to arrive at Proforma FPFTY at Present Rates in Column 8. Adjustments in Column 9 are then made to determine the FPFTY at proposed rates in Column 10. Column 9 shows the revenue requirement of

$98,278,240 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 Column 1.

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

A. This page calculates the 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 FPFTY year rate base in Lines 5 through 8.

Q. Please explain Page 5 and 6 of Exhibit 102, Schedule 3.

A. Page 5 of Exhibit 102, Schedule 3 presents the calculation of the gross required revenue increase of $98,278,240 on Line 7 using the revenue conversion factor, applied to the Net Required Operating Income on Line 5. The revenue conversion factor calculation on Lines 8 through 17 accounts for additional normal uncollectible expense associated with the gross required revenue increase, as well as income taxes. The effective State Income Tax rate has been recalculated and reflects differences in the tax net operating loss positions. The Federal Income Tax rate is applies at 21% to arrive at Adjusted Operating Income as a percent of Total Operating Revenues. Page 6 determines the Net Required Operating Income by starting with Columbia's requested increase in revenues as calculated on Page 5 of Exhibit 102, Schedule 3. Line 2 displays the additional Late Payment Fee as 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 8, Line 11 by Total Sales and Transportation Revenues on Exhibit 102, Schedule 3, Page 3, Column 8, Line 9. 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. Next is the determination of the Uncollectible Expense, followed by the Income Tax calculations to determine the Net Required Operating Income on Line 12.

V. FTY/FPFTY – Exhibit 104 – Operations and Maintenance Expense

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

A. Yes. FTY and FPFTY levels of O&M expense begin with the budget as supplied and supported by Company witness Paloney (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 “Rate Making Adjustments” for both the FTY and the FPFTY. Company witness Paloney 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 FPFTY. 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 FPFTY.

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 FPFTY. 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 Paloney. 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 FPFTY, 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 FPFTY (Column 4) which is also supported by Company witness Paloney. Columns 5 and 6 provide Rate Making Adjustments and References followed by the Normalized FPFTY (Column 7).

Pages 5 and 6 provide the monthly Budget Data for FTY (Page 5) and FPFTY (Page 6); supported by Company witness Paloney.

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

A. No. Lines 1 through 21 on Exhibit No. 104, Schedule No. 1, Column 4, Pages 3 and 4 reflect the O&M budget data used in the FTY and FPFTY periods. The O&M budget data was not utilized for the cost items noted on Lines 23 through 28 of these same pages. These items include:

- Line 23 – 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 24– Uncollectible Accounts – the uncollectible expense is reflective of the standard practice of using a three year average of charge-off experience of FTY and FPFTY revenues as provided by Company witness Bell.
- Lines 25 & 26 – 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 27 – Interest on Customer Deposits – this item is not included in the O&M budget.
- Line 28 – Other Adjustments to the FPFTY O&M not in the budget.

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

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

a) Annualization of Company Labor;
b) Amortization of deferred non-recurring pension contribution;
c) Removal of the negative OPEB expense;
d) Outside Services adjustments;
e) Annualization of building rents and leases;
f) Injuries and Damages adjusted to reflect HTY plus inflation;
g) Removal of Employee Expenses;
h) Removal of fuel used in company operations;
i) Advertising adjusted to a normalized level of recoverable expense;
j) Removal of non-recurring expense for NiSource Next from Other O&M;
k) NCSC costs adjusted to annualize labor and remove non-recoverable items;
l) Removal of other lobbying expenses;
m) Normalization of rate case expense;
n) Adjust Uncollectible expense;
o) Adjust Rider USP expense to match revenue; and
p) Other Adjustments to the FPFTY.

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 $504,421 and for the FPFTY of $430,280. These adjustments are for normal pay increases and lobbying adjustments. Labor adjustments are charges prior to the timing of the annual budgeted increases, and reflect an O&M percentage of 52.64% and 52.01%, respectively, which is the same percentage as used in the Budget for items that have been adjusted from gross amounts to net O&M expense. The Lobbying adjustment is based upon the HTY adjustment, plus 3% to account for a wage increase.

B. <u>Prepaid Pension Deferral Amortization Adjustment</u>

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

Q. Please describe the ratemaking adjustment for Prepaid Pension Deferral Amortization.

A. The Final Order approving the Settlement of Columbia's base rate case at Docket No. R-2018-2647577 permits Columbia to recover the deferral of prepaid pension O&M expense of $8,449,772 over a ten year period starting December 16, 2018. This ratemaking entry adjusts the associated budgeted amortization expense to an annual amount of $844,977 for the FTY and FPFTY.

C. <u>OPEB – Other Post-Employment Benefits</u>

Exhibit 104: *Schedule 1, Page 2, Line 5; Schedule 2, Page 3*

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

A. Provision Nos. 30 and 31 of the settlement agreement of the Company's 2018 base rate case address this subject by stating:

> 30. 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.
>
> 31. 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 a credit to 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 3 comply with the provisions as listed above?

A. Yes, the FTY and FPFTY adjustments remove from the budgets the credit OPEB expense of $1,358,000 and $439,000, 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. <u>Outside Services</u>

Exhibit 104: *Schedule 1, Page 2, Line 7; Schedule 2, Page 4*

Q. Please explain the adjustment to outside services for the FTY and FPFTY.

A. The FTY includes a lobbying adjustment and an adjustment to remove non-recurring incremental expenses relating to COVID-19 (not relating to Uncollectible Expense). FPFTY only includes a lobbying adjustment.

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

Exhibit 104: *Schedule 1, Page 2, Line 8; Schedule 2, Pages 5 & 6*

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

A. Known changes to building leases attributable to contractual levels were included on Exhibit 104, Schedule 2, Page 5 and 6 resulting in an increase of $137,855 for the FTY claim and an increase of $77,457 for the FPFTY claim.

Q. Were there additional adjustments to rents and leases for the FTY and FPFTY besides the annualization adjustments?

A. Yes. The FPFTY includes the elimination of rents for Uniontown and Connellsville to reflect the construction of a new Company-owned facility for the Uniontown Operation Center.

F. Injuries and Damages

Exhibit 104: *Schedule 1, Page 2, Line 11; Schedule 2, Page 7*

Q. Was an adjustment made for injuries and damages?

A. Yes. The FTY and FPFTY expense levels for injury and damages were adjusted to reflect the pro forma HTY claim of $358,171 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, 2020.

G. Employee Expenses

Exhibit 104: *Schedule 1, Page 2, Line 12; Schedule 2, Page 8*

Q. Was an adjustment made for employee expenses?

A. Yes. The FTY and FPFTY expense levels for employee expenses were adjusted to remove non-recoverable employee expenses and lobbying by using the pro forma HTY adjustment of $87,586 plus applicable inflationary adjustments.

H. Utilities and Gas Used in Company Operations

Exhibit 104: *Schedule 1, Page 2, Line 14; Schedule 2, Page 9*

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

A. The FTY and FPFTY 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 FPFTY periods. The adjustments were calculated using the HTY adjustment level plus an inflationary adjustment.

I. <u>Advertising</u>

Exhibit 104: *Schedule 1, Page 2, Line 15; Schedule 2, Page 10*

Q. Please explain the adjustment for Advertising.

A. The FTY and FPFTY 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. Therefore, the pro forma level of HTY recoverable advertising was also used for FTY and FPFTY periods. This includes making significant reductions to the levels of advertising expense in the Budget for both periods.

J. <u>NiSource Next Adjustment</u>

Exhibit 104: *Schedule 1, Page 2, Line 18; Schedule 2, Pages 11*

Q. Are you sponsoring an adjustment to Other O&M for NiSource Next?

A. Yes, Exhibit 104, Schedule 2, Page 11 includes an adjustment to remove non-recurring consulting fees for NiSource Next, that have been included in Other O&M budget for the FTY.

Q. Is a similar adjustment needed for the FPFTY?

A. No, Other O&M for the FPFTY does not include any non-recurring costs.

K. <u>NiSource Corporate Services Company "NCSC"</u>

Exhibit 104: *Schedule 1, Page 2, Line 20; Schedule 2, Pages 12-14*

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

A. Yes. Exhibit 104, Schedule 2, Page 12 summarizes the ratemaking adjustments to NCSC for the FTY and FPFTY.

I have made adjustments to annualize labor and to remove non-recoverable items for both future periods, the FTY also includes an adjustment for a non-recurring item. Page 13 provides 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 a 3% increase of budgeted labor charges from December 2020 through February 2021, which annualizes labor for the months prior to the budgeted annual 3% merit increase to labor which occurred on March 1. In a similar fashion, the FPFTY has been adjusted to include a 3% increase of budgeted labor charges for January 2022 through February 2022.

Page 14 determines adjustments for the removal of non-recoverable and non-recurring items. The non-recoverable adjustments are based upon the HTY level of expense, plus incremental adjustments that are produced by using inflation factors. The non-recurring adjustment removes costs for the FTY only (the FPFTY does not include non-recurring costs).

Q. Please explain the non-recurring costs that are being adjusted out of the FTY budget for NCSC.

A. I have proposed rate making adjustments to remove from the FTY budget, non-recurring expenses relating to NiSource Next and Incremental COVID-19 (non-uncollectible expense) in order to normalize the level of FTY expenses for NCSC.

L. <u>Other Lobbying Expense</u>

Exhibit 104: *Schedule 1, Page 2, Lines 13 & 17; Schedule 2, Page 15*

Q. Please describe these lobbying expense adjustments.

A. Adjustments have been made for the removal of the remaining lobbying expenses in Company Memberships and Materials and Supplies. The FTY and FPFTY adjustments are based upon the HTY level of expense adjusted for inflation.

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

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

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

A. Yes. Exhibit 104, Schedule 2, Page 16 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 materials & supplies. The entire rate case expense included for normalization is $1,060,000. Columbia proposes to normalize these costs over twelve months.

N. Normal Uncollectible Accounts Expense

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 24 & 25; Schedule 2, Page 17*

Q. Please explain the FTY and FPFTY 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 26 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/FPFTY DIS revenues after adjusting for CAP revenue, to arrive at Total DIS Uncollectible Accounts Expense for the FTY and FPFTY.

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 $782,615 in the FPFTY 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.

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

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

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 $26,273,684 for the FTY and $26,432,574 for the FPFTY. 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. Company witness Bell computes the increase to Rider USP resulting from the proposed rate increase.

P. <u>Other Adjustments</u>

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

Q. Please explain the FPFTY other adjustments.

A. The Company has identified the following proposed O&M adjustments for the FPFTY that are not in the budget:

- Lines 1 through 10 – Amortization of Deferred COVID-19 Uncollectible Expense.
- Line 11 – Additional O&M Expense for Safety Management System (SMS) (supported by Company witness Curtis Anstead, Columbia Statement No. 14).

Q. Please describe the Company's proposal for recovering deferred Uncollectible Expense.

A. As explained earlier in my testimony, Columbia has been deferring incremental uncollectible expense as a result of the COVID-19 Pandemic, in accordance with the Secretarial Letter issued on May 13, 2020 at Docket No. M-2020-3019775. Columbia exceeded the baseline of annual recoveries for Uncollectible Expense in June of 2020 and made deferrals starting in June, through December 2020, totaling $5,579,245. Columbia is proposing to recover these deferrals over a 5 year period starting January 1, 2022, the beginning of the FPFTY. The resulting annual Amortization included in the FPFTY is $1,115,849.

Q. Is the Company planning on continuing to defer incremental Uncollectible Expense as the Pandemic and associated Emergency Orders continue to be in effect?

A. Yes. Currently, the Company plans to continue to defer incremental expense and plans to update the amount of amortization for this Regulatory Asset in a future base rate case proceeding, however, the Company is also evaluating when the appropriate time to cease this deferral is, based on the Commission's Order entered on March 18, 2020 in Docket M-2020-3019244.

Q. Is the Company planning on updating the deferral amounts to account for related recoveries or other true-up?

A. Yes. Columbia proposes that the Company be permitted to update this Regulatory Asset until the final impacts to customer accounts have been determined.

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 11/30/18, FPFTY = Fully Projected Future Test Year TME 12/31/19
Adjustment To Uncollectible Accounts Expense

Line No.	Description	Detail (1) $	Adjustment (2) $	Base Rate Uncoll (3) $	Unbundled Uncoll (4) $	
	FTY Adjustment					
1	**Normal Charge-Offs Recovered Through Base Rates (DIS Billed)**					
2	Total Annualized DIS Revenue	530,005,734				
3	Adjustments to Annualized Revenue:					
4	CAP Revenue Exh. 103, Sch. 1, Pg. 1, Ln. 24	29,093,389				
5	Annualized DIS Revenue adjusted (Ln 2 - Ln 4)	500,912,345				
6	Uncollectible Accounts Average Write-off Rate (Exh. 4, Sch. 2, Pg. 30)	0.0119054				
7	Total Annualized DIS Uncollectible Accounts	5,963,537	**5,963,537**			
8	Total Annualized GMB/GTS Revenue	38,876,217				
9	GMB/GTS 3 Year Average Write-off - Exh. 4, Sch. 2, Pg. 30, Ln. 22		**(66,153)**			
10	**Total FTY Annualized DIS & GMB/GTS Uncollectible Expense**		**5,897,384**	**4,688,161**	**1,209,223**	[1]
11	Total Per Budget			4,750,566	1,196,405	
12	Total FTY Adjustments for Uncollectible Expense			**(62,405)**	**12,818**	
	FPFTY Adjustment					
13	**Normal Charge-Offs Recovered Through Base Rates (DIS Billed)**					
14	Total Annualized DIS Revenue	534,561,779				
15	Adjustments to Annualized Revenue:					
16	CAP Revenue Exh. 103, Sch. 1, Pg. 11, Ln. 24	29,242,574				
17	Annualized DIS Revenue adjusted (Ln 14 - Ln 16)	505,319,205				
18	Uncollectible Accounts Average Write-off Rate (Exh. 4, Sch. 2, Pg. 30)	0.0119054				
19	Total Annualized DIS Uncollectible Accounts	6,016,003	**6,016,003**			
20	Total Annualized GMB/GTS Revenue	39,195,616				
21	GMB/GTS 3 Year Average Write-off - Exh. 4, Sch. 2, Pg. 30, Ln. 22		**(66,153)**			
22	**Total FPFTY Annualized DIS & GMB/GTS Uncollectible Expense**		**5,949,850**	**4,733,676**	**1,216,174**	[2]
23	Total Per Budget			4,688,161	1,209,223	
24	Total FPFTY Adjustments for Uncollectible Expense			**45,515**	**6,951**	

[1] Total Proposed Uncollectible Expense to be recovered in Exhibit 103, Page 11, Line 15, Col 5
[2] Total Proposed Uncollectible Expense to be recovered in Exhibit 103, Page 15, Line 15, Col 5

Assumed Recovery in Base Rate Only

FPFTY	4,733,676
Uncollectible Relating to Revenue Increase 1_/	309,539
	5,043,215

1_/ :

Revenue Increase	26,000,000
Uncollectible Accounts Average Write-off Rate (Exh. 4, Sch. 2, Pg. 30)	0.01191
Uncollectible Relating to Revenue Increase	309,539

COLUMBIA STATEMENT NO. 4-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

July 14, 2021

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I. Introduction

Q. Please state your name and business address.

A. Kelley K. Miller, 290 West Nationwide Boulevard, 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. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

The purpose of my testimony is to:

- Provide an updated revenue requirement deficiency of $96,234,266 which incorporates all adjustments provided by Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") rebuttal witnesses. This update is labeled as Exhibit KKM-1R, attached hereto;
- Provide a brief explanation of each item that contributed to the changes to the Company's revenue requirement that are supported below and by other witnesses;
- Respond to O&M ratemaking adjustments made by Mr. Zalesky, witness for the Bureau of Investigation and Enforcement ("I&E"), regarding rate case expense, Utilities and Fuel Used in Company Operation and COVID-19 Related Uncollectible Expense; and

- Respond to O&M ratemaking adjustment made by Mr. Effron, witness for Pennsylvania Office of Consumer Advocate ("OCA"), regarding rate case expense.

II. Exhibit KKM-1R, Updated Revenue Requirement

Q. Have you determined a revised revenue requirement?

A. Yes, Exhibit KKM-1R reflects an updated Exhibit 102, Schedule 3, Pages 3 through 6 and computes a revised revenue requirement of $96,234,266 as compared to the Company's originally stated revenue requirement of $98,278,240. This deficiency is noted on Page 3, Line 13 of Exhibit No. 102, reflected on page 1 of Exhibit KKM-1R.

Q. Can you provide a summary of items that the Company is adjusting that impact the revenue requirement?

A. Yes, below is a list of each adjustment:

1. Fully Projected Future Test Year ("FPFTY") Rate of Return Earned on Rate Base on Exhibit 102, Schedule 3, Page 3, Line 28, Column 10 (Exhibit KKM-1R, Page 1).

Per Company witness Moul, the overall rate of return has been updated to 7.89% to reflect actual long term debt costs for a recent issuance of debt. Please see witness Moul's rebuttal testimony for further details concerning this adjustment.

2. FPFTY Revenue Conversion Factor utilized on Exhibit 102, Schedule 3, Page 5, line 10 and Page 6, Lines 4&5.

The Revenue Conversion Factor has been updated to include the correct Uncollectible Accounts Expense Rate as determined on Exhibit 4, Schedule 2, Page

17. I discuss this further in my testimony below.

3. **Operating and Maintenance ("O&M") Expense Update for Correction for Fuel Used in Company Operations.**

   As explained below in my testimony, the Company provided updated ratemaking adjustments for all three test period to eliminate gas used in company operations from each test period. The FPFTY revenue requirement has been updated to reflect the correct adjustment. The adjustment differs from that contained in I&E witness Zalesky's Direct Testimony, as I explain later.

4. **Rate Base Update for Deferred Taxes.**

   Please see the testimonies of Company witnesses Shultz and Harding for details concerning this adjustment.

5. **Updated Safety Management System ("SMS") O&M Expenses as supported by Company witness Paloney.**

   Witness Paloney discusses updates to SMS Expense in the FPFTY, which reduces O&M expense by approximately $636,500.

6. **Updated Revenue for miscellaneous service revenue as supported by Company witness Bell.**

7. **Updated Amortization Expense per Witness Spanos.**

   Please see the rebuttal testimony of Company witness Spanos for detail concerning updated amortization expense.

Q. Is the Company proposing any additional changes impacting the revenue requirement and Exhibit 102?

A. Yes. All adjustments listed above, when worked through the Company's Cost of Service Model, result in updated amounts for Uncollectible Expense on Additional Revenue Requirement, Late Payment Fees, and Income Taxes, included in Exhibit KKM-1R, page 1.

Q. Does the Company agree with income tax adjustments that are derivative of other parties' other adjustments that have not been accepted by Columbia?

A. No. The Company does not agree. The income tax adjustments that are resulting from the adjustments identified above in my testimony have been derived using the same methodology as presented in the Company's original filing.

III. <u>Revenue Conversion Factor Uncollectible Expense Rate Update</u>

Q. What is the correct uncollectible expense rate per Exhibit 4, Schedule 2, page 17 that should have been utilized on Exhibit 102, Schedule 3, Pages 5 & 6?

A. As discussed in the response to part B of discovery request I&E-RE-066-D and attached to my rebuttal testimony as Exhibit KKM-2R, the correct uncollectible expense rate that should have been utilized on Exhibit 102, Schedule 3, Pages 5 and 6, as determined on Exhibit 4, Schedule 2, page 17, line 10 is 0.0129153.

Q. What rate was reflected in the original filing of Exhibit 102, Schedule 3, Pages 5 and 6?

A. The originally filed exhibit inadvertently included the rate of 0.0113537 on line 10 of page 5, which was also used to determine "Uncollectible Accounts Expense" relating to the revenue increase, on Page 6, Lines 4 and 5.

Q. What is the approximate impact to the Company's claim with this correction?

A. The approximate impact is an increase of $156,000 to the Company's claim.

IV. <u>I&E's Recommended Ratemaking Adjustments</u>

Q. Have you reviewed witness Zalesky's testimony regarding Rate Case Expense?

A. Yes.

Q. I&E recommends a 20-month normalization period for Rate Case Expenses versus the 12-month normalization period utilized by the Company. Do you agree? If not, please explain.

A. No, I do not agree. The Company utilized a 12-month period for normalizing Rate Case Expense because Columbia anticipates a need to file annual rate cases for the foreseeable future. In Columbia's last base rate case a one year normalization of rate case expense was proposed and in fact, this case was filed within 11 months, therefore, a 12-month normalization period is appropriate.

Q. Have you reviewed witness Zalesky's testimony regarding Utilities and Fuel Used in Company Operations?

A. Yes.

Q. Do you agree with his adjustment? If not please explain.

A. Witness Zalesky correctly references the Company's update regarding Fuel Used in Company Operations, provided as I&E Exhibit No. 1 Schedule No. 8, Pages 1 through 4, however he incorrectly applies both the Future Test Year ("FTY") and the FPFTY adjustments to the FPFTY.

Q. Please explain further.

A. Mr. Zalesky asserts that he includes both the FTY and FPFTY adjustments because "the FTY is the basis for the FPFTY". I&E Statement No. 1, Page 22. This statement is not accurate. Columbia's FPFTY claim is not a "build up" from its normalized FTY claim. Columbia utilizes unique budget amounts for each the FTY and the FPFTY. Each budget year includes an amount for Utilities and Fuel Used in Company Operations. However, because gas used in Company operations is recovered as Company Use Gas in Purchased Gas Cost rates, the budget must be adjusted. The updates in the referenced discovery response, provided as I&E-Exhibit No. 1, Schedule No.8, Page 4 of 4 determines adjustments for both test periods, however only the adjustment for the FPFTY is needed to update Columbia's claim. The adjustment for the FPFTY reduces Columbia's claim for O&M Expense by $60,055 only, versus the total of both the FTY and the FPFTY amounts ($58,964 + $60,055 = $119,019) as determined by witness Zalesky in his testimony on pages 21 and 22.

Q. Have you reviewed witness Zalesky's testimony regarding COVID-19 Deferrals?

A. Yes.

Q. Does Columbia agree with his position?

A. Yes, Columbia agrees with I&E's recommendation to end the incremental deferrals of COVID-19 uncollectible accounts expense as of the effective date of new rates at the conclusion of this base rate proceeding. The Company's claim in this case reflects an amortization of deferred COVID-19 uncollectible accounts expense through December 31, 2020. The continued deferrals from that date to the effective date of new rates will be reflected by the Company in its next base rate filing.

V. <u>OCA's Recommended Ratemaking Adjustments</u>

Q. Have you reviewed OCA witness Effron's testimony concerning Rate Case Expense?

A. Yes. Mr. Effron recommends an eighteen (18) month normalization period.

Q. Do you agree with this adjustment?

A. No, I do not agree. For the same reasons stated above in my rebuttal testimony regarding I&E's proposed adjustment for Rate Case Expense, it is appropriate to use a 12-month period.

VI. <u>I&E's Recommended Revenue Requirement</u>

Q. Did the Company find an error in I&E's work papers that impacted their recommended revenue increase?

A. Yes. Please refer to Columbia discovery request issued to I&E witness Zalesky, labeled as I&E-III-1 and attached as Exhibit KKM-3R, which identifies an issue with company interest for income taxes. The I&E work paper inadvertently included FTY company interest instead of FPFTY company interest in its income tax computation and subsequent recommended revenue increase computation.

Q. In their response, did I&E agree that the wrong company interest amount was used?

A. Yes.

Q. What is the corrected amount of I&E's recommended revenue increase provided by their response to this discovery request?

A. I&E's corrected recommended revenue increase is $56,263,748.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Exhibit No. 102
Schedule 3
Page 3 of 6
Witnes: K.K. Miller

Columbia Gas of Pennsylvania, Inc.
Statement of Income at Present and Proposed Rates
FTY = Future Test Year TME 11/30/21, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2022

Line No.	Description	Reference (1)	TME November 30, 2020 Per Books (2)	HTY Adjustments @ Present Rates (3)	Pro Forma Historic Test Year @ Present Rates (4)	FTY Adjustments @ Present Rates (5)	Pro Forma Future Test Year @ Present Rates (6)	FPFTY Adjustments @ Present Rates (7)	Pro Forma Fully Projected Future Test Year @ Present Rates (8)	Adjustments @ Proposed Rates (9)	FPFTY @ Proposed Rates (10)
			$	$	$	$	$	$	$	$	$
1	Operation Revenues										
2	Base Rate Revenues (Incl. Transportation)	Exhibit 3 / 103	394,768,736	67,898,584	462,667,320	5,329,910	467,997,230	2,934,754	470,931,984	96,050,521	566,982,505
3	Fuel Revenues	Exhibit 3 / 103	129,745,998	27,178,574	156,924,572	3,087,863	160,012,435	1,355,872	161,368,307	-	161,368,307
4	Rider USP	Exhibit 3 / 103	20,942,161	5,013,171	25,955,332	318,352	26,273,684	158,890	26,432,574		26,432,574
5	Gas Procurement Charge	Exhibit 3 / 103	2,252,252	(1,897,014)	355,238	(30,502)	324,736	45,483	370,219	-	370,219
6	Merchant Function Charge	Exhibit 3 / 103	812,793	(60,705)	752,088	17,697	769,785	12,830	782,615	-	782,615
7	Rider CC	Exhibit 3 / 103	40,729	5,098	45,827	915	46,742	249	46,991	-	46,991
8	Pipeline Penalty Refund	Exhibit 3	23,753	(23,753)	-	-	-	-	-	-	-
9	Total Sales and Transportation Revenue		548,586,422	98,113,955	646,700,377	8,724,235	655,424,612	4,508,078	659,932,690	96,050,521	755,983,211
10	Off System Sales Revenue	Exhibit 3 / 103	3,226,566	(3,226,566)	-	-	-	-	-	-	-
11	Late Payment Fees	Exhibit 3 / 103	502,806	734,332	1,237,138	16,689	1,253,827	8,624	1,262,451	183,745	1,446,195
12	Other Operating Revenues (Excl. Transportation)	Exhibit 3 / 103	11,584	(2)	11,582	-	11,582	59,635	71,217	-	71,217
13	Total Operating Revenues		552,327,378	95,621,718	647,949,096	8,740,924	656,690,020	4,576,337	661,266,358	**96,234,266**	757,500,624
							-				
14	Operating Revenue Deductions										
15	Gas Supply Expense	Exhibit 3 / 103	129,745,998	27,178,574	156,924,572	3,087,863	160,012,435	1,355,872	161,368,307	-	161,368,307
16	Off System Sales Expense	Exhibit 3 / 103	3,226,566	(3,226,566)	-	-	-	-	-	-	-
17	Gas Used in Company Operations		(369,008)	369,008	-	-	-	-	-	-	-
18	Operating and Maintenance Expense	Exhibit 4 / 104	183,197,647	7,137,219	190,334,865	27,188,399	217,523,264	6,492,704	224,015,969	1,242,894	225,258,863
19	Depreciation and Amortization	Exhibit 5 / 105	72,771,708	6,182,960	78,954,668	10,809,154	89,763,822	13,255,696	103,019,518	-	103,019,518
20	Net Salvage Amortized	Exhibit 5 / 105	5,667,409	(1,227,629)	4,439,780	289,514	4,729,294	430,406	5,159,700	-	5,159,700
21	Taxes Other Than Income Taxes	Exhibit 6 /106	3,362,482	255,896	3,618,378	65,292	3,683,670	32,268	3,715,938	-	3,715,938
22	Total Operating Revenue Deductions		397,602,802	36,669,461	434,272,263	41,440,222	475,712,485	21,566,946	497,279,431	1,242,894	498,522,325
23	Operating Income Before Income Taxes		154,724,576	58,952,258	213,676,833	(32,699,298)	180,977,535	(16,990,609)	163,986,926	94,991,372	258,978,298
24	Income Taxes	Exhibit 7 / 107	23,584,686	15,792,486	39,377,172	(8,909,719)	30,467,453	(6,679,448)	23,788,005	24,446,276	48,234,281
25	Investment Tax Credit	Exhibit 7 / 107	(287,111)	-	(287,111)	27,424	(259,687)	16,674	(243,013)	-	(243,013)
26	Operating Income		131,427,001	43,159,772	174,586,772	(23,817,003)	150,769,769	(10,327,835)	140,441,934	70,545,096	210,987,030
27	Rate Base	Exhibit 8 / 108	2,177,371,117	(88,057,950)	2,089,313,166	255,471,449	2,344,784,616	329,322,230	2,674,106,845	-	2,674,106,845
28	% Rate of Return Earned on Rate Base		6.04%		8.36%		6.43%		5.25%		7.89%

Exhibit No. 102
Schedule 3
Page 4 of 6
Witnes: K.K. Miller

Columbia Gas of Pennsylvania, Inc.
Calculation of Proforma Interest Expense
FTY = Future Test Year TME 11/30/21, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2022

Line No.	Description	Pro Forma (1) $
	FTY Calculation	
1	Rate Base	2,344,784,616
2	Weighted Cost of Short &	
3	Long Term Debt	1.940%
4	Interest Expense	45,488,822
	FPFTY Calculation	
5	Rate Base	2,674,106,845
6	Weighted Cost of Short &	
7	Long Term Debt	1.940%
8	Interest Expense	51,877,673

Columbia Gas of Pennsylvania, Inc.
Rate of Return on Rate Base
Proposed Revenue Requirement
FTY = Future Test Year TME 11/30/21, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2022

Line No.	Description	Detail	Amount
			(1)
			$
1	Proforma Rate Base at Present Rates		2,674,106,845
2	Return on Rate Base		7.890%
3	Total Requirement		210,987,030
4	Less: Net Operating Income at Present Rates		140,441,934
5	Net Required Operating Income		70,545,096
6	Revenue Conversion Factor		1.36415246
7	Gross Revenue Requirement		96,234,266
8	Revenue Conversion Factor:		
9	Operating Revenue		1.00000000
10	Less: Uncollectibles		**0.01291530**
11	Income Before State Taxes		0.98708470
12	State Income Tax Effect Tax Rate		0.05993999
13	Less: State Income Tax		0.05916585
14	Income Before Federal Taxes		0.92791885
15	Less: Federal Tax @ 21%		0.19486296
16	Adjusted Operating Income		0.73305589
17	Revenue Conversion Factor		1.36415246

Columbia Gas of Pennsylvania, Inc.
Additional Revenue Requirement Adjustments
FTY = Future Test Year TME 11/30/21, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2022

Line No.		Description	Amount
			(1)
			$
1		Additional Revenue Requirement	96,050,521
2	Plus:	Late Payments	183,745
3		Total Revenue Requirement	96,234,266
4	Less:	Uncollectible Accounts Expense	
5		Line 3 X Uncollectible Rate	1,242,894
6		Income Before State Income Tax	94,991,372
7		State Income Taxes	
8		Exh 107, Pg 17, Col 3 Less Exh 107, Pg 17, Col 2	5,693,782
9		Income Before Federal Income Tax	89,297,590
10		Federal Income Taxes	
11		Line 9 Times 21%	18,752,494
12		Net Required Operating Income	70,545,096

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-066-D:

Reference Columbia Exhibit No. 104, Schedule 2, p. 17 and Exhibit No. 102, Schedule 3, page 5 concerning uncollectibles. Provide the following:

A. Detailed narrative of each line and column of Exhibit No. 104, Schedule 2, page 17. Be sure to include the source and calculations of any amounts on this page; and

B. Explanation for the discrepancy between the Uncollectible Accounts Average Write-off Rate of 0.0129153 from lines 6 and 17 of Exhibit No. 104, Schedule 2, page 17 and the Less: Uncollectibles rate of 0.01135370 from line 10 of Exhibit No. 102, Schedule 3, page 5.

Response:

A. Please see Attachments A & B for a detailed narrative and source documents.

B. Exhibit 104, Schedule 2, Page 17 correctly reflects the Uncollectible factor of 0.0129153, as determined on Exhibit 4, Schedule 2, Page 26, reflecting a three year average write off-rate. Exhibit 102, Schedule 3, Page 5 is incorrect and should have also reflected the uncollectible rate of 0.0129153. When corrected, the Company's Gross Revenue Requirement increases by $155,482. As this correction impacts the Adjustment @ Proposed Rates for Revenue and for Uncollectible Expense on Exhibit 102, Schedule 3, Pages 3, 5 and 6, the Company will provide a corrected Exhibit 102, Schedule 3 as a part of its Rebuttal Testimony.

Pennsylvania Public Utility Commission v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2021-3024296

Response of the Bureau of Investigation and Enforcement to
Columbia Gas of Pennsylvania, Inc. Data Request Set III
Witness: John Zalesky

I&E-III-1 Please refer to I&E Direct tab of "2021 Columbia Gas Spreadsheet Workpapers Zalesky, cell reference B80." Was it I&E's intention to include Co. Interest for income taxes for the FTY instead of the Co. interest for income taxes for the FPFTY? If the answer is yes, please explain. If the answer is no, does I&E agree that the amount included should have been FPFTY co. interest of $51,589,133? What is the updated recommended Revenue Increase associated with updating to the FPFTY co. interest for income taxes?

Response: **No. I&E agrees that the amount included should have been $51,589,133. The updated I&E recommended revenue increase over I&E-adjusted present rate revenues of $661,266,358 is $56,263,748 for a total recommended revenue requirement of $717,530,106 as shown by attachment "2021 Columbia Gas Spreadsheet Workpapers Zalesky – Updated 2021-6-28".**

J. SPANOS

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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 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, January 2013 and February 2018.

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

A. I have over 34 years of depreciation experience which includes expert testimony in over 350 cases before approximately 41 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 700 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

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, 2020. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2021. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2022. 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 "2020 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2020," includes the results of the depreciation study as related to the original cost at November 30, 2020. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, titled "2021 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2021," includes the results of the depreciation study as related to the estimated original cost at November 30, 2021. 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 "2022 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2022," includes the results of the depreciation study as related to the estimated original cost at December 31, 2022.

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, 2021, and December 31, 2022.

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 including service life study filed in August 2017?

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, 394, 395 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 approximately 1 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-five 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, 2021, estimated?

A. The book reserve at November 30, 2021, 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, 2020. Annual accruals were estimated using the annual accruals calculated as of November 30, 2020. 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, 2021.

Q. Was the book reserve at December 31, 2022, 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 2016. 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 1939-2016. 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 Gas of Pennsylvania, Inc. and for other gas companies before the Pennsylvania Public Utility 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 Pennsylvania Public Utility 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 report and the service life study as conducted.

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 2016 through 2020.

Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost at November 30, 2021, 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 bringforward to November 30, 2021, of the book depreciation reserve as of November 30, 2020. 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, 2016 through 2020.

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-67 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, 2022. 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, 2022, are organized and presented in the same manner as those as of November 30, 2021.

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, 2020. 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, 2020, are organized and presented in the same manner as those as of November 30, 2021.

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 68 percent of the original cost of depreciable gas plant as of November 30, 2021.

The retirement rate method was used to analyze the survivor characteristics of this group. The life tables for the 1939-2016 and 1977-2016 experience bands are presented on pages VI-51 through VI-58 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 71-R1, on page VI-50.

The calculations of the annual depreciation related to the original cost at November 30, 2020, 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 71-R1 survivor curve, the attained age, and the allocated book reserve. The calculations at November 30, 2021, are presented by type main on pages VII-32 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, 2022 are presented by type main on pages II-32 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 2015 through 2019 for the calculation as of November 30, 2020, and on experience during the period 2016 through November 30, 2020, plus estimates for the last month of 2020 for the calculation as of November 30, 2021.

The amortization for the December 31, 2022 calculation is based on experience during the period 2016 through November 30, 2020, plus estimates for the period December 2020 through December 2021. 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-10 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, 2022, of the plant and book depreciation reserve as of November 30, 2021?

A. Yes, Exhibit JJS-01 at the end of this testimony provides the monthly detail of the plant in service, book depreciation reserve and the calculated depreciation. This exhibit agrees with the fully projected future test year plant and reserve balances 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

JOHN SPANOS DEPRECIATION EXPERIENCE

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 past 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 inAugust 2003, February 2008, January 2013 and February 2018.

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 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipeline Company Ltd., Interprovincial Pipeline Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: 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.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

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., in April 2012, I was promoted to the 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) and in January of 2019, I was promoted to my present position of President of 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; Iowa-American Water Company; New Jersey-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.; Aqua Illinois, 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; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; 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; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

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. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

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; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "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." I have also completed the

"Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.		Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.		IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	Pacificorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UE 388	Northwest Natural Gas Company	Depreciation

	2021	2021			2022		
	NOV 30	DECEMBER			JANUARY		
Account	Begin. Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	1,932.08			1,932.08			1,932.08
351.00	3,250,036.96			3,250,036.96			3,250,036.96
352.01	738,941.36			738,941.36			738,941.36
352.02	168,031.87			168,031.87			168,031.87
352.10	206,940.78			206,940.78			206,940.78
353.00	389,345.13			389,345.13			389,345.13
354.00	948,176.70			948,176.70			948,176.70
355.00	104,476.92			104,476.92			104,476.92
374.40	3,691,925.24	44,898.43	2,721.18	3,734,102.49	6,881.30	1,088.47	3,739,895.32
374.50	3,233,171.42			3,233,171.42			3,233,171.42
375.34	5,935,978.81	87,926.10	5,328.99	6,018,575.92	13,475.87	2,131.59	6,029,920.20
375.60	86,227.87			86,227.87			86,227.87
375.70	27,196,440.89	5,057,623.57	64,078.65	32,189,985.81		5,092.16	32,184,893.65
375.80	16,515.17			16,515.17			16,515.17
376.00	2,181,044,480.41	47,219,010.84	2,434,993.00	2,225,828,498.25	6,892,778.46	2,021,695.60	2,230,699,581.11
378.00	126,103,757.33	1,750,661.72	55,397.83	127,799,021.22	206,725.60	31,198.45	127,974,548.37
379.10	135,966.90			135,966.90			135,966.90
380.00	695,122,581.39	15,183,268.78	702,974.78	709,602,875.39	2,614,466.98	562,474.46	711,654,867.91
381.00	41,638,535.60	228,445.69	16,288.87	41,850,692.42	37,015.67	6,888.34	41,880,819.75
381.10	24,820,375.62	40,313.95		24,860,689.57	6,532.18		24,867,221.75
382.00	42,452,170.64	282,482.01	17,120.55	42,717,532.10	45,519.13	7,200.15	42,755,851.08
383.00	18,993,073.78	192,974.61	11,695.72	19,174,352.67	26,701.25	4,223.57	19,196,830.35
385.00	7,811,445.82	205,784.48	12,472.10	8,004,758.20	31,539.27	4,988.84	8,031,308.63
387.00	136,698.14			136,698.14			136,698.14
387.40	11,443,998.08			11,443,998.08			11,443,998.08
387.50	2,201,371.95			2,201,371.95			2,201,371.95
390.10	49,821.42			49,821.42			49,821.42
391.10	2,285,833.24		168,329.10	2,117,504.14			2,117,504.14
391.11	91,303.67			91,303.67			91,303.67
391.12	2,692,531.12		747,863.29	1,944,667.83			1,944,667.83
392.00	25,616.89			25,616.89			25,616.89
394.00	18,382,788.16	280,428.13	2,741,889.36	15,921,326.93	60,067.97		15,981,394.90
394.12				0.00			0.00
395.00	266,039.42			266,039.42			266,039.42
396.00	948,698.04			948,698.04			948,698.04
397.50	1,677,225.06	234,033.08	14,184.17	1,897,073.97	33,116.24	5,238.28	1,924,951.93
398.00	953,269.70		8,228.13	945,041.57			945,041.57
303.00	32,302,002.60	2,010,695.67	461,200.23	33,851,498.04		55,010.40	33,796,487.64
303.60	9,051,102.42	3,664,304.33		12,715,406.75			12,715,406.75
375.71	5,607,225.91	192,958.91	61,565.77	5,738,619.05		4,892.46	5,733,726.59
Total Plant	**3,272,206,054.51**	**76,675,810.30**	**7,526,331.72**	**3,341,355,533.09**	**9,974,819.92**	**2,712,122.77**	**3,348,618,230.24**

	2022			2022		
	FEBRUARY			MARCH		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	9,341.86	1,088.47	3,748,148.71	9,706.35	1,360.59	3,756,494.47
374.50			3,233,171.42			3,233,171.42
375.34	18,294.48	2,131.59	6,046,083.09	19,008.26	2,664.49	6,062,426.86
375.60			86,227.87			86,227.87
375.70		5,092.16	32,179,801.49		5,092.16	32,174,709.33
375.80			16,515.17			16,515.17
376.00	9,357,448.81	2,396,512.32	2,237,660,517.60	9,722,544.03	2,359,422.89	2,245,023,638.74
378.00	280,645.05	31,198.45	128,223,994.97	291,594.85	33,704.21	128,481,885.61
379.10			135,966.90			135,966.90
380.00	3,549,329.36	650,684.81	714,553,512.46	3,687,811.89	811,927.68	717,429,396.67
381.00	50,251.47	6,888.34	41,924,182.88	52,212.11	8,610.42	41,967,784.57
381.10	8,867.91		24,876,089.66	9,213.90		24,885,303.56
382.00	61,795.53	7,200.15	42,810,446.46	64,206.58	9,000.19	42,865,652.85
383.00	36,248.88	4,223.57	19,228,855.66	37,663.19	5,279.46	19,261,239.39
385.00	42,816.86	4,988.84	8,069,136.65	44,487.42	6,236.05	8,107,388.02
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	81,546.66		16,062,941.56	84,728.32		16,147,669.88
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	44,957.70	5,238.28	1,964,671.35	46,711.80	6,547.85	2,004,835.30
398.00			945,041.57			945,041.57
303.00		41,003.43	33,755,484.21		72,705.03	33,682,779.18
303.60			12,715,406.75			12,715,406.75
375.71		4,892.46	5,728,834.13		4,892.46	5,723,941.67
Total Plant	**13,541,544.57**	**3,161,142.87**	**3,358,998,631.94**	**14,069,888.70**	**3,327,443.48**	**3,369,741,077.16**

	2022			2022		
	APRIL			MAY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	15,560.10	1,904.83	3,770,149.74	14,367.41	2,721.18	3,781,795.97
374.50			3,233,171.42			3,233,171.42
375.34	30,471.87	3,730.29	6,089,168.44	28,136.17	5,328.99	6,111,975.62
375.60			86,227.87			86,227.87
375.70		5,092.16	32,169,617.17		5,092.16	32,164,525.01
375.80			16,515.17			16,515.17
376.00	15,586,064.99	2,074,846.67	2,258,534,857.06	14,391,379.72	2,351,977.19	2,270,574,259.59
378.00	467,451.35	81,617.88	128,867,719.08	431,620.80	89,135.15	129,210,204.73
379.10			135,966.90			135,966.90
380.00	5,911,876.12	708,539.49	722,632,733.30	5,458,725.74	811,927.68	727,279,531.36
381.00	83,700.44	12,054.59	42,039,430.42	77,284.73	17,220.85	42,099,494.30
381.10	14,770.67		24,900,074.23	13,638.49		24,913,712.72
382.00	102,928.61	12,600.27	42,955,981.19	95,039.04	18,000.39	43,033,019.84
383.00	60,377.31	7,391.24	19,314,225.46	55,749.33	10,558.91	19,359,415.88
385.00	71,317.13	8,730.47	8,169,974.68	65,850.61	12,472.10	8,223,353.19
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	135,826.71		16,283,496.59	125,415.47		16,408,912.06
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	74,882.98	9,166.99	2,070,551.29	69,143.14	13,095.70	2,126,598.73
398.00			945,041.57			945,041.57
303.00		93,231.22	33,589,547.96		390,039.51	33,199,508.45
303.60			12,715,406.75			12,715,406.75
375.71		4,892.46	5,719,049.21		4,892.46	5,714,156.75
Total Plant	**22,555,228.28**	**3,023,798.56**	**3,389,272,506.88**	**20,826,350.65**	**3,732,462.27**	**3,406,366,395.26**

	2022			2022		
	JUNE			JULY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	17,209.98	2,721.18	3,796,284.77	16,752.41	2,721.18	3,810,316.00
374.50			3,233,171.42			3,233,171.42
375.34	33,702.87	5,328.99	6,140,349.50	32,806.81	5,328.99	6,167,827.32
375.60			86,227.87			86,227.87
375.70	212,797.06	5,092.16	32,372,229.91		5,092.16	32,367,137.75
375.80			16,515.17			16,515.17
376.00	17,238,694.69	2,613,018.70	2,285,199,935.58	16,780,368.19	2,676,375.58	2,299,303,928.19
378.00	517,016.39	89,135.15	129,638,085.97	503,270.43	98,229.28	130,043,127.12
379.10			135,966.90			135,966.90
380.00	6,538,727.22	988,348.39	732,829,910.19	6,364,881.58	988,348.39	738,206,443.38
381.00	92,575.43	17,220.85	42,174,848.88	90,114.11	17,220.85	42,247,742.14
381.10	16,336.83		24,930,049.55	15,902.49		24,945,952.04
382.00	113,842.39	18,000.39	43,128,861.84	110,815.65	18,000.39	43,221,677.10
383.00	66,779.25	10,558.91	19,415,636.22	65,003.79	10,558.91	19,470,081.10
385.00	78,879.06	12,472.10	8,289,760.15	76,781.89	12,472.10	8,354,069.94
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	150,228.76		16,559,140.82	146,234.61		16,705,375.43
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	82,823.01	13,095.70	2,196,326.04	80,620.99	13,095.70	2,263,851.33
398.00			945,041.57			945,041.57
303.00	4,010,480.67	1,831,442.30	35,378,546.82			35,378,546.82
303.60	3,026,519.33		15,741,926.08			15,741,926.08
375.71	204,452.08	4,892.46	5,913,716.37		4,892.46	5,908,823.91
Total Plant	**32,401,065.02**	**5,611,327.28**	**3,433,156,133.00**	**24,283,552.95**	**3,852,335.99**	**3,453,587,349.96**

	2022			2022		
	AUGUST			SEPTEMBER		
Account	**Additions**	**Retirements**	**Ending Balance**	**Additions**	**Retirements**	**Ending Balance**
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	19,245.79	2,721.18	3,826,840.61	21,768.94	2,721.18	3,845,888.37
374.50			3,233,171.42			3,233,171.42
375.34	37,689.66	5,328.99	6,200,187.99	42,630.85	5,328.99	6,237,489.85
375.60			86,227.87			86,227.87
375.70		5,092.16	32,362,045.59	212,797.06	5,092.16	32,569,750.49
375.80			16,515.17			16,515.17
376.00	19,277,901.79	2,472,118.06	2,316,109,711.92	21,805,268.82	2,485,746.67	2,335,429,234.07
378.00	578,175.51	98,229.28	130,523,073.35	653,975.35	98,229.28	131,078,819.42
379.10			135,966.90			135,966.90
380.00	7,312,209.15	1,106,914.41	744,411,738.12	8,270,852.72	915,315.87	751,767,274.97
381.00	103,526.38	17,220.85	42,334,047.67	117,098.88	17,220.85	42,433,925.70
381.10	18,269.37		24,964,221.41	20,664.51		24,984,885.92
382.00	127,309.08	18,000.39	43,330,985.79	143,999.52	18,000.39	43,456,984.92
383.00	74,678.74	10,558.91	19,534,200.93	84,469.25	10,558.91	19,608,111.27
385.00	88,209.86	12,472.10	8,429,807.70	99,774.33	12,472.10	8,517,109.93
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	167,999.68		16,873,375.11	190,024.74		17,063,399.85
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	92,620.35	13,095.70	2,343,375.98	104,763.04	13,095.70	2,435,043.32
398.00			945,041.57			945,041.57
303.00		1,077,849.96	34,300,696.86	4,010,480.67	127,354.98	38,183,822.55
303.60			15,741,926.08	3,026,519.33		18,768,445.41
375.71		4,892.46	5,903,931.45	204,452.08	4,892.46	6,103,491.07
Total Plant	**27,897,835.36**	**4,844,494.45**	**3,476,640,690.87**	**39,009,540.09**	**3,716,029.54**	**3,511,934,201.42**

	2022			2022		
	OCTOBER			NOVEMBER		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	42,878.64	2,721.18	3,886,045.83	21,388.80	2,721.18	3,904,713.45
374.50			3,233,171.42			3,233,171.42
375.34	83,970.67	5,328.99	6,316,131.53	41,886.40	5,328.99	6,352,688.94
375.60			86,227.87			86,227.87
375.70		5,092.16	32,564,658.33		5,092.16	32,559,566.17
375.80			16,515.17			16,515.17
376.00	42,950,189.74	2,484,603.61	2,375,894,820.20	21,424,489.15	1,787,994.94	2,395,531,314.41
378.00	1,288,145.78	55,604.02	132,311,361.18	642,555.15	55,604.02	132,898,312.31
379.10			135,966.90			135,966.90
380.00	16,291,232.02	1,049,059.73	767,009,447.26	8,126,420.99	976,027.22	774,159,841.03
381.00	230,651.57	17,220.85	42,647,356.42	115,054.01	17,220.85	42,745,189.58
381.10	40,703.21		25,025,589.13	20,303.65		25,045,892.78
382.00	283,638.19	18,000.39	43,722,622.72	141,484.90	18,000.39	43,846,107.23
383.00	166,380.45	10,558.91	19,763,932.81	82,994.18	10,558.91	19,836,368.08
385.00	196,527.10	12,472.10	8,701,164.93	98,031.99	12,472.10	8,786,724.82
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	374,294.79		17,437,694.64	186,706.38		17,624,401.02
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	206,353.45	13,095.70	2,628,301.07	102,933.59	13,095.70	2,718,138.96
398.00			945,041.57			945,041.57
303.00		15,375.98	38,168,446.57		252,323.23	37,916,123.34
303.60			18,768,445.41			18,768,445.41
375.71		4,892.46	6,098,598.61		4,892.46	6,093,706.15
Total Plant	**62,154,965.61**	**3,694,026.08**	**3,570,395,140.95**	**31,004,249.19**	**3,161,332.15**	**3,598,238,057.99**

	2022		
	DECEMBER		
Account	Additions	Retirements	Ending Balance
350.20			1,932.08
351.00			3,250,036.96
352.01			738,941.36
352.02			168,031.87
352.10			206,940.78
353.00			389,345.13
354.00			948,176.70
355.00			104,476.92
374.40	44,898.43	2,721.18	3,946,890.70
374.50			3,233,171.42
375.34	87,926.10	5,328.99	6,435,286.05
375.60			86,227.87
375.70	212,797.06	5,092.16	32,767,271.07
375.80			16,515.17
376.00	44,973,353.38	1,532,941.10	2,438,971,726.69
378.00	1,348,823.74	55,604.02	134,191,532.03
379.10			135,966.90
380.00	17,058,628.59	769,250.88	790,449,218.74
381.00	241,516.38	17,220.84	42,969,485.12
381.10	42,620.53		25,088,513.31
382.00	296,998.93	18,000.34	44,125,105.82
383.00	174,217.78	10,558.95	20,000,026.91
385.00	205,784.48	12,472.10	8,980,037.20
387.00			136,698.14
387.40			11,443,998.08
387.50			2,201,371.95
390.10			49,821.42
391.10		94,356.55	2,023,147.59
391.11			91,303.67
391.12		1,577,540.60	367,127.23
392.00			25,616.89
394.00	391,925.90	303,527.92	17,712,799.00
394.12			0.00
395.00		1,118.18	264,921.24
396.00			948,698.04
397.50	216,073.71	13,095.70	2,921,116.97
398.00		136.82	944,904.75
303.00	4,010,480.67	459,807.81	41,466,796.20
303.60	3,026,519.33		21,794,964.74
375.71	204,452.08	4,892.46	6,293,265.77
Total Plant	**72,537,017.09**	**4,883,666.60**	**3,665,891,408.48**

RESERVE BRINGFORWARD

lumber of months for accrual calculation = 12 **mber of months in FFTY =** 13

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2021							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	DECEMBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,337,386
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,884
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	823,271
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,167	769	5,936	2,721	218	0	0	848,597
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,795,044
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	10,958	2,752	13,710	5,329	1,972	0	0	1,450,670
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,498
375.70	3,781,479	2.98	0.00		1	0.00		1	73,738	0	73,738	64,079	0	0	0	3,791,139
375.80	8,259	2.17							30	0	30	0	0	0	0	8,289
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,057,996	104,954	4,162,950	2,434,993	219,149	0	0	293,873,938
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	403,071	16,939	420,010	55,398	14,403	0	0	20,931,749
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	56,236
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,773,466	259,908	2,033,374	702,975	231,982	0	0	139,505,967
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,141	(5,076)	78,065	16,289	0	1,792	0	17,909,540
381.10	17,041,116	5.62							116,336	0	116,336	0	0	0	0	17,157,452
382.00	15,035,037	1.88			2			2	66,716	0	66,716	17,121	0	0	0	15,084,633
383.00	7,831,229	2.04			185			653	32,442	15	32,458	11,696	0	0	0	7,851,991
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	34,532	9,551	44,083	12,472	4,490	0	0	2,449,624
387.00	78,374	3.02							344	0	344	0	0	0	0	78,718
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	187	45,581	0	0	0	0	2,854,226
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,568,717
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,917	0	6,917	168,329	0	0	0	976,331
391.11	47,228	6.39							486	0	486	0	0	0	0	47,714
391.12	2,174,689	14.57							28,152	0	28,152	747,863	0	0	0	1,454,977
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,931
394.00	7,626,712	3.49			(437)			(923)	49,884	(36)	49,847	2,741,889	0	0	54	4,934,724
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	84,376
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,935)	(1,536)	0	0	0	0	894,482
397.50	659,240	4.37	0.00		51	0.00		51	6,508	4	6,512	14,184	0	0	0	651,568
398.00	478,581	6.08							4,809	0	4,809	8,228	0	0	0	475,162
303.00	17,029,312								558,100	0	558,100	461,200	0	0	0	17,126,212
303.60	1,291,101								273,111	0	273,111	0	0	0	0	1,564,212
362.10	(151,290)				67,200			61,646	0	5,600	5,600	0	0	0	0	(145,690)
375.71	2,501,391								190,151	0	190,151	61,566	0	0	0	2,629,977
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,869,972**	**394,105**	**8,264,077**	**7,526,332**	**472,214**	**1,792**	**0**	**562,828,667**

RESERVE BRINGFORWARD

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

	2021	Accrual	PROJECTED 21			PROJECTED 2022			2022							
	NOV 30	Rates	COR	Salvage	5-yr Amort of NS	COR	Salvage	5-yr Amort of NS	JANUARY							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,359,599
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,911
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	826,282
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,201	805	6,005	1,088	87	0	0	853,427
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,797,954
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,044	2,631	13,676	2,132	789	0	0	1,461,426
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,551
375.70	3,781,479	2.98	0.00		1	0.00		1	79,932	0	79,932	5,092	0	0	0	3,865,979
375.80	8,259	2.17							30	0	30	0	0	0	0	8,319
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,103,720	129,307	4,233,026	2,021,696	181,953	0	0	295,903,316
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	406,041	22,144	428,184	31,198	8,112	0	0	21,320,623
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	58,258
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,794,338	262,967	2,057,305	562,474	185,617	0	0	140,815,181
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,383	(1,797)	81,586	6,888	0	758	0	17,984,995
381.10	17,041,116	5.62							116,446	0	116,446	0	0	0	0	17,273,899
382.00	15,035,037	1.88			2			2	66,954	0	66,954	7,200	0	0	0	15,144,387
383.00	7,831,229	2.04			185			653	32,616	54	32,670	4,224	0	0	0	7,880,437
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,012	9,230	44,242	4,989	1,796	0	0	2,487,081
387.00	78,374	3.02							344	0	344	0	0	0	0	79,062
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	2,899,777
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,586,071
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	982,983
391.11	47,228	6.39							486	0	486	0	0	0	0	48,200
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,478,589
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,727
394.00	7,626,712	3.49			(437)			(923)	46,392	(77)	46,315	0	0	0	54	4,981,093
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	85,531
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	893,821
397.50	659,240	4.37	0.00		51	0.00		51	6,959	4	6,964	5,238	0	0	0	653,294
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	479,950
303.00	17,029,312								558,100	0	558,100	55,010	0	0	0	17,629,301
303.60	1,291,101								273,111	0	273,111	0	0	0	0	1,837,324
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(140,553)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	2,815,236
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,939,227**	**429,975**	**8,369,202**	**2,712,123**	**378,353**	**758**	**0**	**568,108,152**

RESERVE BRINGFORWARD

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

PROJECTED 21 PROJECTED 2022

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2016-2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 FEBRUARY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,381,813
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,939
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	829,292
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,210	805	6,015	1,088	87	0	0	858,266
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,800,864
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,070	2,631	13,701	2,132	789	0	0	1,472,206
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,603
375.70	3,781,479	2.98	0.00		1	0.00		1	79,919	0	79,920	5,092	0	0	0	3,940,806
375.80	8,259	2.17							30	0	30	0	0	0	0	8,349
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,114,615	129,307	4,243,922	2,396,512	215,686	0	0	297,535,040
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	406,715	22,144	428,859	31,198	8,112	0	0	21,710,172
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	60,280
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,800,588	262,967	2,063,555	650,685	214,726	0	0	142,013,326
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,456	(1,797)	81,659	6,888	0	758	0	18,060,523
381.10	17,041,116	5.62							116,482	0	116,482	0	0	0	0	17,390,381
382.00	15,035,037	1.88			2			2	67,027	0	67,027	7,200	0	0	0	15,204,214
383.00	7,831,229	2.04			185			653	32,662	54	32,716	4,224	0	0	0	7,908,930
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,153	9,230	44,383	4,989	1,796	0	0	2,524,679
387.00	78,374	3.02							344	0	344	0	0	0	0	79,406
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	2,945,328
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,603,425
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	989,636
391.11	47,228	6.39							486	0	486	0	0	0	0	48,687
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,502,200
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,523
394.00	7,626,712	3.49			(437)			(923)	46,598	(77)	46,521	0	0	0	54	5,027,668
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	86,686
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	893,159
397.50	659,240	4.37	0.00		51	0.00		51	7,082	4	7,087	5,238	0	0	0	655,142
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	484,738
303.00	17,029,312								558,100	0	558,100	41,003	0	0	0	18,146,397
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,110,435
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(135,416)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,000,494
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,957,768**	**429,975**	**8,387,743**	**3,161,143**	**441,195**	**758**	**0**	**572,894,314**

RESERVE BRINGFORWARD

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

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	MARCH							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,404,027
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,966
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	832,303
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,222	805	6,027	1,361	109	0	0	862,823
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,803,773
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,099	2,631	13,731	2,664	986	0	0	1,482,286
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,656
375.70	3,781,479	2.98	0.00		1	0.00		1	79,907	0	79,907	5,092	0	0	0	4,015,621
375.80	8,259	2.17							30	0	30	0	0	0	0	8,378
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,127,805	129,307	4,257,112	2,359,423	212,348	0	0	299,220,380
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	407,521	22,144	429,664	33,704	8,763	0	0	22,097,369
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	62,302
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,807,878	262,967	2,070,846	811,928	267,936	0	0	143,004,308
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,542	(1,797)	81,746	8,610	0	947	0	18,134,606
381.10	17,041,116	5.62							116,525	0	116,525	0	0	0	0	17,506,906
382.00	15,035,037	1.88			2			2	67,113	0	67,113	9,000	0	0	0	15,262,327
383.00	7,831,229	2.04			185			653	32,717	54	32,771	5,279	0	0	0	7,936,422
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,319	9,230	44,549	6,236	2,245	0	0	2,560,747
387.00	78,374	3.02							344	0	344	0	0	0	0	79,750
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	2,990,879
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,620,780
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	996,288
391.11	47,228	6.39							486	0	486	0	0	0	0	49,173
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,525,812
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,319
394.00	7,626,712	3.49			(437)			(923)	46,840	(77)	46,763	0	0	0	54	5,074,485
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	87,841
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	892,498
397.50	659,240	4.37	0.00		51	0.00		51	7,228	4	7,232	6,548	0	0	0	655,826
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	489,527
303.00	17,029,312								558,100	0	558,100	72,705	0	0	0	18,631,792
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,383,547
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(130,279)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,185,753
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,979,905**	**429,975**	**8,409,880**	**3,327,443**	**492,387**	**947**	**0**	**577,485,310**

RESERVE BRINGFORWARD

ʲumber of months for accrual calculation = 12 ʲmber of months in FFTY = 13

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	PROJECTED 21 COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2016-2020	PROJECTED 2022 COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 APRIL Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,426,241
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,993
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	835,313
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,237	805	6,042	1,905	152	0	0	866,808
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,806,683
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,139	2,631	13,770	3,730	1,380	0	0	1,490,946
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,708
375.70	3,781,479	2.98	0.00		1	0.00		1	79,894	0	79,894	5,092	0	0	0	4,090,423
375.80	8,259	2.17							30	0	30	0	0	0	0	8,408
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,147,027	129,307	4,276,333	2,074,847	186,736	0	0	301,235,131
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	408,542	22,144	430,686	81,618	21,221	0	0	22,425,217
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	64,324
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,818,078	262,967	2,081,046	708,539	233,818	0	0	144,142,996
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,657	(1,797)	81,860	12,055	0	1,326	0	18,205,738
381.10	17,041,116	5.62							116,581	0	116,581	0	0	0	0	17,623,486
382.00	15,035,037	1.88			2			2	67,227	0	67,227	12,600	0	0	0	15,316,954
383.00	7,831,229	2.04			185			653	32,789	54	32,844	7,391	0	0	0	7,961,874
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,539	9,230	44,769	8,730	3,143	0	0	2,593,643
387.00	78,374	3.02							344	0	344	0	0	0	0	80,094
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,036,430
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,638,134
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,002,941
391.11	47,228	6.39							486	0	486	0	0	0	0	49,659
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,549,423
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,115
394.00	7,626,712	3.49			(437)			(923)	47,160	(77)	47,083	0	0	0	54	5,121,622
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	88,996
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	891,836
397.50	659,240	4.37	0.00		51	0.00		51	7,421	4	7,425	9,167	0	0	0	654,084
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	494,315
303.00	17,029,312								558,100	0	558,100	93,231	0	0	0	19,096,661
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,656,658
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(125,141)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,371,012
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,011,482**	**429,975**	**8,441,457**	**3,023,799**	**446,450**	**1,326**	**0**	**582,457,845**

RESERVE BRINGFORWARD

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

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	PROJECTED 21 COR % of Rets	PROJECTED 21 Salvage % of Rets	5-yr Amort of NS 2016-2020	PROJECTED 2022 COR % of Rets	PROJECTED 2022 Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 MAY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,448,454
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,020
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	838,324
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,255	805	6,059	2,721	218	0	0	869,929
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,809,593
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,184	2,631	13,815	5,329	1,972	0	0	1,497,461
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,761
375.70	3,781,479	2.98	0.00		1	0.00		1	79,882	0	79,882	5,092	0	0	0	4,165,212
375.80	8,259	2.17							30	0	30	0	0	0	0	8,438
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,170,555	129,307	4,299,861	2,351,977	211,678	0	0	302,971,337
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	409,699	22,144	431,842	89,135	23,175	0	0	22,744,749
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	66,347
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,830,514	262,967	2,093,482	811,928	267,936	0	0	145,156,614
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,788	(1,797)	81,992	17,221	0	1,894	0	18,272,402
381.10	17,041,116	5.62							116,647	0	116,647	0	0	0	0	17,740,134
382.00	15,035,037	1.88			2			2	67,358	0	67,358	18,000	0	0	0	15,366,312
383.00	7,831,229	2.04			185			653	32,873	54	32,927	10,559	0	0	0	7,984,242
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,792	9,230	45,022	12,472	4,490	0	0	2,621,703
387.00	78,374	3.02							344	0	344	0	0	0	0	80,438
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,081,981
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,655,488
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,009,593
391.11	47,228	6.39							486	0	486	0	0	0	0	50,145
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,573,035
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,911
394.00	7,626,712	3.49			(437)			(923)	47,540	(77)	47,463	0	0	0	54	5,169,139
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	90,151
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	891,175
397.50	659,240	4.37	0.00		51	0.00		51	7,642	4	7,647	13,096	0	0	0	648,634
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	499,103
303.00	17,029,312								558,100	0	558,100	390,040	0	0	0	19,264,721
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,929,769
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(120,004)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,556,271
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,049,920**	**429,975**	**8,479,895**	**3,732,462**	**509,469**	**1,894**	**0**	**586,697,702**

RESERVE BRINGFORWARD

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

PROJECTED 21 PROJECTED 2022

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2016-2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 JUNE Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,470,668
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,048
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	841,334
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,273	805	6,078	2,721	218	0	0	873,067
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,812,503
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,231	2,631	13,862	5,329	1,972	0	0	1,504,023
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,813
375.70	3,781,479	2.98	0.00		1	0.00		1	80,133	0	80,133	5,092	0	0	0	4,240,254
375.80	8,259	2.17							30	0	30	0	0	0	0	8,468
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,195,109	129,307	4,324,415	2,613,019	235,172	0	0	304,447,562
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	410,922	22,144	433,065	89,135	23,175	0	0	23,065,503
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	68,369
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,843,388	262,967	2,106,356	988,348	326,155	0	0	145,948,466
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,923	(1,797)	82,126	17,221	0	1,894	0	18,339,202
381.10	17,041,116	5.62							116,717	0	116,717	0	0	0	0	17,856,851
382.00	15,035,037	1.88			2			2	67,493	0	67,494	18,000	0	0	0	15,415,805
383.00	7,831,229	2.04			185			653	32,959	54	33,013	10,559	0	0	0	8,006,696
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	36,054	9,230	45,284	12,472	4,490	0	0	2,650,025
387.00	78,374	3.02							344	0	344	0	0	0	0	80,782
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,127,532
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,672,842
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,016,246
391.11	47,228	6.39							486	0	486	0	0	0	0	50,631
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,596,646
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,707
394.00	7,626,712	3.49			(437)			(923)	47,941	(77)	47,864	0	0	0	54	5,217,057
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	91,306
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	890,513
397.50	659,240	4.37	0.00		51	0.00		51	7,871	4	7,876	13,096	0	0	0	643,414
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	503,891
303.00	17,029,312								558,100	0	558,100	1,831,442	0	0	0	17,991,378
303.60	1,291,101								273,111	0	273,111	0	0	0	0	3,202,881
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(114,867)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,741,530
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,090,205**	**429,975**	**8,520,180**	**5,611,327**	**591,181**	**1,894**	**0**	**589,017,269**

RESERVE BRINGFORWARD

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

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	JULY							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,492,882
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,075
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	844,345
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,293	805	6,098	2,721	218	0	0	876,226
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,815,413
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,282	2,631	13,914	5,329	1,972	0	0	1,510,636
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,867
375.70	3,781,479	2.98	0.00		1	0.00		1	80,385	0	80,385	5,092	0	0	0	4,315,546
375.80	8,259	2.17							30	0	30	0	0	0	0	8,498
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,221,564	129,307	4,350,871	2,676,376	240,874	0	0	305,881,183
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	412,244	22,144	434,388	98,229	25,540	0	0	23,376,122
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	70,391
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,857,183	262,967	2,120,151	988,348	326,155	0	0	146,754,113
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,071	(1,797)	82,274	17,221	0	1,894	0	18,406,150
381.10	17,041,116	5.62							116,793	0	116,793	0	0	0	0	17,973,644
382.00	15,035,037	1.88			2			2	67,641	0	67,641	18,000	0	0	0	15,465,446
383.00	7,831,229	2.04			185			653	33,053	54	33,107	10,559	0	0	0	8,029,245
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	36,339	9,230	45,569	12,472	4,490	0	0	2,678,633
387.00	78,374	3.02							344	0	344	0	0	0	0	81,126
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,173,083
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,690,196
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,022,898
391.11	47,228	6.39							486	0	486	0	0	0	0	51,118
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,620,258
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,503
394.00	7,626,712	3.49			(437)			(923)	48,372	(77)	48,295	0	0	0	54	5,265,407
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	92,461
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	889,852
397.50	659,240	4.37	0.00		51	0.00		51	8,121	4	8,125	13,096	0	0	0	638,443
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	508,679
303.00	17,029,312								558,100	0	558,100	0	0	0	0	18,549,478
303.60	1,291,101								273,111	0	273,111	0	0	0	0	3,475,992
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(109,730)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,926,789
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,133,532**	**429,975**	**8,563,507**	**3,852,336**	**599,248**	**1,894**	**0**	**593,131,087**

RESERVE BRINGFORWARD

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

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	AUGUST							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,515,096
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,102
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	847,355
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,314	805	6,119	2,721	218	0	0	879,406
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,818,323
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,337	2,631	13,968	5,329	1,972	0	0	1,517,304
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,919
375.70	3,781,479	2.98	0.00		1	0.00		1	80,372	0	80,372	5,092	0	0	0	4,390,826
375.80	8,259	2.17							30	0	30	0	0	0	0	8,528
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,250,027	129,307	4,379,333	2,472,118	222,491	0	0	307,565,908
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	413,649	22,144	435,792	98,229	25,540	0	0	23,688,146
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	72,413
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,871,805	262,967	2,134,773	1,106,914	365,282	0	0	147,416,690
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,229	(1,797)	82,433	17,221	0	1,894	0	18,473,257
381.10	17,041,116	5.62							116,873	0	116,873	0	0	0	0	18,090,517
382.00	15,035,037	1.88			2			2	67,800	0	67,800	18,000	0	0	0	15,515,245
383.00	7,831,229	2.04			185			653	33,154	54	33,208	10,559	0	0	0	8,051,894
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	36,645	9,230	45,875	12,472	4,490	0	0	2,707,546
387.00	78,374	3.02							344	0	344	0	0	0	0	81,470
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,218,634
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,707,550
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,029,551
391.11	47,228	6.39							486	0	486	0	0	0	0	51,604
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,643,869
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,299
394.00	7,626,712	3.49			(437)			(923)	48,829	(77)	48,752	0	0	0	54	5,314,213
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	93,616
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	889,190
397.50	659,240	4.37	0.00		51	0.00		51	8,389	4	8,393	13,096	0	0	0	633,741
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	513,468
303.00	17,029,312								558,100	0	558,100	1,077,850	0	0	0	18,029,728
303.60	1,291,101								273,111	0	273,111	0	0	0	0	3,749,103
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(104,593)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,112,048
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,179,613**	**429,975**	**8,609,588**	**4,844,494**	**619,991**	**1,894**	**0**	**596,278,085**

RESERVE BRINGFORWARD

ɩumber of months for accrual calculation = 12 ɱber of months in FFTY = 13

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	SEPTEMBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,537,309
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,129
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	850,366
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,339	805	6,144	2,721	218	0	0	882,611
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,821,233
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,401	2,631	14,032	5,329	1,972	0	0	1,524,036
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,972
375.70	3,781,479	2.98	0.00		1	0.00		1	80,624	0	80,624	5,092	0	0	0	4,466,358
375.80	8,259	2.17							30	0	30	0	0	0	0	8,558
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,283,292	129,307	4,412,599	2,485,747	223,717	0	0	309,269,042
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	415,293	22,144	437,437	98,229	25,540	0	0	24,001,813
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	74,435
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,888,926	262,967	2,151,893	915,316	302,054	0	0	148,351,213
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,415	(1,797)	82,618	17,221	0	1,894	0	18,540,548
381.10	17,041,116	5.62							116,964	0	116,964	0	0	0	0	18,207,481
382.00	15,035,037	1.88			2			2	67,984	0	67,984	18,000	0	0	0	15,565,229
383.00	7,831,229	2.04			185			653	33,271	54	33,325	10,559	0	0	0	8,074,660
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	37,001	9,230	46,231	12,472	4,490	0	0	2,736,814
387.00	78,374	3.02							344	0	344	0	0	0	0	81,814
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,264,185
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,724,904
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,036,203
391.11	47,228	6.39							486	0	486	0	0	0	0	52,090
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,667,481
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,095
394.00	7,626,712	3.49			(437)			(923)	49,350	(77)	49,273	0	0	0	54	5,363,540
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	94,772
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	888,529
397.50	659,240	4.37	0.00		51	0.00		51	8,701	4	8,705	13,096	0	0	0	629,350
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	518,256
303.00	17,029,312								558,100	0	558,100	127,355	0	0	0	18,460,473
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,022,215
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(99,456)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,297,307
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,233,750**	**429,975**	**8,663,725**	**3,716,030**	**557,990**	**1,894**	**0**	**600,669,684**

RESERVE BRINGFORWARD

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

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	OCTOBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,559,522
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,157
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	853,376
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,380	805	6,185	2,721	218	0	0	885,856
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,824,142
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,507	2,631	14,139	5,329	1,972	0	0	1,530,873
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	76,024
375.70	3,781,479	2.98	0.00		1	0.00		1	80,875	0	80,875	5,092	0	0	0	4,542,141
375.80	8,259	2.17							30	0	30	0	0	0	0	8,588
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,338,344	129,307	4,467,651	2,484,604	223,614	0	0	311,028,475
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	418,132	22,144	440,275	55,604	14,457	0	0	24,372,028
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	76,457
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,917,456	262,967	2,180,423	1,049,060	346,190	0	0	149,136,387
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,727	(1,797)	82,930	17,221	0	1,894	0	18,608,151
381.10	17,041,116	5.62							117,108	0	117,108	0	0	0	0	18,324,589
382.00	15,035,037	1.88			2			2	68,291	0	68,291	18,000	0	0	0	15,615,519
383.00	7,831,229	2.04			185			653	33,466	54	33,521	10,559	0	0	0	8,097,622
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	37,593	9,230	46,823	12,472	4,490	0	0	2,766,676
387.00	78,374	3.02							344	0	344	0	0	0	0	82,158
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,309,736
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,742,259
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,042,856
391.11	47,228	6.39							486	0	486	0	0	0	0	52,576
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,691,092
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	20,891
394.00	7,626,712	3.49			(437)			(923)	50,170	(77)	50,093	0	0	0	54	5,413,687
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	95,927
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	887,867
397.50	659,240	4.37	0.00		51	0.00		51	9,220	4	9,224	13,096	0	0	0	625,478
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	523,044
303.00	17,029,312								558,100	0	558,100	15,376	0	0	0	19,003,196
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,295,326
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(94,318)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,482,566
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,323,459**	**429,975**	**8,753,434**	**3,694,026**	**590,940**	**1,894**	**0**	**605,140,046**

RESERVE BRINGFORWARD

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

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	PROJECTED 21 COR % of Rets	PROJECTED 21 Salvage % of Rets	5-yr Amort of NS 2016-2020	PROJECTED 2022 COR % of Rets	PROJECTED 2022 Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 NOVEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,581,736
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,184
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	856,387
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,421	805	6,226	2,721	218	0	0	889,143
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,827,052
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,613	2,631	14,244	5,329	1,972	0	0	1,537,817
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	76,077
375.70	3,781,479	2.98	0.00		1	0.00		1	80,863	0	80,863	5,092	0	0	0	4,617,911
375.80	8,259	2.17							30	0	30	0	0	0	0	8,617
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,393,688	129,307	4,522,995	1,787,995	160,920	0	0	313,602,556
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	421,020	22,144	443,164	55,604	14,457	0	0	24,745,131
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	78,479
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,945,726	262,967	2,208,694	976,027	322,089	0	0	150,046,964
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	85,037	(1,797)	83,240	17,221	0	1,894	0	18,676,065
381.10	17,041,116	5.62							117,251	0	117,251	0	0	0	0	18,441,840
382.00	15,035,037	1.88			2			2	68,596	0	68,596	18,000	0	0	0	15,666,115
383.00	7,831,229	2.04			185			653	33,660	54	33,715	10,559	0	0	0	8,120,778
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	38,182	9,230	47,412	12,472	4,490	0	0	2,797,126
387.00	78,374	3.02							344	0	344	0	0	0	0	82,502
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,355,287
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,759,613
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,049,508
391.11	47,228	6.39							486	0	486	0	0	0	0	53,062
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,714,704
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	20,687
394.00	7,626,712	3.49			(437)			(923)	50,986	(77)	50,909	0	0	0	54	5,464,650
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	97,082
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	887,206
397.50	659,240	4.37	0.00		51	0.00		51	9,735	4	9,739	13,096	0	0	0	622,122
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	527,832
303.00	17,029,312								558,100	0	558,100	252,323	0	0	0	19,308,973
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,568,438
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(89,181)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,667,825
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,412,968**	**429,975**	**8,842,943**	**3,161,332**	**504,145**	**1,894**	**0**	**610,319,406**

RESERVE BRINGFORWARD

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

	2021	Accrual	PROJECTED 21		5-yr	PROJECTED 2022		5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	DECEMBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,603,950
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,211
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	859,397
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,463	805	6,268	2,721	218	0	0	892,472
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,829,962
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,722	2,631	14,353	5,329	1,972	0	0	1,544,869
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	76,129
375.70	3,781,479	2.98	0.00		1	0.00		1	81,114	0	81,114	5,092	0	0	0	4,693,933
375.80	8,259	2.17							30	0	30	0	0	0	0	8,647
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,451,772	129,307	4,581,078	1,532,941	137,965	0	0	316,512,728
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	424,005	22,144	446,149	55,604	14,457	0	0	25,121,218
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	80,501
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,975,319	262,967	2,238,286	769,251	253,853	0	0	151,262,147
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	85,358	(1,797)	83,561	17,221	0	1,894	0	18,744,299
381.10	17,041,116	5.62							117,398	0	117,398	0	0	0	0	18,559,238
382.00	15,035,037	1.88			2			2	68,911	0	68,911	18,000	0	0	0	15,717,025
383.00	7,831,229	2.04			185			653	33,861	54	33,915	10,559	0	0	0	8,144,134
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	38,791	9,230	48,021	12,472	4,490	0	0	2,828,185
387.00	78,374	3.02							344	0	344	0	0	0	0	82,846
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,400,839
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,776,967
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,504	0	6,504	94,357	0	0	0	961,656
391.11	47,228	6.39							486	0	486	0	0	0	0	53,548
391.12	2,174,689	14.57							14,035	0	14,035	1,577,541	0	0	0	151,198
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	20,483
394.00	7,626,712	3.49			(437)			(923)	51,386	(77)	51,309	303,528	0	0	54	5,212,486
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,153	0	1,153	1,118	0	0	0	97,116
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	886,544
397.50	659,240	4.37	0.00		51	0.00		51	10,268	4	10,272	13,096	0	0	0	619,299
398.00	478,581	6.08							4,788	0	4,788	137	0	0	0	532,483
303.00	17,029,312								558,100	0	558,100	459,808	0	0	0	19,407,265
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,841,549
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(84,044)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,853,084
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,496,830**	**429,975**	**8,926,805**	**4,883,667**	**412,954**	**1,894**	**0**	**613,951,483**

COLUMBIA STATEMENT NO. 5-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

JULY 14, 2021

Q. Please state your name and address.

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

Q. Are you the same John J. Spanos who submitted Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to portions of the testimony filed by the Office of Consumer Advocate witness David J. Effron regarding his recommended adjustments to plant in service and depreciation expense calculated as of December 31, 2022. I will also address his issue with the amortization amounts for Account 303 and 375.71.

Q. Do you agree with Mr. Effron's recommendations?

A. No. I have a number of concerns regarding Mr. Effron's recommendations and how he has calculated his recommended adjustments. First, it is unreasonable to suggest one "average" amount adjustment to plant in service when calculating depreciation. Depreciation rates are calculated at an individual plant account level due to the different life characteristics of the assets within each plant account. Merely recommending a $87,471,000 reduction to plant in service without defining the recommended adjustments by individual plant account is an oversimplification of the determination of rate base. Second, Mr. Effron uses the terms "additions" and "net plant additions" interchangeably throughout his testimony. There are significant differences in the impact to depreciation between what Mr. Effron references as "additions" and/or "net plant additions". Third, once Mr. Effron recommends a reduction of $87,471,000 to plant in service as of December 31, 2022, he utilizes the composite depreciation rate of 2.50%, which was calculated as of December 31, 2022 including the $87,471,000 plant in service amount, to calculate his recommended reduction to depreciation expense of $2,187,000. This fails to recognize that the composite depreciation rate changes as the amount and composition of plant changes.

Q. Are you specifically addressing Mr. Effron's proposed reduction to plant in service?

A. No, not specifically as Company witness, Nicole Shultz, and others will address Mr. Effron's reductions to plant in service. I have only addressed the unreasonable assumptions Mr. Effron makes with regard to forecasted data. My rebuttal focuses on the issues of depreciation expense and process in developing test year depreciation rates and expense.

Q. Can you comment on Mr. Effron's reasoning for reducing the forecasted plant in service?

A. Yes. Mr. Effron suggests that the forecasted additions in 2021 and 2022 should be reduced because the amounts are higher than the previous two years. However, he does not compare what the Company forecasted in prior years to what was actually spent in order to see the forecasts were very close to actuals. He also makes the leap that what was spent in 2019 and 2020 should be the same as what is forecasted in 2021 and 2022. This is not reasonable as each asset will have a recovery pattern consistent with its useful life and that is based on age and expected remaining life. Consequently, using net additions is not realistic and averaging net additions levels of prior years under different conditions improperly reduce rate base in his calculations.

Q. Why is it unreasonable to suggest one "average" amount to plant in service when calculating depreciation?

A. As mentioned earlier, depreciation rates are calculated and vary by plant account which means the value and age of the assets have different recovery impacts to each account. This is clear when focusing on the service lives experienced by the assets in each plant account. For these reasons, it is unreasonable to even suggest an adjustment to plant in service and/or depreciation without defining the amount of the adjustment by individual plant account.

Q. What is the difference between "Additions" and "Net Plant Additions"?

A. "Additions" represent plant in service added during a specified time frame. "Net Plant Additions", as used by Mr. Effron, consist of multiple types of plant activity such as additions, retirements and transfers. The issue that Mr. Effron ignores when he calculates his recommended adjustment to depreciation expense is the impact of retirement activity on the accumulated depreciation. When a retirement is made, plant in service and accumulated depreciation are both reduced by the amount of the retirement. Hence, merely calculating a depreciation expense adjustment by multiplying an undefined plant in service amount by a composite rate (which Mr. Effron is suggesting) is also inappropriate.

Q. Why is the adjustment to depreciation expense proposed by Mr. Effron not calculated correctly?

A. First, Mr. Effron is recommending reductions to both plant in service and depreciation expense as of December 31, 2022. However, Mr. Effron utilizes the 2.50% composite depreciation rate calculated utilizing the plant in service amount he is proposing to be changed to calculate his adjustment to depreciation expense. If

Mr. Effron believes the Company's plant in service as of December 31, 2022 to be incorrect, then he could not possibly believe the composite depreciation rate calculated using an incorrect plant in service amount to be a viable option to calculate his adjustment to depreciation expense. Therefore, Mr. Effron's calculated adjustment to depreciation expense is not appropriate.

Second, since Mr. Effron did not adjust his projected accumulated depreciation appropriately and did not reflect a change on an account level of the retirements to the accumulated depreciation, the impact of his changes is not accurate. Mr. Effron's oversimplification of the depreciation calculations do not follow the standard practices supported by the Commission in properly calculating depreciation rates for each test year.

Q. Can you address Mr. Effron's adjustments regarding Amortizable Plant in Account 303 and 375.71?

A. Yes. First, it is important to reiterate that the assets in Account 303, Miscellaneous Intangible Plant and Account 375.71, Structures and Improvements – Leased, are individually amortized, therefore, a rate by account is not established. Second, the annual expense of each of these asset classes is based on the period of time each individual asset will be amortized. As is standard for amortized assets, they stay on the books for the duration of the amortization period, then no longer have amortization expense to be recorded. Therefore, the annual expense for each account is not a forecast to continue but an amount recorded for the test year. Thus, it is critical to segregate additions from retirements and not focus on net additions as Mr. Effron has done.

Q. Please explain why net plant and 5-year averages as proposed by Mr. Effron are not realistic for Account 303.

A. First, I will address why Mr. Effron's net plant impact for Account 303 is misrepresenting the annual expense presented by the assets in the future test year. The assets in Account 303 are individually amortized over 3 to 10 years. In the future test year November 2020 through November 2021 there is a net plant decrease of approximately $300,000, however, it is critical to understand that there is $4.2 million added and $4.5 million retired. The majority of the $4.2 million in additions has a 3-to-5-year amortization period so the total annual expense for these assets would range between $800,000 and $1,400,000. The retired assets of $4.5 million primarily had an amortization period of 5 to 7 years and many of the assets were retired early in 2021, therefore, a small amount of annual expense is recorded for the retired assets for the test year. A similar situation occurs for the fully projected future test year. In the fully projected future test year, there is approximately $14 million added and $4.9 million retired which is set forth in Exhibit JJS-01 as stated in my direct testimony. Again, the new additions in most cases have an amortization period of 5 years so a substantial increase in annual expense for the summation of all assets in Account 303 should be expected. The increase in annual expense should approximate $2,800,000. This account has many assets with an individual amortization period so you cannot treat the entire account together like a group depreciation which is why there is no account rate presented in the depreciation study. Mr. Effron's adjustment to reduce amortization by approximately $2.1 million is not appropriate.

Q. Mr. Effron calculates a five year amortization of the fully projected future test year net plant additions for Account 303 to derive an amortization amount of $1.785 Million, which he adds to the historic test year amortization of $4.138 Million, to derive an amortization amount of $5.923 Million. Why is this approach incorrect?

A. As discussed earlier in this testimony, the assets in Account 303 are individually amortized and annual expense is not consistent from year to year. Additionally, using net plant does not reflect the actual individual applications that are retired and the new assets added with unique amortization periods. The assets in Account 303 are not subject to group depreciation and average life characteristics so it is not reasonable to merely add five year averages to the current levels of expense.

Q. Can you address the amortization expense adjustment for Account 375.71 that Mr. Effron discusses on pages 30 and 31 of his testimony?

A. Yes. Account 375.71 is handled in a very similar manner as Account 303. Assets are individually amortized with different amortization periods. Therefore, Mr. Effron's five year average approach is not appropriate for determining the annual expense for Account 375.71. However, there is a correction in the annual expense calculation for the future test year and fully projected future test year. Upon review, it was discovered that a plant addition recorded to another 375 Account was inadvertently included in the calculation of the amortization of Account 375.71. The correct amortization amounts should be $488,178 for the future test year and $564,482 for the fully projected future test year. The corrected schedules for each test year are attached to this testimony as Exhibit JJS-1R. Again, it is important to understand that assets in Account 375.71 are individually amortized and are not the same as depreciable assets. Mr. Effron's adjustment to reduce amortization by approximately $2 million is not appropriate, however, the revised amounts will reduce the annual expense by approximately $1,791,000 for the fully projected future test year.

Q. Does this complete your prepared rebuttal testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF NOVEMBER 30, 2021

	DEPRECIABLE GROUP (1)	SURVIVOR CURVE (2)		ORIGINAL COST AS OF NOVEMBER 30, 2021 (3)	BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	CALCULATED ANNUAL ACCRUAL AMOUNT (6)	CALCULATED ANNUAL ACCRUAL RATE (7)=(6)/(3)	COMPOSITE REMAINING LIFE (8)=(5)/(6)
DEPRECIABLE PLANT									
UNDERGROUND STORAGE PLANT									
350.2	RIGHTS OF WAY	SQUARE	*	1,932.08	1,931	1	0	-	-
351.2	COMPRESSOR STATION STRUCTURES	65-R2.5	*	3,250,036.96	2,315,172	934,865	262,276	8.07	3.6
	WELLS								
352.01	CONSTRUCTION	SQUARE	*	738,941.36	738,926	15	4	0.00	3.8
352.02	EQUIPMENT	50-S2.5	*	168,031.87	168,032	0	0	-	-
	TOTAL ACCOUNT 352			906,973.23	906,958	15	4		
352.1	STORAGE LEASEHOLDS AND RIGHTS	SQUARE	*	206,940.78	206,932	9	3	0.00	3.0
353	LINES	50-S1.5	*	389,345.13	388,857	488	146	0.04	3.3
354	COMPRESSOR STATION EQUIPMENT	55-R2.5	*	948,176.70	820,261	127,916	36,118	3.81	3.5
355	MEASURING AND REGULATING EQUIPMENT	37-R1.5	*	104,476.92	104,477	0	0	-	-
	TOTAL UNDERGROUND STORAGE PLANT			**5,807,881.80**	**4,744,588**	**1,063,294**	**298,547**	**5.14**	
DISTRIBUTION PLANT									
	LAND AND LAND RIGHTS								
374.4	LAND RIGHTS	70-R2.5		3,691,925.24	845,600	2,846,325	61,806	1.67	46.1
374.5	RIGHTS OF WAY	80-S4		3,233,171.42	1,792,134	1,441,037	34,951	1.08	41.2
	TOTAL ACCOUNT 374			6,925,096.66	2,637,734	4,287,362	96,757	1.40	
	STRUCTURES AND IMPROVEMENTS								
375.34	MEASURING AND REGULATING	60-R1		5,935,978.81	1,444,261	4,491,718	130,802	2.20	34.3
375.6	INDUSTRIAL MEASURING AND REGULATING	55-R1		86,227.87	75,446	10,782	525	0.61	20.5
375.7	OTHER DISTRIBUTION SYSTEMS								
	DISTRIBUTION SYSTEM STRUCTURES	90-R1.5	*	24,400,946.92	3,067,318	21,333,630	719,259	2.95	29.7
	OTHER BUILDIINGS	35-R2		2,795,493.97	714,161	2,081,333	91,802	3.28	22.7
	TOTAL ACCOUNT 375.70			27,196,440.89	3,781,479	23,414,963	811,061	2.98	28.9
375.8	COMMUNICATION	45-R3		16,515.17	8,259	8,256	358	2.17	23.1
	TOTAL ACCOUNT 375			33,235,162.74	5,309,445	27,925,719	942,746	2.84	
376	MAINS								
	CAST IRON	71-R1	*	145,838.47	110,653	35,185	9,168	6.29	3.8
	BARE STEEL	71-R1	*	51,888,936.80	34,810,737	17,078,200	2,016,336	3.89	8.5
	OTHER	71-R1		2,129,009,705.14	257,443,741	1,871,565,964	46,100,766	2.17	40.6
	TOTAL ACCOUNT 376			2,181,044,480.41	292,365,131	1,888,679,349	48,126,270	2.21	
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	45-O1		126,103,757.33	20,581,541	105,522,216	4,809,836	3.81	21.9
379.1	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	35-S2		135,966.90	54,214	81,753	9,007	6.62	9.1
380	SERVICES								
	BARE STEEL	50-R0.5	*	568,798.90	428,787	140,012	19,407	3.41	7.2
	OTHER	50-R0.5		694,553,782.49	137,978,763	556,575,019	21,026,838	3.03	26.5
	TOTAL ACCOUNT 380			695,122,581.39	138,407,550	556,715,031	21,046,245	3.03	

COLUMBIA GAS OF PENNSYLVANIA, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF NOVEMBER 30, 2021

	DEPRECIABLE GROUP	SURVIVOR CURVE	ORIGINAL COST AS OF NOVEMBER 30, 2021	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
381	METERS	44-S1	41,638,535.60	17,845,972	23,792,564	994,418	2.39	23.9
381.1	METERS - AMR	15-S2.5	24,820,375.62	17,041,116	7,779,260	1,393,760	5.62	5.6
382	METER INSTALLATIONS	55-R3	42,452,170.64	15,035,037	27,417,134	796,701	1.88	34.4
383	HOUSE REGULATORS AND INSTALLATIONS	45-S2	18,993,073.78	7,831,229	11,161,845	386,985	2.04	28.8
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT - OTHER THAN METERS	30-R0.5	7,811,445.82	2,422,503	5,388,943	409,593	5.24	13.2
	OTHER EQUIPMENT							
387	GENERAL	32-R0.5	136,698.14	78,374	58,324	4,125	3.02	14.1
387.4	COMMUNICATION EQUIPMENT	25-R2	11,443,998.08	2,808,645	8,635,353	544,705	4.76	15.9
387.5	GPS EQUIPMENT	10-S3	2,201,371.95	1,551,363	650,009	208,260	9.46	3.1
	TOTAL ACCOUNT 387		13,782,068.17	4,438,382	9,343,686	757,090	5.49	
	TOTAL DISTRIBUTION PLANT		**3,192,064,715.06**	**523,969,854**	**2,668,094,862**	**79,769,408**	**2.50**	
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS - COMMUNICATION	45-R2	49,821.42	49,821	0	0	-	-
	OFFICE FURNITURE AND EQUIPMENT							
391.1	FURNITURE	20-SQ	2,285,833.24	1,137,743	1,148,090	86,259	3.77	13.3
391.11	EQUIPMENT	15-SQ	91,303.67	47,228	44,076	5,834	6.39	7.6
391.12	INFORMATION SYSTEMS	5-SQ	2,692,531.12	2,174,689	517,842	392,310	14.57	1.3
	TOTAL ACCOUNT 391		5,069,668.03	3,359,660	1,710,008	484,403	9.55	
392	TRANSPORTATION EQUIPMENT - TRAILERS	15-SQ	25,616.89	23,135	2,482	343	1.34	7.2
394	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	18,382,788.16	7,626,712	10,756,076	641,622	3.49	16.8
395	LABORATORY EQUIPMENT	20-SQ	266,039.42	83,221	182,818	13,871	5.21	13.2
396	POWER OPERATED EQUIPMENT	13-L2	948,698.04	896,018	52,680	16,758	1.77	3.1
397.5	COMMUNICATION EQUIPMENT - TELEMETERING	19-R2.5	1,677,225.06	659,240	1,017,985	73,354	4.37	13.9
398	MISCELLANEOUS EQUIPMENT	15-SQ	953,269.70	478,581	474,689	57,955	6.08	8.2
	TOTAL GENERAL PLANT		**27,373,126.72**	**13,176,388**	**14,196,738**	**1,288,306**	**4.71**	
	SUBTOTAL DEPRECIABLE PLANT		**3,225,245,723.58**	**541,890,830**	**2,683,354,894**	**81,356,261**	**2.52**	
AMORTIZABLE PLANT								
303	MISCELLANEOUS INTANGIBLE PLANT		32,302,002.60	17,029,312	15,272,691	5,791,961 **		
303.6	MISCELLANEOUS INTANGIBLE PLANT - CLOUD		9,051,102.42	1,291,101	7,760,001	2,127,422 **		
362.1	ENVIRONMENTAL REMEDIATION			(151,290)				
375.71	STRUCTURES AND IMPROVEMENTS - LEASED		5,607,225.91	2,501,391	3,105,835	488,178 **		
	SUBTOTAL AMORTIZABLE PLANT		**46,960,330.93**	**20,670,514**	**26,138,527**	**8,407,561**		
NONDEPRECIABLE PLANT			**3,533,240.78**	**234,731**				
	TOTAL GAS PLANT		**3,275,739,295.29**	**562,796,075**	**2,709,493,421**	**89,763,822**		

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

COLUMBIA GAS OF PENNSYLVANIA, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
DEPRECIABLE PLANT									
UNDERGROUND STORAGE PLANT									
350.2	RIGHTS OF WAY	SQUARE	*	1,932.08	1,931	1	0	-	-
351.2	COMPRESSOR STATION STRUCTURES	65-R2.5	*	3,250,036.96	2,603,950	646,087	259,722	7.99	2.5
	WELLS								
352.01	CONSTRUCTION	SQUARE	*	738,941.36	738,926	15	6	0.00	2.5
352.02	EQUIPMENT	50-S2.5	*	168,031.87	168,032	0	0	-	-
	TOTAL ACCOUNT 352			906,973.23	906,958	15	6		
352.1	STORAGE LEASEHOLDS AND RIGHTS	SQUARE	*	206,940.78	206,932	9	4	0.00	2.2
353	LINES	50-S1.5	*	389,345.13	389,211	134	54	0.01	2.5
354	COMPRESSOR STATION EQUIPMENT	55-R2.5	*	948,176.70	859,397	88,780	35,852	3.78	2.5
355	MEASURING AND REGULATING EQUIPMENT	37-R1.5	*	104,476.92	104,477	0	0	-	-
	TOTAL UNDERGROUND STORAGE PLANT			**5,807,881.80**	**5,072,856**	**735,026**	**295,638**	**5.09**	
DISTRIBUTION PLANT									
	LAND AND LAND RIGHTS								
374.4	LAND RIGHTS	70-R2.5		3,946,890.70	892,472	3,054,419	66,145	1.68	46.2
374.5	RIGHTS OF WAY	80-S4		3,233,171.42	1,829,962	1,403,209	34,846	1.08	40.3
	TOTAL ACCOUNT 374			7,180,062.12	2,722,434	4,457,628	100,991	1.41	
	STRUCTURES AND IMPROVEMENTS								
375.34	MEASURING AND REGULATING	60-R1		6,435,286.05	1,544,869	4,890,417	142,760	2.22	34.3
375.6	INDUSTRIAL MEASURING AND REGULATING	55-R1		86,227.87	76,129	10,099	500	0.58	20.2
375.7	OTHER DISTRIBUTION SYSTEMS								
	DISTRIBUTION SYSTEM STRUCTURES	90-R1.5	*	29,634,017.66	3,908,698	25,725,319	853,430	2.88	30.1
	OTHER BUILDIINGS	35-R2		3,133,253.41	785,235	2,348,018	104,091	3.32	22.6
	TOTAL ACCOUNT 375.70			32,767,271.07	4,693,933	28,073,337	957,521	2.92	29.3
375.8	COMMUNICATION	45-R3		16,515.17	8,647	7,868	355	2.15	22.2
	TOTAL ACCOUNT 375			39,305,300.16	6,323,578	32,981,721	1,101,136	2.80	
376	MAINS								
	CAST IRON	71-R1	*	96,846.26	76,333	20,513	7,139	7.37	2.9
	BARE STEEL	71-R1	*	38,527,425.95	27,412,916	11,114,510	1,475,713	3.83	7.5
	OTHER	71-R1		2,400,347,454.48	289,023,479	2,111,323,975	52,013,784	2.17	40.6
	TOTAL ACCOUNT 376			2,438,971,726.69	316,512,728	2,122,458,998	53,496,636	2.19	
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	45-O1		134,191,532.03	25,121,218	109,070,314	4,784,514	3.57	22.8
379.1	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	35-S2		135,966.90	80,501	55,466	6,350	4.67	8.7
380	SERVICES								
	BARE STEEL	50-R0.5	*	237,545.10	181,111	56,434	8,572	3.61	6.6
	OTHER	50-R0.5		790,211,673.64	151,081,036	639,130,638	24,320,101	3.08	26.3
	TOTAL ACCOUNT 380			790,449,218.74	151,262,147	639,187,072	24,328,673	3.08	

COLUMBIA GAS OF PENNSYLVANIA, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	DEPRECIABLE GROUP	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
381	METERS	44-S1	42,969,485.12	18,744,299	24,225,186	1,014,435	2.36	23.9
381.1	METERS - AMR	15-S2.5	25,088,513.31	18,559,238	6,529,275	1,263,887	5.04	5.2
382	METER INSTALLATIONS	55-R3	44,125,105.82	15,717,025	28,408,081	828,665	1.88	34.3
383	HOUSE REGULATORS AND INSTALLATIONS	45-S2	20,000,026.91	8,144,134	11,855,893	413,230	2.07	28.7
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT - OTHER THAN METERS	30-R0.5	8,980,037.20	2,828,185	6,151,852	447,861	4.99	13.7
	OTHER EQUIPMENT							
387	GENERAL	32-R0.5	136,698.14	82,846	53,852	3,812	2.79	14.1
387.4	COMMUNICATION EQUIPMENT	25-R2	11,443,998.08	3,400,839	8,043,159	520,824	4.55	15.4
387.5	GPS EQUIPMENT	10-S3	2,201,371.95	1,776,967	424,405	164,118	7.46	2.6
	TOTAL ACCOUNT 387		13,782,068.17	5,260,652	8,521,416	688,754	5.00	
	TOTAL DISTRIBUTION PLANT		**3,565,179,043.17**	**571,276,139**	**2,993,902,902**	**88,475,132**	**2.48**	
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS - COMMUNICATION	45-R2	49,821.42	49,821	0	0	-	-
	OFFICE FURNITURE AND EQUIPMENT							
391.1	FURNITURE	20-SQ	2,023,147.59	961,656	1,061,492	86,805	4.29	12.2
391.11	EQUIPMENT	15-SQ	91,303.67	53,548	37,756	5,827	6.38	6.5
391.12	INFORMATION SYSTEMS	5-SQ	367,127.23	151,198	215,929	136,731	37.24	1.6
	TOTAL ACCOUNT 391		2,481,578.49	1,166,402	1,315,177	229,363	9.24	
392	TRANSPORTATION EQUIPMENT - TRAILERS	15-SQ	25,616.89	20,483	5,134	983	3.84	5.2
394	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	17,712,799.00	5,212,486	12,500,313	715,597	4.04	17.5
395	LABORATORY EQUIPMENT	20-SQ	264,921.24	97,116	167,805	13,754	5.19	12.2
396	POWER OPERATED EQUIPMENT	13-L2	948,698.04	886,544	62,154	21,631	2.28	2.9
397.5	COMMUNICATION EQUIPMENT - TELEMETERING	19-R2.5	2,921,116.97	619,299	2,301,818	171,822	5.88	13.4
398	MISCELLANEOUS EQUIPMENT	15-SQ	944,904.75	532,483	412,422	57,834	6.12	7.1
	TOTAL GENERAL PLANT		**25,349,456.80**	**8,584,634**	**16,764,823**	**1,210,984**	**4.78**	
	SUBTOTAL DEPRECIABLE PLANT		**3,596,336,381.77**	**584,933,629**	**3,011,402,751**	**89,981,754**	**2.50**	
AMORTIZABLE PLANT								
303	MISCELLANEOUS INTANGIBLE PLANT		41,466,796.20	19,407,265	22,059,531	8,028,425 **		
303.6	MISCELLANEOUS INTANGIBLE PLANT - CLOUD		21,794,964.74	4,841,549	16,953,416	4,444,857 **		
362.1	ENVIRONMENTAL REMEDIATION			(84,044)				
375.71	STRUCTURES AND IMPROVEMENTS - LEASED		6,293,265.77	4,853,084	1,440,182	564,482 **		
	SUBTOTAL AMORTIZABLE PLANT		**69,555,026.71**	**29,017,854**	**40,453,129**	**13,037,764**		
NONDEPRECIABLE PLANT			**3,533,240.78**	**234,772**				
	TOTAL GAS PLANT		**3,669,424,649.26**	**614,186,255**	**3,051,855,880**	**103,019,518**		

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

N. SHULTZ

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

March 30, 2021

I. Introduction

Q. Please state your name and business address.

A. My name is Nicole M. Shultz and my business address is 290 West Nationwide Boulevard, 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. I am responsible for supporting the NiSource Inc. ("NiSource") operating companies in a variety of informational and rate filings, general rate case preparation and support, and other duties as assigned.

Q. What is your educational and professional background?

A. I have a Bachelors of Business Administration in Accounting and Financial Economics from Lincoln Memorial University, and a Master of Business Administration from Otterbein University. My career began at NiSource in 2001 providing General Accounting support for the various Columbia Gas Distribution Companies. In 2005, I worked for the Financial and Fraud Audit Divisions for the State of Ohio. Since rejoining NCSC in 2011, I've worked on General Accounting and Asset Accounting matters for NCSC and Columbia Distribution Companies, which includes Columbia Gas of Pennsylvania, Inc. ("Columbia" and the "Company") before transferring into my current Lead Regulatory Analyst role in 2019.

Q. Have you ever testified before a regulatory Commission?

A. I have provided direct testimony in Columbia's previous base rate proceeding at Docket No. R-2020-3018835.

II. <u>Statement of Purpose</u>

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

A. I will present schedules that demonstrate Columbia's rate base as of December 31, 2022, which reflects the Fully Projected Future Test Year ("FPFTY") investment level that is utilized within the revenue requirement supported by Witness Miller (Columbia Statement No. 4). My testimony will support and detail the various components included in rate base. I am also sponsoring the following exhibits:

Exhibit No.	Description
Exhibit No. 8	Historic Test Year rate base
Exhibit No. 13, Schedule 6 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 108	Future Test Year and Fully Projected Future Test Year rate base
Exhibit No. 113, Schedule 4 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 408, Page 1 (11)	AFUDC and method of rate calculation
Exhibit NMS-1 (Attached hereto)	Update of Ex. 108, Schedule 1 from Docket No. R-2020-3018835 (Updated through Dec. 31, 2020)

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

A. I will be addressing the twelve month period ending November 30, 2020 as the Historic Test Year (Exhibit 8), the twelve month period ended November 30, 2021 as the Future Test Year (Exhibit 108), and the twelve month period ended December 31, 2022 as the FPFTY (Exhibit 108).

III. <u>Rate Base</u>

Q. Is the FPFTY utilized by Columbia in this case similar to that used in its prior base rate cases?

A. Yes. Columbia elected to use the FPFTY provided in Act 11 of 2012 in Docket Nos. R-2012-2321748, R-2014-2406274, R-2015-2468056, R-2016-2529660, R-2018-2647577 and R-2020-3018835. The Company has made the same election in the current case. Also note, the presentation of rate base in this case is the same as the prior cases.

Q. Please describe Exhibit NMS-1.

A. Exhibit NMS-1 provides an update of Columbia Exhibit 108, Schedule 1, from Columbia's prior rate case at Docket No. R-2020-3018835. This exhibit includes actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2020. See Exhibit NMS-1.

Q. Please comment on how the Company's actual capital additions for the 12 month period ending November 30, 2020 (the HTY) compares to the projections made in Columbia's prior rate case at Docket No. R-2020-3018835.

A. The Company has exceeded the budget provided in the 2020 Rate Case 2020-3018835 for additions for the 12 months ending November 30, 2020, as shown in the table below.

Budget per 2020 Rate Case, 2020-3018835 Exhibit 108, Schedule 1				
	Budget	Actual	Over/(Under)	%
Additions	305,016,151	333,249,554	28,233,403	9.26%
Retirements	50,211,838	31,842,460	(18,379,377)	-36.60%
Total	254,794,313	301,407,094	46,612,780	18.29%

Q. Please explain the development of rate base at November 30, 2020 for the Historic Test Year, November 30, 2021 for the Future Test Year and December 31, 2022 for the FPFTY.

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 FPFTY are summarized on Exhibit 108, Page 3, and further detailed by various components in Exhibit 108, Schedules 1-10.

Q. Please discuss the amounts included in Property, Plant and Equipment for the Historic Test Year as illustrated on Exhibit 8, Page 3 Lines 1-9.

A. The Company's Plant in Service includes plant in service per books as of November 30, 2020. Accounts 101 and 106 are detailed in Lines 2 through 4. Note, the plant detail for Leases (Line 4) is separately provided as Leases are removed from rate base.

The Company is not making a claim for Construction Work in Progress ("CWIP") as of the end of the Historic Test Year as noted in Line 5. The Historic Test Year also includes per books Gas Stored Underground – Non-Current, Account 117 on Exhibit 8, Page 3, Line 6. Reductions are included for the reserve for depreciation, per Company witness Spanos (Columbia Statement No. 5) on Line 7. Finally, gas lost in underground storage is on Line 8.

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

A. The Company's Plant in Service as of December 31, 2022, as shown on Exhibit 108, Schedule 1, Page 14, Column 5, was developed beginning from Column 2 of Page 1 with Gas Plant in Service at November 30, 2020 (also shown on Exhibit 8, Page 3, Column 3). For purposes of presenting the FTY and FPFTY, the Account 101 and 106 information is combined in Line 2. Forecasted Plant in Service from December 2020 through December 2022 per the Company's forecasted budget are shown in Exhibit 108, Schedule 1, columns 3-85. The forecasted plant additions were provided based on the Company's current capital plan, Column 3 & 6. Forecasted retirements from December 2020 to December 2022, as supported by Company witness Spanos (Columbia Statement No. 5) are shown in Exhibit 108, Schedule 1, column 4 & 7. By adding forecasted Plant in Service and subtracting forecasted retirements, Exhibit 108, Schedule 1 reflects the net forecasted plant in service included in rate base as of

December 31, 2022, column 6. Additional details surrounding the budget is discussed by witness Brumley (Columbia Statement No. 7).

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 FPFTY as it was at November 30, 2020. The Company is making no claim for CWIP in the FPFTY.

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

A. Line 7, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the Historic Test Year and Line 6, Exhibit 108, Page 3 for the FPFTY are detailed and supplied by Company witness Spanos, by plant account, in Exhibit 5 for the Historic Test Year and Exhibit 105 in the FPFTY. Exhibit 8, Page 3, Line 8 and Exhibit 108, Page 3, Line 7 Accumulated Provision for Gas Lost – Underground Storage, Account 117, is per books as of November 30, 2020 for the Historic Test Year and December 31, 2022 for the FPFTY.

Q. Did you include Materials and Supplies inventory balances in rate base?

A. Yes. As shown on Exhibit 8, Schedule 5, Materials and Supplies included in the Historic Test Year rate base is a 13 month average of the historical monthly balances in Plant Materials, Account 154. Materials and Supplies in the Future Test Year rate base as shown on the Exhibit 108, Schedule 5 begins with November and December 2020 actual balances (most recently available), with January 2021 through November 2021 balances calculated by applying the Gross Domestic Product ("GDP") deflator supported by Company witness Miller (Columbia Statement No. 4) in Exhibit 104, Schedule 2, Page 20, to the actual balances of January 2020 through November 2020. The GDP deflator is further applied to the Future Test Year balances to arrive at the FPFTY balances.

Q. Did you include Prepayment balances in rate base?

A. Yes. Exhibit 8, Schedule 6 for the Historic Test Year shows prepayments for: Prepaid Leases, Account 16500000; Corporate Insurance, Account 16521000; Prepaid Insurance I/C, Account 1652000; Regulatory Commission Fees, Office of Consumer Advocate ("OCA") fees, and Office of Small Business Advocate ("OSBA") fees, Account 16503600; and Prepaid Permits, Account 16503700. The amount in the Historic Test Year rate base is based on a 13 month average of historic monthly balances per the Company's books. Exhibit 108, Schedule 6 for the FPFTY shows prepayments for: Prepaid Leases, Account 16500000; Corporate Insurance, Account 16521000; Prepaid Insurance I/C, Account 1652000; Regulatory Commission Fees, OCA, and OSBA fees, Account 16503600; and Prepaid Permits, Account 16503700. The amounts for the FPFTY rate base were determined by incrementally applying the GDP deflators supported by Company witness Miller in Exhibit 104, Schedule 2, Page

20 to the January 2020 through November 2020 actual balances to reflect expected new prepayments as of December 2022.

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 FPFTY 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 the 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 include 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 2019 through November 2020 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 of Exhibit 8, Schedule 7. 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 WACOG per Dth is calculated (Column D) for the current month. The current month's withdrawals (Column E) are multiplied by the new WACOG per Dth (Column D) and the result is deducted from the cumulative balance (Column G). This method is continued every month through November 2020, as shown in Exhibit 8, Schedule 7. Exhibit 8, Schedule 7, 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 2020 through December 2022. Injection rates are based on NYMEX Natural Gas Futures. Lines 27 and 28 calculate a twelve month average storage balance for the Future Test Year rate base and FPFTY rate base, respectively.

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

A. Yes, I did. Balances as of November 30, 2020 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 8, Schedule 8. The balances were supplied by Company witness Harding (Columbia Statement No. 10) on Exhibit 7, Page 9. Forecasted balances as of November 30, 2021 and December 31, 2022 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 108, Schedule 8. These were supplied by Company witness Harding on Exhibit 107, Page 5 .

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 2020 through December 2022, with entries for November and December of each year based on actual data for November and December of 2020. The balances for the months of January 2022 through October 2022 are the same as the balances in the month of January 2021 through October 2021 following the trend that deposits gradually go up in the winter and down in the summer. The balances for January 2021 – October 2022 are based on Historic Test Year balances.

Q. Please explain the Company's account for the Contributions in Aid of Construction and Customer Advances.

A. Customer Advances for Construction are classified to the 252 and 186 account. This includes advances by customers for construction which are to be refunded either wholly or in part. Once the customer advance is received it is journalized as a credit to the 252 account and a debit to Cash (account 131). The next month a journal entry is made to debit the 186 account and credit the Capital asset (Account 101). The calculation of rate base includes the Customer Advance 252 and 186 accounts as well as the Capital Asset (Account 101). Therefore, rate base has appropriately reduced amounts paid by Customers.

If the advance is refunded, then a debit is made against the Capital asset (Account 101) and the customer is issued a refund. Additionally an entry is made to reduce the balances in Account 186 and 252. However, if the customer advance is deemed non-refundable it becomes a Contribution in Aid of Construction and remains as a credit to the Capital asset.

Customer Advances for Construction are reflected on Exhibit 8 Page 3, line 24 for the HTY and Exhibit 108 Page 3, line 23 for the FTY and FPFTY.

IV. <u>Distribution Service Improvement Charge</u>

Q. Please describe the Distribution Service Improvement Charge ("DSIC").

A. The DSIC was designed to allow for recovery of reasonable and prudent costs incurred to repair, improve or replace eligible property which has been completed and placed in service, but which is not being recovered through base rates.

Q. Is Columbia currently charging a DSIC?

A. No. Columbia reset its DSIC to 0% when the Company made its compliance filing for the 2020 rate case at Docket No. 2020-3018835. However, Columbia filed Tariff Supplement No. 324 on March 19, 2021, to become effective April 1, 2021, to update the DSIC rate to recover the under collection from the Rider DSIC for the 12 months ended December 31, 2020.

Q. When will the Company be eligible to include plant additions in the DSIC?

A. Consistent with the Tariff, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC. Pursuant to the approved base rate increase in Docket No. R-2020-301885, the Company's base rates and rate base included projected balances (FPFTY) at December 31, 2021. The Company would be eligible to include plant additions in the DSIC once net plant additions of $261.78 million from the approved 2020 Rate Case, R-2020-301885 as of December 31, 2021 are exceeded.

V. Other Exhibits

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, which provides that Exhibit 8, Page 4, shows the Company's rate base claim from its last base rate proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2019 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 1/31/2020 (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	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	24,574,424	708,668	(132,678)	25,150,414	12,546	0	25,162,960
6	Cloud Software	303.99	0	0	0	0	0	0	0
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	477,100	2,884,000	0	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,082,273	92,478	(1,195)	3,173,555	0	(15)	3,173,540
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,161	10	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,184,456	45,984	(3,897)	5,226,544	16,580	(25)	5,243,099
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	9,917,104	7,792,012	(177,785)	17,531,331	0	0	17,531,331
30	Structures, Other Distribution System, Leased	375.71	5,487,917	298,012	(12,476)	5,773,453	8,461	0	5,781,914
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,688,863,735	33,297,345	*(5,884,107)*	1,716,276,974	12,190,430	*(740,000)*	1,727,727,404
34	Mains - CSL Replacements	376.08	23,574,504	0	0	23,574,504	0	(12,999)	23,561,505
35	Bare Steel	376.30	64,933,670	0	(334,938)	64,598,732	0	(797)	64,597,935
36	Cast Iron	376.80	263,240	0	(30,851)	232,389	0	0	232,389
37	Measuring & Regulating Equipment General	378.10	1,451,939	0	(4,347)	1,447,592	0	0	1,447,592
38	Measuring & Regulating Equipment Regulating	378.20	93,245,433	2,144,924	(233,777)	95,156,580	569,521	(25,026)	95,701,076
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	580,788,003	6,117,091	(2,320,491)	584,584,603	3,633,995	(14,172)	588,204,426
43	Meters	381.00	39,176,296	207,905	(64,825)	39,319,377	98,407	0	39,417,784
44	Auto Meter Reading Devices	381.10	24,570,547	2,044	0	24,572,591	0	0	24,572,591
45	Meter Installations	382.00	40,589,166	110,292	(29,106)	40,670,352	39,888	0	40,710,240
46	House Regulators	383.00	13,686,795	96,958	(1,248)	13,782,505	77,854	0	13,860,358
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,362,985	14	(9,683)	6,353,316	57	(31,185)	6,322,188
49	Industrial M&R Equipment. Large Volume	385.10	1,579,956	(531,978)	(3,683)	1,044,295	40	0	1,044,335
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	627,560	0	(3,628)	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	9,519,187	7,436	(3,258)	9,523,365	8,300	0	9,531,665
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	**General Plant**								
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,380,973	0	(2,000)	2,378,973	0	0	2,378,973
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,498,635	12,140	(319,479)	4,191,295	512	0	4,191,807
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	57,458	0	(686)	56,772	0	0	56,772
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,345,764	289,521	(89,303)	16,545,982	63,090	(71,865)	16,537,208
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	792,133	0	(4,217)	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	971,183	0	0	971,183	0	0	971,183
80	**Total Gas Plant in Service**		2,687,846,103	53,574,856	(9,667,656)	2,731,753,304	16,719,682	(896,084)	2,747,576,901

1/ In December 2019 an over retirement of $9.5 million was made in GPA 376-Mains. A correction was made in January 2020 to reflect the proper activity for December 2019, which was (9,667,656).

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 1/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 2/28/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 3/31/2020 (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	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	25,162,960	765,624	0	25,928,584	37,570	(12,330)	25,953,825
6	Cloud Software	303.99	0			0	1,408,697	0	1,408,697
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	0	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,173,540	20,845	0	3,194,385	0	0	3,194,385
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,243,099	35,161	0	5,278,260	76,801	(25,320)	5,329,741
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,531,331	0	0	17,531,331	73,458	0	17,604,788
30	Structures, Other Distribution System, Leased	375.71	5,781,914	0	0	5,781,914	0	0	5,781,914
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,727,727,404	23,476,727	(267,135)	1,750,936,996	15,261,993	(394,769)	1,765,804,219
34	Mains - CSL Replacements	376.08	23,561,505	0	(46,024)	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,597,935	0	(41,790)	64,556,145	6	(51,398)	64,504,753
36	Cast Iron	376.80	232,389	0	(3,758)	228,631	0	(7,828)	220,803
37	Measuring & Regulating Equipment General	378.10	1,447,592	0	0	1,447,592	0	0	1,447,592
38	Measuring & Regulating Equipment Regulating	378.20	95,701,076	369,478	(4,931)	96,065,622	490,974	(7,307)	96,549,289
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	588,204,426	4,153,899	(740,823)	591,617,502	5,587,865	(1,868,751)	595,336,616
43	Meters	381.00	39,417,784	202,977	(78,018)	39,542,742	153,114	(126,876)	39,568,980
44	Auto Meter Reading Devices	381.10	24,572,591	30,355	0	24,602,946	881	0	24,603,826
45	Meter Installations	382.00	40,710,240	38,711	(5,018)	40,743,934	79,589	(9,354)	40,814,168
46	House Regulators	383.00	13,860,358	88,375	(442)	13,948,291	81,534	(1,319)	14,028,506
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,322,188	0	(30,853)	6,291,335	13,064	(36,174)	6,268,225
49	Industrial M&R Equipment. Large Volume	385.10	1,044,335	2,682	(1,297)	1,045,720	1,022	(4,534)	1,042,209
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	9,531,665	32,139	(5,940)	9,557,864	300	(9,552)	9,548,612
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	**General Plant**			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,378,973	0	(1,062)	2,377,912	0	(53,063)	2,324,849
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,191,807	0	0	4,191,807	1,024	0	4,192,831
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	56,772	0	0	56,772	0	0	56,772
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,537,208	77,155	0	16,614,363	56,238	0	16,670,600
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	971,183	0	(6,911)	964,272	0	0	964,272
80	**Total Gas Plant in Service**		2,747,576,901	29,294,128	(1,234,003)	2,775,637,027	23,324,128	(2,608,576)	2,796,352,579

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 3/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2020 (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	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	25,953,825	70,696	(142,874)	25,881,646	742,550.76	0	26,624,197
6	Cloud Software	303.99	1,408,697	20,594	0	1,429,291	1,181.97	0	1,430,473
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	0	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,194,385	1,500	(73)	3,195,813	6,107.73	0	3,201,920
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,329,741	5,022	(7,920)	5,326,843	94,704.80	(40,908.81)	5,380,639
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,604,788	74,849	0	17,679,637	52.86	0	17,679,690
30	Structures, Other Distribution System, Leased	375.71	5,781,914	35,382	0	5,817,296	0	0	5,817,296
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,765,804,219	1,041,544	(519,097)	1,766,326,666	9,154,194.45	(391,248.38)	1,775,089,612
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,504,753	3	(20,445)	64,484,310	0.28	(10,117.08)	64,474,194
36	Cast Iron	376.80	220,803	0	0	220,803	0	0	220,803
37	Measuring & Regulating Equipment General	378.10	1,447,592	0	0	1,447,592	0	0	1,447,592
38	Measuring & Regulating Equipment Regulating	378.20	96,549,289	1,418,087	(9,344)	97,958,033	2,390,448.69	(20,571.55)	100,327,910
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	(4,967)	449,950	0	0	449,950
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	595,336,616	522,565	(507,663)	595,351,518	2,982,666.50	(733,150.84)	597,601,033
43	Meters	381.00	39,568,980	41,745	(55,228)	39,555,497	0	(55,550.83)	39,499,946
44	Auto Meter Reading Devices	381.10	24,603,826	0	0	24,603,826	11,943.71	0	24,615,770
45	Meter Installations	382.00	40,814,168	31,103	(1,835)	40,843,437	63,540.64	(4,197.81)	40,902,779
46	House Regulators	383.00	14,028,506	27,712	(207)	14,056,011	86,841.90	(295.37)	14,142,557
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,268,225	51,956	(20,913)	6,299,268	18,419.58	(10,555.28)	6,307,132
49	Industrial M&R Equipment. Large Volume	385.10	1,042,209	2,697	0	1,044,906	(0.94)	(2,068.73)	1,042,836
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	9,548,612	(551)	0	9,548,061	126,175.04	0	9,674,236
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	**General Plant**			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,324,849	0	(804)	2,324,045	0	0	2,324,045
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,192,831	(254)	0	4,192,577	0	0	4,192,577
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	56,772	0	0	56,772	0	0	56,772
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,670,600	158,689	0	16,829,289	25,476.99	(9,794.42)	16,844,972
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	(2,990)	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	964,272	0	(1,206)	963,066	0	0	963,066
80	**Total Gas Plant in Service**		2,796,352,579	3,503,338	(1,295,565)	2,798,560,352	15,704,305	(1,278,459)	2,812,986,198

Columbia Gas of Pennsylvania, Inc.
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			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 5/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2020 (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	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	26,624,197	310,345	(51,696)	26,882,845	149,949	(234,933)	26,797,861
6	Cloud Software	303.99	1,430,473	111	0	1,430,584	27,578	0	1,458,162
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	0	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,201,920	2,000	0	3,203,920	0	(4)	3,203,917
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,380,639	22,120	0	5,402,759	7,277	0	5,410,035
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,679,690	16,650	0	17,696,340	0	0	17,696,340
30	Structures, Other Distribution System, Leased	375.71	5,817,296	0	0	5,817,296	0	0	5,817,296
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,775,089,612	22,097,400	(404,099)	1,796,782,914	9,462,913	(498,666)	1,805,747,161
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,474,194	6	(34,045)	64,440,155	386	(63,406)	64,377,134
36	Cast Iron	376.80	220,803	0	0	220,803	0	0	220,803
37	Measuring & Regulating Equipment General	378.10	1,447,592	0	0	1,447,592	0	(2,936)	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	100,327,910	(221,239)	(1,127)	100,105,544	933,769	(7,914)	101,031,399
39	Measuring & Regulating Equipment Local Gas	378.30	449,950	0	0	449,950	0	(9,589)	440,361
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	597,601,033	5,823,181	(1,106,108)	602,318,107	4,738,744	(942,271)	606,114,580
43	Meters	381.00	39,499,946	122,741	(47,631)	39,575,057	424,665	(41,624)	39,958,099
44	Auto Meter Reading Devices	381.10	24,615,770	4,431	0	24,620,201	0	0	24,620,201
45	Meter Installations	382.00	40,902,779	44,786	(7,706)	40,939,860	84,312	(9,917)	41,014,254
46	House Regulators	383.00	14,142,557	63,214	(698)	14,205,074	77,416	(1,461)	14,281,029
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,307,132	4,866	(60,970)	6,251,028	8,032	(92,486)	6,166,574
49	Industrial M&R Equipment. Large Volume	385.10	1,042,836	(40)	(314)	1,042,482	0	(1,401)	1,041,080
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	9,674,236	124,468	0	9,798,703	181,003	(9,105)	9,970,600
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	**General Plant**			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,324,045	0	(636)	2,323,409	0	(12,937)	2,310,472
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,192,577	128	0	4,192,705	7,076	0	4,199,781
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	56,772	0	0	56,772	0	0	56,772
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,844,972	11,361	(9,829)	16,846,504	45,870	(16,826)	16,875,548
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	963,066	0	0	963,066	0	(9,796)	953,270
80	**Total Gas Plant in Service**		2,812,986,198	28,426,528	(1,724,857)	2,839,687,869	16,148,989	(1,955,272)	2,853,881,586

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			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 7/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 8/31/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 9/30/2020 (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	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	26,797,861	731,835	0	27,529,696	58,059	(174,258)	27,413,496
6	Cloud Software	303.99	1,458,162	235,528	0	1,693,690	269	0	1,693,959
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	29,179	0	3,250,037	0	0	3,250,037
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	0	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,203,917	0	0	3,203,917	0	(1,079)	3,202,837
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,410,035	229	0	5,410,265	17,714	0	5,427,979
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,696,340	0	0	17,696,340	25,742	0	17,722,082
30	Structures, Other Distribution System, Leased	375.71	5,817,296	0	0	5,817,296	939	0	5,818,235
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,805,747,161	41,604,399	(365,519)	1,846,986,041	15,565,000	(1,064,488)	1,861,486,553
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,377,134	1	(43,571)	64,333,564	30	(56,929)	64,276,666
36	Cast Iron	376.80	220,803	0	(629)	220,174	0	(3,594)	216,579
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	101,031,399	1,972,310	(39,499)	102,964,209	4,085,360	(32,329)	107,017,241
39	Measuring & Regulating Equipment Local Gas	378.30	440,361	0	0	440,361	0	(1,858)	438,503
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	606,114,580	7,094,850	(123,885)	613,085,545	6,685,635	(2,369,393)	617,401,788
43	Meters	381.00	39,958,099	225,050	(18,104)	40,165,045	9,786	(19,317)	40,155,515
44	Auto Meter Reading Devices	381.10	24,620,201	1,533	0	24,621,734	1,073	0	24,622,807
45	Meter Installations	382.00	41,014,254	39,805	(7,544)	41,046,516	58,267	(8,183)	41,096,599
46	House Regulators	383.00	14,281,029	69,673	(775)	14,349,927	99,880	(780)	14,449,027
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,166,574	7,084	(203,714)	5,969,944	37,932	(91,557)	5,916,319
49	Industrial M&R Equipment. Large Volume	385.10	1,041,080	0	0	1,041,080	0	0	1,041,080
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	9,970,600	14,432	(6,699)	9,978,334	335,736	(8,071)	10,305,999
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	**General Plant**			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,310,472	0	0	2,310,472	0	0	2,310,472
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,199,781	0	0	4,199,781	12,828	0	4,212,609
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	56,772	0	0	56,772	0	0	56,772
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,875,548	49,451	(5,290)	16,919,709	37,254	(50,994)	16,905,970
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	**Total Gas Plant in Service**		2,853,881,586	52,075,360	(815,228)	2,905,141,718	27,031,505	(3,882,831)	2,928,290,392

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			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 9/30/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 10/31/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 11/30/2020 (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	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	27,413,496	345,284	(11,749)	27,747,031	599,681	(614,447)	27,732,265
6	Cloud Software	303.99	1,693,959	24,314		1,718,273	940		1,719,212
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,250,037	0	0	3,250,037	0	0	3,250,037
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	(96)	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	0	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,202,837	95,036	0	3,297,873	56,209	(1,054)	3,353,028
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,427,979	8,395	(3,465)	5,432,909	93,323	(4,960)	5,521,273
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,722,082	0	0	17,722,082	0	0	17,722,082
30	Structures, Other Distribution System, Leased	375.71	5,818,235	1,090	0	5,819,325	(37)	0	5,819,288
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,861,486,553	21,829,002	(1,236,378)	1,882,079,177	23,325,250	(649,848)	1,904,754,580
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,276,666	1	(91,723)	64,184,944	1	(55,398)	64,129,547
36	Cast Iron	376.80	216,579	0	(10,712)	205,867	0	0	205,867
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	107,017,241	1,068,841	(105,989)	107,980,092	3,029,067	(29,878)	110,979,281
39	Measuring & Regulating Equipment Local Gas	378.30	438,503	0	0	438,503	0	0	438,503
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	617,401,788	8,364,696	(1,294,502)	624,471,982	7,224,762	(1,236,488)	630,460,256
43	Meters	381.00	40,155,515	7,652	(42,067)	40,121,101	644,660	(22,757)	40,743,004
44	Auto Meter Reading Devices	381.10	24,622,807	0	0	24,622,807	22,389	0	24,645,195
45	Meter Installations	382.00	41,096,599	110,479	(8,392)	41,198,687	80,382	(8,464)	41,270,605
46	House Regulators	383.00	14,449,027	103,035	(825)	14,551,237	104,398	(672)	14,654,963
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,916,319	36,445	(25,432)	5,927,333	80,877	(47,735)	5,960,476
49	Industrial M&R Equipment. Large Volume	385.10	1,041,080	0	0	1,041,080	1	(3,111)	1,037,970
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,305,999	691	0	10,306,690	50,361	(30,716)	10,326,335
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	**General Plant**			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,310,472	0	(1,178)	2,309,294	0	(3,978)	2,305,316
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,212,609	0	0	4,212,609	3	(941,918)	3,270,694
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	56,772	4,112	0	60,884	0	0	60,884
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,905,970	90,183	0	16,996,153	45,212	0	17,041,365
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	**Total Gas Plant in Service**		2,928,290,392	32,089,257	(2,832,507)	2,957,547,142	35,357,479	(3,651,423)	2,989,253,197

Columbia Gas of Pennsylvania, Inc.
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			Gas Plant in Service			
Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2020 (5 = 2+3+4) $
1	**Intangible Plant**					
2	Organization Costs	301.00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	27,732,265	259,968	0	27,992,233
6	Cloud Software	303.99	1,719,212	3,281		1,722,494
7	**Underground Storage Plant**					
8	Land	350.10	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,250,037	0	0	3,250,037
11	Wells Construction	352.01	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
18	**Distribution Plant**					
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,353,028	72,912	0	3,425,940
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,521,273	69,554	0	5,590,827
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,722,082	64,013	0	17,786,096
30	Structures, Other Distribution System, Leased	375.71	5,819,288	79,207	0	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515
32	Mains:					
33	Mains	376.00	1,904,754,580	23,954,331	(14,053,325)	1,914,655,585
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,129,547	162	(313,970)	63,815,739
36	Cast Iron	376.80	205,867	0	(8,798)	197,070
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	110,979,281	2,444,905	(46,370)	113,377,816
39	Measuring & Regulating Equipment Local Gas	378.30	438,503	0	(1,010)	437,493
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
42	Services	380.00	630,460,256	8,297,612	(1,113,401)	637,644,467
43	Meters	381.00	40,743,004	83,612	(34,168)	40,792,448
44	Auto Meter Reading Devices	381.10	24,645,195	0	0	24,645,195
45	Meter Installations	382.00	41,270,605	119,516	(11,362)	41,378,759
46	House Regulators	383.00	14,654,963	120,648	(616)	14,774,996
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,960,476	60,570	(29,537)	5,991,509
49	Industrial M&R Equipment. Large Volume	385.10	1,037,970	0	0	1,037,970
50	Other Equipment	387.10	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,326,335	124,238	(9,553)	10,441,021
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
57	**General Plant**			0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,305,316	0	(22,490)	2,282,826
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,270,694	169,701	0	3,440,394
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	60,884	0	0	60,884
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	17,041,365	24,880	(9,213)	17,057,031
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270
80	**Total Gas Plant in Service**		**2,989,253,197**	**35,949,113**	**(15,653,812)**	**3,009,548,498**

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

SUMMARY

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 11/30/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2020 (5 = 2+3+4) $
1	Intangible Plant					
2	Organization Costs	301.00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	24,574,424	4,792,775	(1,374,966)	27,992,233
6	Cloud Software	303.99	0	1,722,494	0	1,722,494
7	Underground Storage Plant					
8	Land	350.10	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	29,179	0	3,250,037
11	Wells Construction	352.01	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,272	0	(96)	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
18	Distribution Plant					
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	477,100	2,884,000	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,082,273	347,087	(3,419)	3,425,940
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
24	Rights of Way	374.50	3,233,161	10	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
27	Structures, Regulating	375.40	5,184,456	492,866	(86,495)	5,590,827
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	9,917,104	8,046,776	(177,785)	17,786,096
30	Structures, Other Distribution System, Leased	375.71	5,487,917	423,054	(12,476)	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515
32	Mains:					
33	Mains	376.00	1,688,863,735	252,260,528	(26,468,678)	1,914,655,585
34	Mains - CSL Replacements	376.08	23,574,504	0	(59,023)	23,515,481
35	Bare Steel	376.30	64,933,670	596	(1,118,527)	63,815,739
36	Cast Iron	376.80	263,240	0	(66,170)	197,070
37	Measuring & Regulating Equipment General	378.10	1,451,939	0	(7,283)	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	93,245,433	20,696,447	(564,064)	113,377,816
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	(17,424)	437,493
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
42	Services	380.00	580,788,003	71,227,562	(14,371,098)	637,644,467
43	Meters	381.00	39,176,296	2,222,315	(606,164)	40,792,448
44	Auto Meter Reading Devices	381.10	24,570,547	74,648	0	24,645,195
45	Meter Installations	382.00	40,589,166	900,670	(111,078)	41,378,759
46	House Regulators	383.00	13,686,795	1,097,539	(9,339)	14,774,996
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,362,985	319,318	(690,794)	5,991,509
49	Industrial M&R Equipment. Large Volume	385.10	1,579,956	(525,576)	(16,410)	1,037,970
50	Other Equipment	387.10	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	627,560	0	(3,628)	623,932
54	Other Equipment, Telemetering	387.45	9,519,187	1,004,728	(82,894)	10,441,021
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
57	General Plant					
58	Structures, Communications	390.10	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,380,973	0	(98,147)	2,282,826
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,498,635	203,157	(1,261,397)	3,440,394
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	57,458	4,112	(686)	60,884
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,345,764	974,381	(263,114)	17,057,031
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	(2,990)	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0
78	Communication Equipment, Telemetering	397.50	792,133	0	(4,217)	787,916
79	Miscellaneous Equipment	398.00	971,183	0	(17,913)	953,270
80	Total Gas Plant in Service		2,687,846,103	369,198,667	(47,496,273)	3,009,548,498

1/ In December 2019 an over retirement of $9.5 million was made in GPA 376-Mains. A correction was made in January 2020 to reflect the proper activity for December 2019, which was (9,667,656).

COLUMBIA STATEMENT NO. 6-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

REBUTTAL TESTIMONY OF
NICOLE SHULTZ
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

Q. Please state your name and business address.

A. My name is Nicole M. Shultz and my business address is 290 West Nationwide Boulevard, 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. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Witness David J. Effron, filed on behalf of the Office of Consumer Advocate ("OCA"). Specifically, I will address Mr. Effron's adjustment to the Company's Future Test Year ("FTY") and Fully Projected Future Test Year ("FPFTY") rate base. I will also address the recommendation of Ethan H. Cline, witness for the Bureau of Investigation and Enforcement ("I&E"), that the Company provide an update to Columbia Exhibit No. 108, Schedule 1.

Additionally, I am providing an update to Rate Base, which has been updated to incorporate the updated Deferred Income Tax number for HTY, FTY, and FPFTY. The change in deferred income taxes will be discussed by witness Jennifer Harding (Columbia Statement No. 10-R).

Q. Please summarize Mr. Effron's adjustment to the FTY and FPFTY rate

base.

A. Mr. Effron asserts that the Company's forecasted plant additions for the FTY and FPFTY (i.e.,2021 and 2022, respectively) are unreasonable because they exceed the Company's actual plant additions made in 2019 and 2020. As such, Mr. Effron recommends that the Company's forecasted plant additions for 2021 and 2022 be disregarded and that instead the forecasted plant additions for the FTY and FPFTY be based on an estimate that is calculated based on the average plant additions for the years 2019 and 2020. Mr. Effron's recommended approach to estimating the FTY and FPFTY plant additions results in a negative adjustment of $87,471,000 to the Company's FPFTY forecasted plant additions.

Q. Do you agree with Mr. Effron's recommendation to estimate the Company's forecasted plant additions for the FTY and FPFTY? Please explain.

A. No, I do not. Mr. Effron's recommendation to base the Company's forecasted plant additions for the FTY and FPFTY by averaging the plant additions for the years 2019 and 2020 stems merely from the Company's forecasted plant additions for the FTY and FPFTY exceeding the plant additions for the two preceding years. Mr. Effron has offered no evidence that the Company will not complete its 2021 and 2022 forecasted plant additions, and as explained in the rebuttal testimony of Mr. Kempic, past experience demonstrates the Company's success in executing its capital budgets. I have included Exhibit NMS-1, which shows that through May 31, 2021, the Company has exceeded its projections submitted in the 2020 Rate Case (Docket R-2020-3018835).

Moreover, Company witness Brumley, in his rebuttal testimony, justifies the Company's 2021 and 2022 forecasted plant additions by explaining how the planned additions are both necessary and reasonable, and related to safety and reliability. Mr. Brumley further testifies that the Company is either in the process of or prepared to execute the planned additions for the remainder of 2021 and 2022. Mr. Effron's recommendation should therefore be rejected as it is not proper to base the 2021 and 2022 forecasted plant additions on a historical average when the Company has supported its forecasts.

Q. What is the percentage of 2021 and 2022 additions that Mr. Effron is proposing as an adjustment to Plant in Service?

A. The proposed adjustment to the FTY and FPFTY Plant in Service by Mr. Effron represents approximately 15% of the $335,340,267 forecasted plant additions for 2021 and 12% of the $324,535,888 forecasted plant additions for 2022.

Q. Earlier you stated that you will address I&E witness Cline's recommendation that the Company update Columbia Exhibit No. 108, Schedule 1. What is your position regarding Mr. Cline's recommendation?

A. Specifically, Mr. Cline recommends that the Company update Exhibit No. 108, Schedule 1 no later than April 1, 2022, to include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2021, as well as provide an additional update for actuals through December 31, 2022 by April 1, 2023. The Company is agreeable to providing such updates to Exhibit 108.

Q. Do you have a new Exhibit to present due to the updated change in Deferred Income Taxes?

A. Yes, see Exhibit NMS-2 for updated Exhibit 108 Page 3 and Exhibit 108 Schedule 8.

Q. Does this complete your Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Property, Plant & Equipment - Budget to Actual Comparison
2020 Rate Case at Docket R-2020-3018835

Additions

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cumulative (3) ($)	Actuals Month (4) ($)	Actuals Cumulative (5) ($)	Month Over (Under) Budget (6)=(4-2) ($)	Cumulative Spend Over (Under) Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
1	12/31/2019	54,298,227	54,298,227	53,574,856	53,574,856	(723,371)	(723,371)	-1.33%
2	1/31/2020	5,389,425	59,687,653	16,719,682	70,294,538	11,330,256	10,606,885	17.77%
3	2/29/2020	9,889,384	69,577,036	29,294,128	99,588,665	19,404,744	30,011,629	43.13%
4	3/31/2020	15,216,024	84,793,061	23,324,128	122,912,794	8,108,104	38,119,733	44.96%
5	4/30/2020	16,852,955	101,646,016	3,503,338	126,416,132	(13,349,617)	24,770,117	24.37%
6	5/31/2020	19,609,506	121,255,521	15,704,305	142,120,437	(3,905,201)	20,864,916	17.21%
7	6/30/2020	26,228,364	147,483,885	28,426,528	170,546,965	2,198,165	23,063,080	15.64%
8	7/31/2020	22,912,256	170,396,141	16,148,989	186,695,954	(6,763,267)	16,299,813	9.57%
9	8/31/2020	24,805,552	195,201,693	52,075,360	238,771,314	27,269,808	43,569,621	22.32%
10	9/30/2020	32,007,612	227,209,305	27,031,505	265,802,819	(4,976,107)	38,593,513	16.99%
11	10/31/2020	51,312,212	278,521,517	32,089,257	297,892,075	(19,222,955)	19,370,558	6.95%
12	11/30/2020	26,494,634	305,016,151	35,357,479	333,249,554	8,862,845	28,233,403	9.26%
13	12/31/2020	72,804,720	377,820,871	35,949,113	369,198,667	(36,855,607)	(8,622,204)	-2.28%
14	1/31/2021	6,267,925	384,088,796	19,927,277	389,125,944	13,659,353	5,037,149	1.31%
15	2/28/2021	11,501,396	395,590,192	11,368,802	400,494,747	(132,594)	4,904,555	1.24%
16	3/31/2021	17,696,303	413,286,495	14,731,636	415,226,383	(2,964,666)	1,939,888	0.47%
17	4/30/2021	19,006,958	432,293,453	23,067,345	438,293,728	4,060,387	6,000,275	1.39%
18	5/31/2021	22,212,839	454,506,292	23,443,414	461,737,142	1,230,575	7,230,850	1.59%

Retirements

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cumulative (3) ($)	Actuals Month (4) ($)	Actuals Cumulative (5) ($)	Month (Over) Under Budget (6)=(4-2) ($)	Cumulative (Over) Under Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
1	12/31/2019	(19,169,712)	(19,169,712)	(9,667,656)	(9,667,656)	9,502,056	9,502,056	-49.57%
2	1/31/2020	(1,749,026)	(20,918,738)	(896,084)	(10,563,740)	852,942	10,354,998	-49.50%
3	2/29/2020	(2,040,708)	(22,959,446)	(1,234,003)	(11,797,742)	806,705	11,161,704	-48.61%
4	3/31/2020	(2,700,662)	(25,660,108)	(2,608,576)	(14,406,318)	92,086	11,253,790	-43.86%
5	4/30/2020	(2,388,412)	(28,048,520)	(1,295,565)	(15,701,883)	1,092,847	12,346,636	-44.02%
6	5/31/2020	(2,439,076)	(30,487,596)	(1,278,459)	(16,980,342)	1,160,617	13,507,253	-44.30%
7	6/30/2020	(3,121,160)	(33,608,756)	(1,724,857)	(18,705,200)	1,396,303	14,903,556	-44.34%
8	7/31/2020	(2,777,169)	(36,385,925)	(1,955,272)	(20,660,471)	821,897	15,725,454	-43.22%
9	8/31/2020	(2,983,963)	(39,369,888)	(815,228)	(21,475,699)	2,168,735	17,894,189	-45.45%
10	9/30/2020	(2,857,996)	(42,227,884)	(3,882,831)	(25,358,530)	(1,024,835)	16,869,353	-39.95%
11	10/31/2020	(5,001,447)	(47,229,331)	(2,832,507)	(28,191,037)	2,168,940	19,038,294	-40.31%
12	11/30/2020	(2,992,507)	(50,221,838)	(3,651,423)	(31,842,460)	(658,916)	18,379,377	-36.60%
13	12/31/2020	(3,524,660)	(53,746,498)	(15,653,812)	(47,496,273)	(12,129,152)	6,250,226	-11.63%
14	1/31/2021	(2,097,714)	(55,844,212)	(1,963,421)	(49,459,694)	134,293	6,384,519	-11.43%
15	2/28/2021	(2,436,591)	(58,280,803)	(1,118,998)	(50,578,692)	1,317,593	7,702,111	-13.22%
16	3/31/2021	(3,205,059)	(61,485,862)	(1,704,733)	(52,283,424)	1,500,326	9,202,437	-14.97%
17	4/30/2021	(2,908,273)	(64,394,135)	(1,808,751)	(54,092,175)	1,099,522	10,301,960	-16.00%
18	5/31/2021	(3,321,014)	(67,715,149)	(3,326,666)	(57,418,841)	(5,652)	10,296,308	-15.21%

Columbia Gas of Pennsylvania, Inc.
Property, Plant & Equipment - Budget to Actual Comparison
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Net Plant in Service

		Budget		Actuals		Month	Cumulative	
Ln. No.	Month	Month	Cumulative	Month	Cumulative	Over (Under) Budget	Over (Under) Budget	Over (Under)
	(1)	(2)	(3)	(4)	(5)	(6)=(4-2)	(7)=(5-3)	(8)=(7/3)
		($)	($)	($)	($)	($)	($)	(%)
1	12/31/2019	35,128,516	35,128,516	43,907,200	43,907,200	8,778,685	8,778,685	24.99%
2	1/31/2020	3,640,399	38,768,915	15,823,598	59,730,798	12,183,198	20,961,883	54.07%
3	2/29/2020	7,848,676	46,617,590	28,060,125	87,790,923	20,211,450	41,173,333	88.32%
4	3/31/2020	12,515,362	59,132,953	20,715,552	108,506,476	8,200,190	49,373,523	83.50%
5	4/30/2020	14,464,543	73,597,496	2,207,773	110,714,249	(12,256,770)	37,116,753	50.43%
6	5/31/2020	17,170,430	90,767,926	14,425,846	125,140,095	(2,744,584)	34,372,169	37.87%
7	6/30/2020	23,107,204	113,875,129	26,701,671	151,841,766	3,594,467	37,966,636	33.34%
8	7/31/2020	20,135,087	134,010,216	14,193,717	166,035,482	(5,941,370)	32,025,266	23.90%
9	8/31/2020	21,821,589	155,831,805	51,260,132	217,295,615	29,438,543	61,463,809	39.44%
10	9/30/2020	29,149,616	184,981,422	23,148,674	240,444,288	(6,000,943)	55,462,867	29.98%
11	10/31/2020	46,310,765	231,292,186	29,256,750	269,701,038	(17,054,015)	38,408,852	16.61%
12	11/30/2020	23,502,127	254,794,313	31,706,055	301,407,094	8,203,929	46,612,780	18.29%
13	12/31/2020	69,280,060	324,074,373	20,295,301	321,702,395	(48,984,759)	(2,371,979)	-0.73%
14	1/31/2021	4,170,210	328,244,584	17,963,856	339,666,251	13,793,646	11,421,667	3.48%
15	2/28/2021	9,064,805	337,309,389	10,249,804	349,916,055	1,184,999	12,606,666	3.74%
16	3/31/2021	14,491,244	351,800,633	13,026,904	362,942,959	(1,464,340)	11,142,326	3.17%
17	4/30/2021	16,098,685	367,899,318	21,258,594	384,201,553	5,159,909	16,302,235	4.43%
18	5/31/2021	18,891,825	386,791,143	20,116,748	404,318,301	1,224,923	17,527,158	4.53%

Original: Exhibit 108 Page 3 of 11

Columbia Gas of Pennsylvania, Inc.
Statement of Rate Base at Present Rates
December 31, 2022

Line No.	Acct. No.	Description	Pro forma November 30, 2020 (1) $		Adjustments (2) $		Pro Forma November 30, 2021 (3) $		Adjustments (4) $		Pro Forma December 31, 2022 (5) $		Reference (6)
1		**Property Plant and Equipment**											
2	101, 106	Gas Plant in Service	2,989,253,197		286,486,090		3,275,739,287		393,685,365		3,669,424,653		Exh 108, Schedule 1
3	101	Gas Plant in Service -Leases	0		0		0		0		0		
4	107	Construction Work in Progress - In Service	0		0		0		0		0		Exh 108, Schedule 2
5	117/191	Gas Stored Underground - Non-Current	3,794,693		0		3,794,693		0		3,794,693		
6	108-111	Depreciation Reserve	(541,097,323)		(21,698,752)		(562,796,075)		(51,390,180)		(614,186,255)		Exh 108, Schedule 3
7	117	Accum. Provision Gas Lost - Underground Storage	(163,467)		0		(163,467)		0		(163,467)		Exh 1, Schedule 1
8		Net Plant in Service	2,451,787,100		264,787,338		2,716,574,439		342,295,185		3,058,869,624		
9		**Working Capital**											
10	154-163-186	Materials and Supplies	1,164,540		21,652		1,186,192		26,703		1,212,895		Exh 108, Schedule 5
11	165	Prepayments	3,475,052		207,145		3,682,197		25,323		3,707,519		Exh 108, Schedule 6
12	164/242	Gas Storage Underground	32,279,714		4,576,069		36,855,783		(2,001,569)		34,854,214		Exh 108, Schedule 7
13		Cash Allowance	0		0		0		0		0		Exh 108, Schedule 4
14		Total Working Capital	36,919,306		4,804,866		41,724,172		(1,949,543)		39,774,628		
15		**Deferred Income Taxes**											
16	190	Income Taxes	74,485,056		(1,186,716)		73,298,340		(3,203,734)		70,094,606		Exh 108, Schedule 8
17	282	Depreciation	(469,366,848)		(12,946,577)		(482,313,425)		(8,881,774)		(491,195,199)		Exh 108, Schedule 8
18	283	Other	0		0		0		0		0		Exh 108, Schedule 8
19		Total Deferred Income Taxes	(394,881,792)	**1/**	(14,133,293)	**1/**	(409,015,085)	**1/**	(12,085,508)	**1/**	(421,100,593)	**1/**	
20													
21	235	**Customer Deposits**	(3,454,041)		(3,952)		(3,457,993)		1,654		(3,456,339)		Exh 108, Schedule 9
22		**Customer Advances for Construction**											
23	252	Cash Deposits	3,034		16,491		19,525		0		19,525		Exh 108, Schedule 10
24		**Total Rate Base**	2,090,373,607	**1/**	255,471,450	**1/**	2,345,845,058	**1/**	328,261,788	**1/**	2,674,106,845	**1/**	

1/ Update filed in N Shultz rebuttal Testimony

Original: Exhibit 108 Schedule 8

COLUMBIA GAS OF PENNSYLVANIA, INC
DEFERRED INCOME TAXES
BALANCE ENDING
December 31, 2022

Line No.	Acct		Pro Forma Balance 11/30/2020 (1)		Pro Forma Balance 11/30/2021 (2)		Pro Forma Balance 12/31/2022 (3)		Reference
1		Account 190 - Deferred Income Taxes							
2	19001000	LIFO Inventory Adj - Federal	6,130,528		6,973,737		6,973,737		
3	19002000	LIFO Inventory Adj - State	3,240,062		3,685,709		3,685,709		
4	19001000	Capitalized Inventory - Fed	960,030		1,015,878		1,015,878		
5	19002000	Capitalized Inventory - St	507,388		536,904		536,904		
6	19005000	Cust. Advances - Fed	726,546		565,678		327,660		
7	19006000	Cust. Advances - St	383,989		298,968		173,172	**1/**	
8	19005000	Federal Net Operating Loss	34,637,164		33,520,471		31,978,769		
9	19005000	Deficient Deferred Taxes 190- NOL, Inventory & Customer Advances	27,899,349		26,700,995		25,402,777		
10		Total Account 190	74,485,056		73,298,340		70,094,606		
11		Account 282 - Deferred Income Taxes-Depreciation							
12	Various	Excess Accelerated Tax Depreciation - Fed							
13		Total Account 282	(469,366,848)	**1/**	(482,313,425)	**1/**	(491,195,199)	**1/**	
			(469,366,848)		(482,313,425)		(491,195,199)		
14		Account 283 - Deferred Income Taxes - Other							
15	28305000	Legal Liability-Lease on G.O. Bldg. - Fed	0		0		0		
16	28306000	Legal Liability-Lease on G.O. Bldg. - St	0		0		0		
17		Total Account 283	0		0		0		
18		Total Accumulated Deferred Taxes	(394,881,792)		(409,015,085)		(421,100,593)		Exhibit 107, Pgs. 5 & 5a

1/ Update filed in N Shultz rebuttal Testimony

R. BRUMLEY

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
RAYMOND A. BRUMLEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

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I. Introduction

Q. Please state your name and business address.

A. My name is Raymond A. Brumley. My business address is 2787 Memorial Boulevard, Connellsville, Pennsylvania 15425.

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

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

Q. Please briefly describe your professional experience.

A. I began my career in 1992 with Columbia, and have held numerous operational positions with increasing responsibilities. From March of 2000 through June of 2002, I was responsible for scheduling work for Columbia Gas of Virginia. I moved into a Field Engineering role in June of 2002 where I designed capital work for the Company and Columbia Gas of Maryland until March of 2011. I then became a leader within the construction department for Columbia, and from there took on roles of increased responsibilities as a Senior Operations Support and Leader Operations Support. In June 2016, I accepted the role of Contractor Performance Manager for the seven states within NiSource. I returned to Pennsylvania and Maryland in November of 2019 as the Manager, Construction Services and currently began my role of Director of Construction on January 1, 2021.

Q. Please describe your educational background.

A. I completed coursework at California University of PA towards a Bachelor's Degree in Business Administration. I received numerous certificates and training opportunities throughout my career.

Q. What are your responsibilities in your current position?

A. My responsibilities include:

- Directing construction operations in executing the delivery of safe, reliable, efficient natural gas distribution service to our customers;
- Assuring construction is in compliance with Federal, State and local regulations as well as in alignment with industry best practices;
- Sponsoring the implementation and execution of capital construction initiatives that build consistency and collaboration across organizations;
- Building and maintaining a network of contract resources that have the capacity and capability to execute on Columbia's capital program.

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

A. Yes. I have testified once before this regulatory agency in a consumer complaint proceeding. I have not testified before any other regulatory agencies.

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

A. I will provide testimony in support of Columbia's plant additions through the Fully Projected Future Test Year (twelve-months ending December 31, 2022) and provide an overview of Columbia's ongoing replacement activities.

II. <u>Columbia's Projected Plant Additions through the FPFTY</u>

Q. Please explain Columbia's capital plant additions related to distribution plant claimed for the Future Test Year and Fully Projected Future Test Year.

A. Columbia plans to maintain or increase its capital expenditures related to distribution plant in the 2021 to 2025 timeframe, with a planned spending program of over $290 million budgeted annually for replacement work, inclusive of mains, services, and measurement and regulation stations, over the 5-year period. This budget includes the following capital budget classes: Age and Condition, Betterment and Public Improvement.

A detailed description of Columbia's Age and Condition actuals for 2020, and the budgeted amount for 2021 and 2022 are provided in the following table.

Table 1

Budget Class - Age and Condition

Gas Plant Account "GPA"	Description	Total 2020 Actual	Total 2021 Projected	Total 2022 Projected
354	Compressor Stations	1,036,577	0	0
376	Mains - Leakage Elimination	159,527,477	176,347,000	200,890,000
380	Service Lines – Replaced	54,198,681	51,143,000	58,349,000
376	Customer Service Lines Replaced	14,441,958	17,048,000	19,450,000
381	Meters / 998 Int. Co. Meters	1,224,509	900,000	950,000
382	Meter Install – Replace	99,006	1,050,000	1,100,000
383	House Regulators - Replace	24,072	70,000	80,000
378	Plant Regulators – Replace	19,659,403	12,810,000	6,820,000
375	Reg Structures Replace	192,860	300,000	300,000
385	LV Excess Press Meas Sta	154,004	900,000	900,000
376	Corrosion Mitigation Ins	128,842	150,000	150,000
383	Service Regulators - Replacement	7,550	20,000	20,000
		250,694,939	260,738,000	289,009,000

The table below (Table 2) depicts the three budget classes, Age and Condition, Betterment, and Public Improvement (rounded to the thousands). Please note – the differences in Age and Condition shown between the two tables are the Shared Service expenditures shared among all NiSource companies. Those Shared Service expenditures are not included in Table 1 above.

Table 2

CPA Budget Class	2020 Actuals	2021 Approved	2022 Projected
Age and Conditon	250,763,000	260,838,000	289,109,000
Betterment	9,743,000	42,615,000	8,500,000
Public Improvement	7,710,000	8,997,000	5,500,000

Q. How does Columbia's actual spend for 2020 compare to the projected budget for 2020 that was provided in the Company's last rate case, filed in 2020?

A. The projected 2020 budget for plant additions related to distribution plant was $250,633,759, which was included in a table similar to the one above on page 15 of Columbia Statement No. 14, in Docket No. R-2020-3018835. The actual spend for 2020 was $250,694,939, so the actual spend was right in line with the projected budget.

Q. Please explain why the 2021 budget is more than the 2020 budget?

A. Within our 2021 Age & Condition budget, Columbia is projecting increases in expenditures for mainline and service line replacement work, primarily due to increased contractor pricing. Also unit costs per foot for mainline replacements and unit costs for service line replacements are expected to increase from 2020 to 2021, as well as 2022, based on additional usage of flaggers and staging vehicles on job sites, beyond what is currently being used. Columbia has experienced an increase in work zone intrusions over the past year, which is a significant safety threat to our employees, our contractors, and the everyday work that we do. This safety initiative, for additional flaggers and staging vehicles at job sites, will help to minimize this growing threat to allow our workforce to concentrate on their tasks at hand and set-up and tear down in a safe and proficient manner.

Within our 2021 Betterment budget, approximately $10 million has been slated for the New Castle odorization project, and $23 million for the Airport/Southern Beltway Corridor modernization project. Within the New Castle operating area, the Company plans to strategically install odorization equipment at certain points of delivery. Columbia is also planning to tie some of its distribution systems together, to more efficiently manage odorization and to enhance safe and reliable service to our customers. The Airport/Southern Beltway Corridor project will involve a modernization of essential infrastructure to boost delivery capability to accommodate industrial manufacturing, commercial and residential markets near the Pittsburgh Airport. The project involves a new point of delivery, two new district regulator stations and a high pressure trunk line.

Q. How was the budget for 2022 developed?

A. In addition to what is stated above, within our 2022 Age & Condition Budget, Columbia is projecting even higher expenditures for mainline and service line replacement work due to our current (5 year) construction blanket contract expiring and a new construction blanket contract taking effect. Though this is competitively bid, based on the market demand for natural gas contractors, not just across

Pennsylvania but other states as well, it is anticipated that their pricing will increase to the levels shown in our 2022 projections. Budget plans are derived based upon historical trends, known future projects, and any commitments made in conjunction with the PA PUC (e.g. over pressure protection program).

III. Columbia's Pipeline Replacement Efforts

Q. How many feet of bare steel, wrought iron, and cast iron main have been eliminated from Columbia's 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 2020, 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	553,765	feet
2012	415,240	feet
2013	452,636	feet
2014	413,667	feet
2015	496,610	feet
2016	478,790	feet
2017	509,428	feet
2018	302,606	feet
2019	516,689	feet
2020	387,821	feet
Total Actual (Through YE 2020)	**6,078,654**	feet

From 2007 through 2020, Columbia's replacement program eliminated an average of 434,190 feet per year. During the four (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. As discussed in witness Kempic's testimony (Columbia Statement No. 1), Columbia was unable to complete all of its projected 2020 replacement work as a result of the COVID-19 Pandemic. Prior to the COVID-19 pandemic, Columbia had 140 crews working on pipeline replacement projects across its service territory. In response to COVID-19, starting March 23, 2020, Columbia took a two week work pause throughout the state where only essential projects were worked. Columbia averaged only 12 crews working during this two week period.

Per the Governor's order, Columbia continued to work only essential projects throughout the month of April, averaging 25 crews. With the release on restrictions starting May 4, 2020, Columbia began to ramp up its crews throughout the month of May, as follows:

May 4th - 49 crews

May 11th - 76 crews

May 18th - 104 crews

By June 8, 2020 Columbia was up to 121 crews and continued to add crews to return to pre COVID-19 levels. It should be noted that not all crews were able to return for various reasons as a result of COVID-19. Some contractor employees were laid off during the work pause.

Q. Why does Columbia need to continue to replace its bare steel and cast iron systems?

A. Columbia's Distribution Integrity Management Program ("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 approximately 49% of all hazardous or potentially hazardous leakage cleared on mains in the Columbia distribution system as of year ending 2020. 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.

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, some 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. If left unchecked, 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 and described in Columbia witness C.J. Anstead's testimony (Columbia Statement No. 14) 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. 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. Additionally, "first generation" plastic pipe has demonstrated itself to be prone to stress propagation cracking under some circumstances due to the different composition of the base plastic material.

With all of that stated, 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), also necessitate a measured replacement strategy geared to those locations where Columbia is uncovering this pipe in the course of replacing other facilities. Witness Anstead provides further testimony on the Company's plans with respect to replacement of unprotected coated steel and first generation plastic pipe.

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 we 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 upstream 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 ("EFVs") on nearly all services connected to the replaced mains.[1] The EFVs 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.

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[1] An exception may be granted to installing an EFV on multifamily residences and non-residential (e.g. commercial, industrial) service types by a Field Engineering Manager when the known customer load at the time of installation is 1,000 cubic feet per hour ("CFH") or greater. If an exception is granted, a curb valve shall be installed in accordance with the applicable Columbia Gas Standard (GS 3020.020 "Service Lines Valves Requirements and Locations") and also documented on the service line record as to why an EFV was not installed. Note EFVs are currently available up to 10,000 CFH capacity. This means that for the majority of new and replaced service lines on systems with an MAOP greater than 10 psig, the service line will have an EFV installed.

Q. How will main replacements affect the Company's leak repair experience?

A. The long term view is that as bare steel, wrought iron, and cast iron pipe is removed from the system, we expect to see a reduction in Type 1 and Type 2 leakage repair caused by corrosion. However, this impact is expected to be gradual over the period of the program. The remaining cast iron, wrought iron, and bare steel pipe to be replaced continues to degrade, which continues to drive Type 1 and Type 2 leakage repair activities. In 2020, 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 388, a 90% 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, durable 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 2017-2018 winter heating season, as well as this past 2021 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 coordinators and construction specialists), 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, on average during 2020 Columbia had approximately 113 construction crews (2020 average is down due to COVID) which employed approximately 1,130 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.). For 2021, Columbia will have approximately 145 construction crews with approximately 1,450 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.).

Q. Is there anything else that you would like to say about Columbia's pipeline replacement efforts?

Yes. 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 Columbia witness Anstead's 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 15 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.

IV. Replacement Costs & Restoration Issues

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 2020 actuals, is $227.00 per foot. 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 that 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 experience 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, ten 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 natural gas distribution companies ("NGDCs") in Pennsylvania and across the country undertake main replacement programs, increase training and qualification requirements, and fight for the availability of construction work with other businesses inside and outside of the industry.

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 six gas 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 will describe later in my testimony. Columbia's service territory spans over 450 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.

Since November of 2020, we have added nine Construction Project Management positions across the state to provide more project management rigor to our larger, more complex projects. The responsibilities of these positions include but are not limited to assisting in the project design, permitting process, job readiness, maintaining job scope, costs, safety, productivity, and constant communication with internal and external stakeholders. They will maintain a working relationship with municipal leaders during the job while delivering job updates.

Q. Do municipal standards continue to impact Columbia's aggressive pipeline replacement program?

A. Yes. Columbia serves approximately 436,000 customers within 26 counties and roughly 450 municipalities throughout the Commonwealth. Because of the size of our footprint, the number of municipalities we operate in and the lack of standard ordinances and restoration requirements across those communities, as a Company, we continue to face challenges related to local municipal oversight, fees, permitting processes and project restoration requirements related to our pipeline replacement program. Local municipalities struggling with budgetary issues continue to look to shift costs and road maintenance responsibilities to utilities working (cutting into their streets) in their communities. Increased local municipal requirements or fees have and will continue to delay our pipeline replacement work and new business efforts, as well as cost the Company and our customers' additional money.

Q. What is Columbia's plan to address these ongoing municipal challenges?

A. Columbia continues to implement a comprehensive plan to address municipal issues. The Company's Communications, Municipal Affairs and Community Relations team (in addition to select local operations, construction, engineering and new business employees) developed and executed a proactive municipal outreach program to establish, improve and maintain relationships with municipal officials in communities where we are, and will be, conducting significant pipeline replacement or new business projects. The program continues to focus on educating identified local staff/officials and elected representatives of boroughs, townships and cities/towns about:

- Columbia
- Our pipeline replacement and new business efforts in general.
- Specific planned pipeline replacement or new business projects in their

community.

- The benefits of our pipeline replacement or new business projects in their community.
- The need for reasonable permit fees and restoration requirements.

In addition, most recently, Columbia hired two new Public Affairs Specialists to work with its Manager of Municipal Affairs to work directly with municipalities to review proposed or passed local public policies that may impact Columbia's proposed work. Specifically, the Public Affairs team is tasked with monitoring municipal ordinances and proposed amendments that may unreasonably increase paving restoration requirements, unreasonably increase permitting fees or place additional unreasonable fees for inspections, road openings or road degradation on Columbia's work.

Q. Please provide further detail on the outreach focus of the municipal outreach program.

A. The outreach program focuses on, but is not limited to, the following groups:

- Local boroughs, townships and cities/towns in which we have not replaced significant mainline pipe or had new business projects, but have planned projects in 2021.
- Local boroughs, townships and cities/towns in which we need to improve and enhance relationships due to past issues or new ordinances adversely affecting our operations or our customers.
- The district offices and staff of identified state legislators to educate them on planned pipeline replacement/new business projects in their district and to

gain a better understanding about local governments and their leadership. These offices may also be able to assist Columbia with relationship building and communications with local governments when appropriate.

Q. Do you have some examples of how Columbia was proactively engaged in addressing municipal issues in the most recent calendar year, 2020?

A. Yes. In 2020, the Communications, Municipal Affairs and Community Relations team participated in the following discussions:

- **Allegheny County - CONNECT Utilities Meetings:** Columbia participated virtually in CONNECT Spring and Fall Utilities Meetings, which brought together numerous municipalities and utility representatives to discuss planned utility projects and municipal government paving plans.
- **Allegheny County - City of Pittsburgh Utility Coordination:** Throughout the year, Columbia participated with the City of Pittsburgh in its monthly utility coordination meetings to coordinate utility projects with road restoration and repaving efforts. In addition, Columbia and other utilities met with the Mayor's Chief of Staff early in 2020 to discuss improved utility coordination.
- **Allegheny County –** Columbia hosted proactive meetings or discussions with Baldwin Borough, Bellevue Borough, Findlay Township, Mt. Lebanon Township, Peters Township, Pleasant Hills Township, Scott Township, South Fayette Township and Whitehall Borough regarding 2020 pipeline replacement projects or operational work in those communities.
- **Beaver County –** Columbia hosted proactive meetings or discussions with

Beaver Borough and Franklin Township on proposed pipeline replacement projects.

- **Centre County –** Columbia hosted proactive meetings with State College Borough regarding operational work and planned pipeline replacement projects in addition to the borough's permit process and expectations.
- **Fayette County –** Columbia hosted proactive meetings with Springhill Township and Stockdale Borough on pipeline replacement projects.
- **Lawrence County –** Columbia hosted proactive meetings with Wampum Borough on a pipeline replacement project and permitting in the borough's right-of-way.
- **Washington County –** Columbia hosted proactive meetings with Canonsburg Borough to discuss paving restoration concerns and East Washington Borough regarding a pipeline replacement project, permitting and reasonable restoration requirements.
- **Cross Creek Township, Washington County:** Columbia met with township officials to discuss the PA One Call law, Commission enforcement and the AVR (alleged violation report) process. The township was upset it had been cited for PA One Call law violations outside its municipal boundaries. Columbia explained the law, how it works and what is required and worked with the township and the PA One Call Board to address concerns about compliance with the PA One Call law.
- **Westmoreland County –** Columbia hosted discussions with the City of Jeannette regarding restoration requirements for operational work in the

City.

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. Outside of the examples provided above, has Columbia been successful in challenging restoration requirements that Columbia considers to be atypical?

A. Yes. Some examples of Columbia's success are as follows:

- **City of Pittsburgh, Bon Air Neighborhood, Allegheny County:** Columbia was in regular contact with City of Pittsburgh officials regarding issues and concerns with the restoration of streets and property associated with the infrastructure replacement projects completed in the Bon Air neighborhood. Columbia was able to reach a co-op agreement with the City on the paving of streets in the neighborhoods and completed the majority of the restoration work by the end of 2019.

- **Beaver Borough, Beaver County:** Columbia conducted several meetings with Beaver Borough officials in late 2018 and 2019 to reach an agreement with Beaver Borough officials to share restoration costs for roadway and sidewalk restorations associated with Columbia's 2019 pipeline replacement projects. These meetings led to an agreement on planned work for 2020, including enhanced communications to affected Beaver Borough residents about the projects.
- **Harmony Township, Beaver County:** Columbia met with the township manager and public works director to discuss 2019 projects and planned restoration work. Columbia was involved in a lengthy dispute with the township over street opening fees and restoration costs that was eventually settled. For the 2019 projects, Columbia and the township reached a settlement on fees and restoration plans, and the process went smoothly throughout the infrastructure replacement project in 2019.
- **City of Bradford, McKean County:** Columbia met with City of Bradford officials in early 2019 to address concerns about 2018 restorations and Columbia's planned work in 2019. The group was able to successfully address concerns about past restorations and reached an agreement on coordination

of Columbia's work with the City's planned sidewalk improvement plans for 2019.

- **City of Pittsburgh, Allegheny County:** In the Spring of 2020, the City undertook a comprehensive rewrite of its permit policies and procedures related to work in their right-of-way. Columbia worked with the City to explain our concerns with newly proposed rules that were not within the jurisdiction/oversight of local governments and a new permitting fee based on the size of a project and time it took to complete. At the urging of Columbia and other utilities, the City adjusted its policies related to oversight of Commission regulated utilities and capped the permit fee costs related to large projects.
- **Brownsville Borough, Fayette County:** Columbia continued to work with Borough Council in 2020 regarding its concerns with updated permit fee formulas and restoration standards that would increase costs for work Columbia conducts in the borough. Borough Council has agreed to review the issue and Columbia provided the borough with examples of reasonable permit fee and restoration ordinances in other nearby municipalities.
- **Georges Township, Fayette County:** Columbia has engaged the township's supervisors in opposition to the implementation of an engineering inspection fee based on the square yardage of the road disturbance created by Columbia's work in the right of way. This fee language was included in an update of the township's road cut ordinance. When seeking a permit to replace 5,500 feet of mainline pipe in 2020, the

township's engineering firm informed Columbia the engineering inspection fees were estimated to be between $82,000 and $85,000 for the project. Columbia has objected to those fees.

- **Luzerne Township, Fayette County:** Columbia met with the Luzerne Township Supervisors to discuss a proposed permit fee formula change/increase and increased restoration standards. After discussion with the Supervisors, the changes/increases were placed on hold.
- **Rices Landing Borough, Greene County:** Columbia worked with the Mayor and Borough Council to prevent the retroactive application of increased permit fee costs in a new road opening ordinance passed by the Council in 2020. Columbia also expressed concerns with a new "escrow account fee" for new permit requests mandated in the new ordinance. The "escrow fee" language provides few details on what may be charged by the borough against this account. Columbia is monitoring its application to ensure unreasonable charges are not applied against the escrow account.
- **Canton Township, Washington County:** Columbia continues to oppose the township's policy of requiring the signing of a "Road Maintenance Agreement" which forces significant paving restoration (100 yards) on each side of a road opening cut Columbia may make. In 2020, Columbia negotiated a restoration agreement using PennDOT restoration standards for both a 2020 and 2021 pipeline replacement project reducing restoration costs on the project.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 7-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
RAYMOND A. BRUMLEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

Q. Please state your name and business address.

A. My name is Raymond A. Brumley. My business address is 2787 Memorial Boulevard, Connellsville, PA 15425.

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

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

Q. Have you previously filed testimony in this matter?

A. Yes, I submitted Direct Testimony as part of the Company's rate case filing made on March 30, 2021.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to OCA witness David Effron's adjustment to the Company's forecasted plant additions for the years 2021 and 2022, which are the Future Test Year ("FTY") and Fully Projected Future Test Year ("FPFTY"), respectively.

Q. What does Mr. Effron recommend with regard to Columbia's forecasted plant additions in 2021 and 2022?

A. Witness Effron recommends adjusting the Company's 2021 and 2022 forecasted plant additions used to calculate the Company's projected 2022 rate base, stating on page 5 of his testimony that he does so because the Company's "forecasted plant additions for both 2021 and 2022 are well in excess of the actual plant additions in recent years."

Q. How does Mr. Effron arrive at his adjustment and what is the result?

A. Mr. Effron averages the net plant additions for the years 2019 and 2020 to determine that the Company's plant additions for 2021 and 2022 should be approximately

$286,203,000 million (with corresponding adjustments to depreciation reserve and accumulated deferred income taxes), instead of the Company's projected plant additions for the years 2021 and 2022, as provided in Company witness Shultz's Exhibit 108.

Q. Do you agree with Mr. Effron's recommended adjustment?

A. No I do not agree. Mr. Effron's adjustment to Columbia's 2021 and 2022 plant additions is based on the fact that the 2021 and 2022 forecasted additions exceed the Company's plant additions in the years 2019 and 2020. He does not, however, state that the forecasted plant additions themselves are unnecessary or unreasonable. Mr. Effron's adjustment also ignores the fact that Columbia's forecasted plant additions include defined, planned projects that have either already begun in 2021 or are ready for execution in 2022. Further, Mr. Effron's proposed adjustment fails to acknowledge that Columbia has a good track record of accurately projecting plant additions and executing its capital projects.

Q. Please explain why the forecasted plant additions are necessary and reasonable.

A. The Company's forecasted plant additions are necessary and reasonable because they directly relate to maintaining the safety and reliability of Columbia's natural gas distribution system. Providing safe and reliable service includes the Company's commitment to the replacement of aging infrastructure on its gas distribution system. Mr. Effron's recommendation suggests that just because the forecasted plant additions for 2021 and 2022 are more than the forecasted plant additions for the past two years that they should be adjusted downward. What Mr. Effron fails to acknowledge is that Columbia continues to replace its aging infrastructure as it has committed to do so as stated in the Company's Long Term Infrastructure Improvement Plan ("LTIIP"). The large majority of the plant additions over the next two years, approximately $549.9 million, is in age and condition spend, which is related to the Company's infrastructure replacement program.

In addition, as noted by Mr. Effron on page 5 of his direct testimony, the increase in forecasted plant additions from 2020 to 2021 includes an increase in spending in the betterment category. Betterment is part of the Company's LTIIP, and as explained on page 5 of my direct testimony, approximately $10 million is associated with the New Castle odorization project, and $23 million is for the Airport/Southern Beltway Corridor modernization project. These two projects represent approximately $33 Million of $49 Million adjustment proposed by Mr. Effron for 2021. Most of the remainder is due to an approximate $10 Million, or 4%, increase to age and condition spend in 2021 compared to actual 2020 age and condition spend, as shown on page 4 of my direct testimony.

The Company's FPFTY capital budget also includes small amounts for growth, public improvements and support services, which are normal investments associated with new construction, required facility relocations and Information Technology. The Company's 2021 and 2022 plant additions in the amount of approximately $356.1 million and $342.9 million, respectively, should be approved because they include spend that is directly related to maintaining the safety and reliability of Columbia's system, they align with the Company's LTIIP commitments and they include additions for planned projects which the Company began to execute in 2021.

Mr. Effron's adjustments would jeopardize the Company's ability to maintain a safe and reliable system and jeopardize the Company's ability to meet its LTIIP commitments. In sum, Mr. Effron's recommendation to adjust the Company's 2021 and 2022 plant addition spend downward is inappropriate and should be rejected.

Q. If a project comes in under budget, does that mean that Columbia will not meet its capital spending projections?

A. It does not, for several reasons. While Columbia uses available information and historic experience to make projections for project costs, actual project costs can come in both over and under budget. Therefore, underspending on one project will be used for projects that are over budget. Second, as explained in the direct testimony of Columbia witness Anstead, the Company still has substantial footage of priority pipe to replace. If spending is coming in under budget, the Company can schedule additional projects to replace additional priority pipe.

Q. Earlier in your Rebuttal Testimony you state that Mr. Effron's adjustment to Columbia's forecasted plant additions does not consider the fact that the Company's forecast includes defined, planned projects that have either begun or are ready to be executed in 2021 and 2022. Please explain this statement.

A. Witness Effron's proposal to use a two-year historic average for plant additions in the FTY and FPFTY instead of the Company's forecasted plant additions included in Schedule 108 ignores that Columbia's plant addition forecasts were driven by the actual work that the Company plans to execute in 2021 and 2022, and that the Company is in the process of executing these planned projects. Further, each of the planned construction projects include unique issues, such as locational factors and increases to costs outside of the Company's control, such as increased contractor pricing, but budgeting construction work using a historic average does not take these project-specific cost issues into consideration.

Q. Please describe the planned projects that Columbia has undertaken in 2021.

A. My Direct Testimony specifically mentions the New Castle odorization project and the Airport/Southern Beltway Corridor project, so I will start with those two projects.

Regarding the New Castle odorization project, the work will be dispersed between 2021 and 2022. In 2021, 4 stations are looking to be equipped with odorization: designs are complete, materials have been ordered, contracts are in place, and work is to commence in mid August. The remaining 6 stations are slated for 2022 construction: design work is still being worked on and finalized. Also in conjunction with this odorization project, some mainline installation will be installed. Much of the design and permitting for this mainline installment will be done in 2021, with the actual work to commence spring of 2022.

Regarding the Airport/Southern Beltway Corridor project, the Southern Beltway project is designed to provide gas service for the Maronda Homes Abbey Residential Housing Plan. This development consists of approximately 1,000 homes. Approximately 15,000 feet of new 12-inch plastic pipe will be installed along with a new Point of Delivery (POD) Station with National Fuel Gas, and a new district regulation station, which will provide a backup feed to an existing

Columbia of PA distribution system. The pipeline portion is currently under construction and approximately 70% complete. The new district regulation station is currently under construction and will be completed by the end of July. The new POD will be installed during August. Restoration is slated to begin July 9th, and is scheduled for completion by the end of August. Project completion with gas flowing is scheduled for the end of October 2021.

In addition to those two projects, the Company has also executed on a number of other projects. To date, Columbia has installed approximately 66 miles of replacement pipe, and has abandoned over 22 miles of priority pipe. Abandoned mileage (which simply is the pipe permanently removed from service) lags behind the install mileage because it is the last step in the process. It is not unusual to have the majority of our priority pipe abandoned in the latter half of the year. Columbia is on target to achieve its goal for 2021.

Q, Mr Effron also has questioned the validity of the Company projections, on the basis that a large proportion of the net additions are projected for the 4th quarter of the year. Would you please comment.

A. There can be several reasons for this. First, a portion of the New Castle odorization project and the Airport/Southern Beltway Corridor project referenced above are not scheduled to be completed until later this year. Second, the timing of when projects are closed to plant in service can lag behind the completion of construction. This is because projects are not closed out to plant in service until all invoices have been received.

Q. Please describe the projects that Columbia has planned for 2022.

A. As Mr. Effron notes in his testimony, the increase in 2022 relates primarily to plant additions related to age and condition. Columbia has an array of projects being planned for 2022. Many of these projects are in the design phase, and work on land acquisition and permitting for environmental and governmental permits is in progress so that the projects are "shovel ready" for the start of 2022. As in previous years, Columbia will produce a listing (proposed projects for 2022) as part of Columbia's Annual Asset Optimization Plan filing, along with projects that have been completed the previous year (i.e., 2021). Proposed projects for 2022, like that of 2021 and previous years, are dynamic and are subject to modification based on emerging conditions. The roster, once fully established, will be supplemented throughout the calendar year of 2022 to reflect the continued assessment of system conditions. Anticipated increases in 2022 expenditures have been outlined in my direct testimony, page 5, lines 18-23, and page 6, lines 1-4.

Q. Please explain how Columbia can develop a budget for 2022 if the project roster for 2022 is subject to change.

A. Budgets are established based on historical trends, anticipated costs *and* known upcoming projects (e.g. a municipality may be doing a streetscape where priority pipe exists, or the state may be doing work in which we may have to relocate). Once Columbia's budgets have been approved, it is imperative to have the flexibility internally to shift dollars to various projects based on emerging conditions. When planning construction projects, it is critical to keep the project roster flexible so that if conditions on the ground change, the Company can alter its work, even if that means shifting the timing and/or scope of other projects.

Q. Earlier in your Rebuttal Testimony you stated that Mr. Effron's proposed adjustment fails to acknowledge that Columbia has a good track record of accurately projecting plant additions and executing its capital projects. Please explain this statement.

A. Witness Effron's proposed adjustment seems to be based on a position that the Company's forecasted plant additions are inherently flawed because the Company's projections do not match the level of plant additions made by the Company in recent years. This statement lacks any basis. Columbia's capital program is not driven by the level of plant additions made in the past, but instead, the Company's capital plan is driven by the need for the replacement of priority pipe. Columbia will continue to accelerate the replacement of priority pipe as long as there is a need to reduce risk by replacing pipe that is nearing the end of its useful life. This is consistent with the goals of the Company's Long Term Infrastructure Improvement Plan that has been approved by the Commission.

Q. Are there any other issues that you want to address?

A. I note that Columbia witness Nicole Paloney, in Columbia Statement No. 9-R, explains why Mr. Effron's claim that reducing the balance of plant in service in the FPFTY does not impose a risk of under-recovery for the Company is inaccurate.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

P. MOUL

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-2021-3024296

March 30, 2021

Columbia Gas of Pennsylvania, Inc.
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
FPFTY	Fully Projected Future Test Year
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Companies
Lev	Leverage modification
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
s x v	Represents external growth

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
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, it is my opinion that the rate of return on common equity should be set at 10.95%. Although my 10.95% return on equity does not make a specific provision for management effectiveness, the testimony of witness Mark Kempic, President of the Company (Columbia Statement No. 1) describes the superior performance of its management. Witness Kempic has shown that the Company ranks high in customer service and management efficiency. My cost of equity determination should be viewed in the context of the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. 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, 2022 Fully Projected Future Test Year ("FPFTY"). The Company's proposed rate of return is shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	41.77%	4.54%	1.90%
Short-Term Debt	3.89%	0.85%	0.03%
Total Debt	45.66%		1.93%
Common Equity	54.34%	10.95%	5.95%
Total	100.00%		7.88%

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. Are there unusual factors that you included in your analysis of the cost of equity for CPA that make this case unique?

A. Yes. My cost of equity analysis reflects the impact of the coronavirus pandemic. This event had a significant impact on the capital markets -- both debt and equity. Extraordinary events around the COVID-19 pandemic have produced significant turmoil that has rocked the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As a recession began in February 2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. That is to say, I have considered these events as they impact the inputs that I used in the various models of the cost of equity. I have applied the cost of equity models using input data that follows the beginning of the economic recession.

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), and other energy investments.

The Company provides natural gas distribution service to approximately 436,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended December 31, 2019 was represented by approximately 46% to sales customers and approximately 54% 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 10.95%.

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 nine (9) gas companies. I will refer to these companies as the "Gas Group" throughout my testimony. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of ten companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and gas generation. The companies in the Gas Group are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity

[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).

models in the recent Quarterly Earnings Report (Docket No. M-2020-3023406) approved by the Commission on January 14, 2021.

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.

	Gas Group
DCF	13.46%
Risk Premium	10.00%
CAPM	12.67%
Comparable Earnings	12.00%

From these measures, I recommend a cost of equity of 10.95%. My equity return of 10.95% is amply supported by the market models (i.e., DCF, Risk Premium and CAPM) whose results are in the range of 10.00% to 13.46%. 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 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 witness Kempic and other Company witnesses discuss the investments that the Company has made and 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. Notably, one customer departed the Company's system in the Spring 2019 and switched to another LDC that provides service in an overlapping service territory to the Company. This clearly demonstrated the high risk faced by the Company to bypass. 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, especially with 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. I also understand that the Company is proposing a second mechanism, called a RNA, that is a revenue normalization adjustment mechanism applicable only to residential customers. Description of the Company's RNA is contained in the testimony of Company witness Notestone.

Q. Does your cost of equity analysis and recommendation take into account the WNA that the Company has?

A. Yes. All of my Gas Group companies have some form of WNA mechanism, and in some cases, other forms of revenue decoupling. Therefore, the market prices of all companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a normalization mechanism. Therefore, my analysis reflects the impacts of normalization adjustment mechanisms on investor expectations through the use of market-determined models. If the Company is unable to obtain the RNA mechanism, 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 Distribution System Improvement Charge ("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 short periods of time in the past. The cost of capital for CPA, however, is not affected by the DSIC. I say this because all of the proxy group companies whose data has been used to develop the cost of equity for CPA in this proceeding have at least some form 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 bypass threat posed to 66 of the Company's major account customers, i.e., those with large volume usage and/or those with competitive alternatives. This throughput to these 66 customers represents approximately 24% (18,568,998 Dth ÷ 78,965,406 Dth) of the Company's total throughput. 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.

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, and/or nonregulated pipeline contractors providing access to local supplies. This was the risk to the Company noted above. Third, in addition to the bypass threat, a material portion of the large customer throughput can be exposed to alternative 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 1181.2 miles (or approximately 15%) of its distribution mains as of year-end 2019. The Company also has 42,695 (or approximately 10%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2021	$ 388,813,000
2022	$ 370,256,000
2023	$ 423,110,000
2024	$ 433,468,000
2025	$ 451,959,000
Total	$ 2,067,606,000

The Company's total capital expenditures over the next five years will represent approximately 82% ($2,067,606,000 ÷ $2,533,660,000) of the net utility plant in service at December 31, 2020.

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 dividend payments in any of the years 2014 through 2020. 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, New Jersey Resources Corp., NiSource Inc., Northwest Natural Holding Co., ONE Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, and Spire, 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 from NiSource Inc. 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 2015-2019. 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 slightly higher for the Gas Group compared 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 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 55.1% for CPA, 52.6% for the Gas Group, and 42.2% for the S&P Public Utilities. The Company's common equity ratio was fairly similar to the Gas Group, thereby indicating similar financial risk.

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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).

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 0.119 (1.3% ÷ 10.9%) for the Company, 0.089 (0.8% ÷ 9.0%) for the Gas Group, and 0.049 (0.5% ÷ 10.2%) 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 74.3% for the Company, 84.1% for the Gas Group, and 78.8% for the S&P Public Utilities. The Company's operating ratios were 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 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 4.43 times for the Company, 4.23 times for the Gas Group, and 3.22 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk.

[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.

<u>Quality of Earnings.</u> 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. In 2018 and 2019, the effective income tax rate declined from earlier years after implementation of the TCJA.

<u>Internally Generated Funds.</u> 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 64.5% for the Company, 59.5% for the Gas Group and 74.1% for the S&P Public Utilities. Had the Company paid dividends in recent years, its IGF would have been weaker. The Company's average IGF to construction percentage has been slightly stronger than the Gas Group, which can be traced to the lack of dividend payments by the Company. The IGF to construction has declined for the Gas Group in 2018 and 2019 with the implementation of the new lower federal income tax rate because of lower marginal rates and lower provision for deferred income taxes. The Company has not been similarly affected because in 2018 and 2019 its revenues increased, while operating expenses decreased, which more than offset the decline in income taxes, including tax deferrals. The Company's IGF to construction expenditures will be under pressure in future years as its construction expenditures will increase.

<u>Betas.</u> 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 0.87 as the average for the Gas Group (see page 2 of Schedule 3) and 0.91 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. Please summarize your risk evaluation.

A. In several aspects, principally related to its smaller size, its more variable equity returns, competitive pressures, and new capital needs to fund construction, CPA's risk is higher than the Gas Group. Its operating ratios indicate lower risk for CPA. Its common equity ratio, interest coverage, quality of earnings, and IGF to construction, point to similar risk for CPA and the Gas Group. On balance, the cost of equity measured with the Gas Group data will provide a reasonable representation 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. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed.

Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

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[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.

A. Yes. Schedule 5 presents the Company's capitalization and related capital structure ratios. The November 30, 2020 capitalization corresponds with the end of the HTY in this case. The November 30, 2021 capital structure is estimated at the end of the FTY, and the December 31, 2022 capital structure is estimated at the end of the FPFTY. The Company will receive equity infusions of $60 million in the FTY and $5 million in the FPFTY. The Company expects to issue $110 million of new long-term debt in the FTY and $125 million of new long-term debt in the FPFTY. A projection on retained earnings has been reflected in the FTY and FPFTY including an assumption of no dividend payments in either case.

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 FPFTY. As a result, I will adopt the Company's FPFTY capital structure ratios of 41.77% long-term debt, 3.89% short-term debt, and 54.34% common equity at December 31, 2022. For short-term debt, I have used a twelve-month average for the FPFTY. 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.

Costs of Senior Capital

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, 2020. On page 2 of

Schedule 6, I have shown the embedded cost rate of debt estimated at November 30, 2021. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2022. For the new issues of long-term debt, I have used a cost of 3.25% for the issue in the FTY and 3.67% for the issue in the FPFTY. In each instance, the interest costs were determined from the Bloomberg forward yield curve on 30-year Treasury bonds plus the spread that represents the NiSource credit quality of BBB+.

I will adopt the 4.54% embedded cost of long-term debt at December 31, 2021, 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 41.77% 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 0.85%, which represents the Company's estimate for the FPFTY. The Company obtains its short-term debt from the NiSource money pool, which has as its source commercial paper. The interest rate for this case is established as the forecast of the 3-month LIBOR rate, plus an additional 0.30%, which reflects the recent historical yield differential between the 3-month LIBOR rate and NiSource's commercial paper borrowing rate.

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 4.23% for the FPFTY.

<u>Cost of Equity – General Approach</u>

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among CPA, the 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 10.95% for CPA.

Discounted Cash Flow

Q. Please describe the Discounted Cash Flow model.

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-determined 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, which assumes that 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 Schedule 1, page 2, for the Gas Group. The DCF return is 13.46% with the leverage adjustment and 11.29% without the leverage adjustment for the Gas Group.

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. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. 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 2020, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted 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 2020 the average dividend yield was 3.36% for the Gas Group based upon a calculation using annualized dividend payments

[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.

and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.65% for both periods. For applying the DCF model, I have used the six-month average dividend yield of 3.65% for the Gas Group. The use of this dividend yield will reflect current capital 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 investors' anticipated cash flows. 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 fourteen basis points to the six-month average historical yield, thus producing the 3.79% adjusted dividend yield for the Gas Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses 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 stabilize 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. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts, which are those used by investors when pricing common stocks.

Q. How did you determine an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. 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. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth 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, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides those data. While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. 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 investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. 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 investors' expectations of their actual total return. Moreover, academic research focuses also on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call, and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. 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, and Zacks 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 for the Gas Group are also included on Schedule 9.

Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (6.83%), Zacks (9.16%), and Value Line (9.89%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. 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 fact, Professor Myron Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[6] Consistent with Professor Gordon's findings, projections of

[6] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 6.83% to 9.89%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 7.50% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates and is below the midpoint of that data set. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average market capital structure ratios are 33.04% long-term debt, 0.00% preferred stock, and 66.96% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. 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 from the capital structure 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-valued capitalization of a firm. If the rate setting 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 rate-setting process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's 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 8.91% 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 the book value of equity that differs from their cost of equity determined from stock market prices. 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. 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 actually existed.

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: 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. What I label 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) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I expressed my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and 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 8.91%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 4.55% to compensate investors for the risk of a 48.57% debt ratio. Under this approach, the parts sum to 13.46% (8.91% + 4.55%), 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 3.79% dividend yield, the 7.50% growth rate, and 2.17% for the leverage adjustment in order to arrive at the same 13.46% (3.79% + 7.50% + 2.17%) return. I know of no means to mathematically solve for the 2.17% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 2.17% adjustment is merely a convenient way to compare the 13.46% return computed using the Modigliani & Miller formulas to the 11.29% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule 7, page 1) based on a market-value capital structure. A

11.29% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. 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 rate-setting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 13.46%, computed as follows:

	D_1/P_0	+	*g*	+	*lev.*	=	*K*
Gas Group	3.79%	+	7.50%	+	2.17%	=	13.46%

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 the results of other models when determining a company's cost of equity.

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 Schedule 1, page 2. That result is 10.00%.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 3.25% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data are 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 Schedule 11, page 1. For the twelve months ended December 2020, the average monthly yield on Moody's index of A-rated public utility bonds was 3.02%. For the six and three-month periods ended December 2020, the yields were 2.81% and 2.86%, respectively. During the twelve-months ended December 2020, the range of the yields on A-rated public utility bonds was 2.73% to 3.50%. Page 2 of Schedule 11 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 1.45% on a twelve-month average basis, 1.32% on a six-month average basis, and 1.24% on a three-month average basis. Giving greater emphasis to the three-month average spread, which reflects the downtrend, 1.25% represents a reasonable 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. 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, 2021, 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
2021	First	2.5%	3.5%	1.7%	1.25%	2.95%
2021	Second	2.5%	3.6%	1.8%	1.25%	3.05%
2021	Third	2.6%	3.7%	1.9%	1.25%	3.15%
2021	Fourth	2.7%	3.8%	2.0%	1.25%	3.25%
2022	First	2.8%	3.8%	2.1%	1.25%	3.35%
2022	Second	2.8%	3.8%	2.1%	1.25%	3.35%

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, 2020 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
2022-2026	3.6%	4.6%	2.8%
2027-2031	4.5%	5.4%	3.6%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.25% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon those data to make investment decisions.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2020 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. 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 Schedule 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.70%
Average Across All Interest Rates	5.69%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.70% when the marginal cost of long-term government bonds was low (i.e., 2.88%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.69% when the average government bond yield was 4.99%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

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 10.00%, computed as follows:

	i	+	*RP*	=	*k*
Gas Group	3.25%	+	6.75%	=	10.00%

Capital Asset Pricing Model

Q. How is the CAPM used to measure the cost of equity?

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 12.67% for the Gas Group. 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 0.87 for the Gas Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the rate-setting 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 re-leveraged for the book value common equity ratios using the Hamada formula,[7] as follows:

$$\beta l = \beta u \, [1 + (1 - t)\, D/E + P/E]$$

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[7] 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.

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 0.63 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 1.10 for the book value capital structure of 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 2020, the average yield on 30-year Treasury bonds was 1.56%. For the six- and three-months ended December 2020, the yields on 30-year Treasury bonds were 1.49% and 1.62%, respectively. During the twelve-months ended December 2020, the range of the yields on 30-year Treasury bonds was 1.27% to 2.22%. The low yields that existed during recent periods can be traced to weakness in business fixed investment and exports due in part to the U.S.'s trade war with China. Thereafter, extraordinary events associated with the COVID-19 pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and significant declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, a historic rout in stock prices took place and the Federal Open Market Committee ("FOMC") acted to address these disruptions. Presently, the Fed Funds rate is near zero. The

FOMC continues to support the money and capital markets during the coronavirus pandemic.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2021 indicate that the yields on long-term Treasury bonds are expected to be in the range of 1.7% to 2.1% during the next six quarters. The forecast for the FPFTY is 2.1% for 30-year Treasury Bonds. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 2.8% from 2022 through 2026 and 3.6% from 2027 to 2031. 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 2.00% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on Schedule 13, page 2 the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 11.92% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.88% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 11.92% and the average yield on long-term government bonds of 2.88%. The resulting market premium is 9.04% (11.92% - 2.88%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 10.50% total market return. With this forecast, I calculated a market premium of 8.50% (10.50% - 2.00%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 8.77% (8.50% + 9.04% = 17.54% ÷ 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. 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) had returns in excess of those shown by the simple CAPM. As noted previously, CPA is relatively smaller than the Gas Group. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation.

Q. What does your CAPM analysis show?

A. Using the 2.00% risk-free rate of return, the leverage adjusted beta of 1.10 for the Gas Group, the 8.77% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	**=**	***k***
Gas Group	2.00%	+	1.10	x (	8.77%	) +	1.02%	=	12.67%

<u>Comparable Earnings Approach</u>

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks characteristics would need to realize in order to compete for capital. 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 investor expectations for public utility returns. 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. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies 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 Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because they provide 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 Schedule 14, page 2, 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 did you consider in your Comparable Earnings analysis?

A. I 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 11.9% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 12.1% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data my Comparable Earnings result is 12.00%, as shown on Schedule 1, page 2.

Conclusion On Cost Of Equity

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.95% for CPA. My cost of equity recommendation is within the range of results and should be considered in the context of the Company's risk characteristics relative to the barometer group companies. 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. In summary, the Company should be provided an opportunity to realize an 10.95% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, and sustain its cash flow in the context of the its high levels of capital expenditures.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

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 rebuttal testimony.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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 300 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).

Statement No. 8-R

COLUMBIA GAS OF PENNSYLVANIA, INC.

Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

Docket No. R-2021-3024296

July 14, 2021

Introduction and Purpose of Testimony

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.

Q. Did you previously submit testimony in this proceeding on behalf of Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company")?

A. Yes. I submitted my direct testimony, CPA Statement No. 8, on March 20, 2021.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted by Kevin W. O'Donnell, a witness appearing on behalf of the Office of the Consumer Advocate ("OCA") (OCA Statement No. 2), Christopher Keller, a witness appearing on behalf of the Commission's Bureau of Investigation and Enforcement ("I&E") (I&E Statement No. 2), and Mr. James L. Crist, a witness appearing on behalf of Pennsylvania State University ("PSU") (PSU Statement No. 1). If I fail to address each and every issue in the testimonies of each of these witnesses, it does not imply agreement with those issues.

Q. What rate of return issues have been disputed in this case?

A. The Company's capital structure has been challenged by Mr. O'Donnell. Mr. Keller has accepted the Company's proposed capital structure and the Company's updated proposed cost of debt in this case. Mr. Crist does not comment on the capital structure ratios. The cost of equity has been disputed by each of the witnesses, although Mr. Crist has not offered a specific alternative cost of equity recommendation. The equity returns proposed by the OCA and I&E witnesses are entirely too low to reflect the risks of CPA and the prospective cost of equity.

There are two key factors that bear on the rate of return issue in this case. Aside from technical issues that I will discuss later in my rebuttal testimony, the Commission should take into consideration the following:

- A rate of return that will be reflective of the prospective capital cost rates.
- A rate of return that will reflect and be supportive of the Company's financial and business risk profile.

As I explain below, the recommendations of OCA and I&E fail to adequately consider these points and thereby understate the required cost of common equity in this proceeding.

Q. Please summarize the key points of your rebuttal testimony.

A. My key points are:

- Comparable Companies – Mr. Keller has made several deletions to the members of my Gas Group. Mr. O'Donnell has adopted my Gas Group along with the erroneous addition of UGI Corporation in his group. I disagree with the alterations to my Gas Group by Messrs. Keller and O'Donnell because my group fairly reflects the risks for the typical natural gas distribution utility and their alterations make their groups less reflective of the risks faced by a typical gas LDC. And, for Mr. O'Donnell, there is no need to analyze separately the cost of equity for NiSource.
- Discounted Cash Flow (DCF) – The DCF results proposed by the OCA and I&E witnesses are much too low to provide a reliable measure of the cost of equity. As such, alternative measures should be considered as has been Commission practice in other proceedings.
- DCF Growth Rate – Retention growth used by Mr. O'Donnell provides an inappropriate measure of investor expected returns. So too is Mr. O'Donnell's reliance on historic growth and his erroneous reliance on dividend and book value per share growth. Analysts' projections of future growth are the only reasonable evidence of the DCF growth rate in the context of setting prospective base rates.

- DCF Leverage Adjustment – The I&E and OCA witnesses have not refuted the accuracy of the Company's leverage adjustments to the DCF and beta component of the CAPM. Without such opposition, these should be accepted.
- Capital Asset Pricing Model – A reasonable application of the CAPM mandates using prospective yields on 30-year Treasury bonds, leverage adjusted betas, historical returns based on arithmetic means, and size adjustment.
- Risk Premium Analysis – The Risk Premium approach has previously been considered by the Commission and the results presented by the Company substantiate the Company's proposed return in this case.
- Comparable Earnings Approach – This approach substantiates the Company's proposed return in this case.

<u>Capital Structure</u>

Q. Are there differences in the proposed capital structures utilized by the rate of return witnesses in this case?

A. Yes. Mr. O'Donnell is alone in advocating an erroneous capital structure for CPA. Mr. Keller has accepted the Company's proposed capital structure, as it falls within the range of capital structures of the proxy group. Mr. O'Donnell's position is clearly contrary to long-standing Commission policy concerning capital structure ratios, most recently articulated in the Company's last rate case at Docket No. R-2020-3018835 and PECO Energy – Gas Division at Docket No. R-2020-3018929 (Order Entered June 22, 2021).

Q. Mr. O'Donnell has used historical data to support his position on capital structure. Does this position conform with Commission practice?

A. No. Mr. O'Donnell proposes to use a common equity ratio granted by other state regulators over the past 15-years (see OCA Statement No. 2 at page 44). This position does not conform with the Commission's use of the FPFTY and, hence, his proposal should be rejected. The Company has submitted a well-documented proposal with reasonable projections for the FPFTY.

Q. How does the Company's capital structure proposal differ from that advocated by Mr. O'Donnell?

A. Mr. O'Donnell's proposal is based on historical data that consists of the average common equity ratio established in rate case decisions by other state regulators. In essence, Mr. O'Donnell has proposed a generic and hypothetical capital structure for CPA without ever demonstrating that the Company's proposed capital structure is unreasonable. Rather, he merely proposes a capital structure that lowers the Company's revenue requirements. In reaching his conclusion on capital structure ratios, Mr. O'Donnell viewed four variables. They are: (i) the actual common equity ratio of CPA, (ii) the proxy group average common equity ratios, (iii) the consolidated common equity ratio of NiSource, and (iv) the average common equity ratio taken from rate case decisions in other states. He chose option (iv) as his proposal in this case. This approach essentially involves the use of a hypothetical capital structure that violates Commission precedent on the use of the actual capital structure. If other rate cases were to guide his selection of capital structure ratios, then he should have relied upon the UGI Utilities, Inc.-Electric Division (Docket No. R-2017-2640058 Order Entered October 25, 2018), Columbia, and PECO Energy decisions by the Commissions.

Q. Is there any basis to deviate from the Company's actual capital structure to set the rate of return in this case?

A. No. As I explained in CPA Statement No. 8 (see page 17), the Company's actual capital structure ratios (including the 54.34% common equity ratio) are fairly comparable to the companies in the comparison group and are therefore entirely reasonable and acceptable. Indeed, the range of common equity ratios for my Gas Group are represented by ratios that extend up to 56.0% for the year 2022, as shown below:

Atmos	55.0%
Chesapeake	56.0%
New Jersey Resources	45.5%
NiSource, Inc.	40.0%
Northwest	53.5%
OneGas	38.0%
South Jersey Industries	37.0%
Southwest	50.0%
Spire	51.0%

Hence, the common equity ratio for CPA is clearly within the range of reasonableness. That alone is sufficient to support the use of the Company's actual capital structure in this case. Mr. O'Donnell might have been led to a different conclusion if he had considered the common equity ratio utilized by this Commission rather than relying on the actions of other commissions. Indeed, in its Order Entered on October 25, 2018 in Docket No. R-2017-2640058, the Commission adopted a 54.02% common equity ratio for the Electric Division of UGI Utilities and in its Order entered on December 28, 2012 in Docket No. R-2012-2290597, the Commission accepted a 50.78% common equity ratio for PPL Electric Utilities, Inc. Furthermore, the Commission accepted a 54.19% common equity ratio in the Company's last rate case at Docket No. R-2020-3018835 (Order Entered February 19, 2021) and 53.38% common equity ratio for PECO Energy Company – Gas Division at Docket No. R-2020-3018929 (Order Entered June 22, 2021). Indeed, the Company's proposed common equity ratio of 54.34% is entirely reasonable based on prior Commission action. There is just no reason that the Commission should defer its decision-making authority on capital structure to actions by other state commissions. Moreover, the reasonableness of the Company's actual capital structure containing a common equity ratio of 54.34% is revealed by the data provided by both Messrs. O'Donnell and Keller. Their data shows that the Company's actual common equity ratio is well within the range employed by their barometer groups and, therefore, supports the level of common equity proposed by the Company. Those comparisons show that Mr.

O'Donnell's Comparison Group has common equity ratios within a range from 36.0% to 62.3% according to his Table 4 (see OCA Statement No. 2 at page 37). Mr. Keller found that the range of common equity ratios for his Barometer Group support the Company's proposed common equity ratio of 54.34%. Here, the Company's actual 54.34% common equity ratio falls clearly within those ranges. Hence, the Company's actual common equity ratio conforms with Commission policy that the actual, not hypothetical, common equity ratio should be employed.

Q. Mr. O'Donnell also claims that other "State regulators have been quite consistent with their rulings in natural gas cases for allowed common equity ratios based on investor sources of capital over the past 15 years." (See page 39 of OCA Statement No. 2). Is this correct?

A. No. The data shown by Mr. O'Donnell's Chart 4 provides a clear demarcation between cases decided after 2010 and those decided prior to 2011. According to Mr. O'Donnell's data, the average common equity ratio for cases decided prior to 2011 was 49.33%, while the average common equity ratio for cases decided more recently, after 2010, was 51.61%. Indeed, for the most recent two years, the common equity ratios have been above 52%. Hence, regulators have recognized the need for more common equity in the capital structures for natural gas utilities in more recent periods.

Q. Does Mr. O'Donnell provide clear justification for rejecting the Company's actual capital structure and substituting a different capital structure?

A. No. Mr. O'Donnell has not substantiated his position regarding the selection of hypothetical capital structure ratios, other than it achieves a lower revenue requirement. Aside from the hypothetical nature of his capital structure ratios, Mr. O'Donnell's approach represents a generic capital structure that would apply to any and all gas utilities. Furthermore, Mr. O'Donnell advocates a hypothetical debt ratio without using a hypothetical cost of debt related to the rate case decisions he relied upon. This results in a serious mismatch of debt ratio and debt cost. We know that there is a direct relationship between the cost of debt and the amount of financial risk shown by the debt ratio. That is to say, as the debt ratio increases, the cost of debt also increases. Mr. O'Donnell's proposal in this regard ignores this basic financial principle. Consequently, his proposal to use hypothetical capital structure ratios, if accepted, would result in providing CPA with a return on equity (i.e., one that would be lower) that is not commensurate with the actual financial risk of the Company.

Q. Do you have other concerns regarding Mr. O'Donnell's proposed hypothetical capital structure ratios?

A. Yes. Mr. O'Donnell has erroneously tilted his hypothetical capital structure ratios toward short-term debt. In its filing the Company has used a thirteen-month average balance of short-term debt to reflect the seasonal nature of these borrowings. This produced a short-term debt ratio of 3.89%. Gas utilities short term debt balances tend to vary on a seasonal basis to support the purchase of gas for storage injection in the summer and fall. In contrast, Mr. O'Donnell has imposed a 7.88% short-term debt ratio in his hypothetical capital structure, a 100% increase in the proportion of short-term debt in his structure. There is no basis for making this proposal. Short-term debt as a percentage of total debt is 8.51% ($103.3 million ÷ $1,213.8 million). Mr. O'Donnell has boosted that percentage to 15.76% (7.88% ÷ 50.00%). There is no basis for this proposal.

Q. Mr. O'Donnell also references the capital structure of NiSource. Is this appropriate?

A. No. Just as with his proposal to use a hypothetical capital structure that does not reflect CPA's actual capital structure, use of NiSource's capital structure would result in a mismatch between the applied capital structure and CPA's actual financial risk. Moreover, NiSource is a holding company, and its capital structure thus reflects the financial risk associated with ownership of multiple utilities, a large generation company, and unregulated competitive businesses. It is not appropriate to compare an operating utility capital structure to the capital structure of a parent holding company that holds these diverse utility and non-utility operations.

Q. Mr. O'Donnell brings up the issue of double leverage in his discussion of capital structure (see pages 41-42 of OCA Statement No., 2). Does this concept have any bearing on the capital structure ratios used for ratesetting purposes for CPA?

A. No. The Commission has never employed the double leverage concept in establishing the weighted average cost of capital in a rate case decision. This is in spite of the fact that all of the major utilities in the state are affiliated with holding companies that have the potential for different common equity ratios for the parent holding company and the subsidiary utility company.

Q. Should the Commission ignore the fact that the NiSource's common equity ratio has a 40% common equity ratio and CPA has a 54.34% common equity ratio?

A. There is nothing associated with the common equity ratios of the parent company and the utility subsidiary that warrants any departure from the Commission's past practice of using the utility's actual capital structure. It is noteworthy that there are several significant issues that impact the capital structure of NiSource that have no bearing on the capital structure of CPA. For NiSource, these items include:

i. A very large retained earnings deficit (i.e., negative retained earnings) that is related to the 2015 divestiture of Columbia Pipeline Group

ii. The parent consolidated capital structure contains debt obligations issued directly by other subsidiaries that are not relevant to the rate base or operations of CPA.

iii. The parent consolidated capital structure contains capitalized leases that for ratesetting purposes in Pennsylvania are considered operating leases

iv. The parent capital structure contains accumulated Other Comprehensive Income ("OCI") that relates to pension and OPEB benefits, cash flow hedges, and securities available for sale, which are not related to the manner that the CPA rate base is financed.

v. Large amounts of parent company debt that was used to finance goodwill, which is not part of the ratesetting process

It is apparent that none of the issues listed above have anything to do with the traditional concept of double leverage, i.e., using parent company borrowings to finance the equity of a subsidiary. Hence, Mr., O'Donnell's references to this concept are not relevant to the CPA/NiSource relationship in this case.

<u>Cost of Long-Term Debt Update</u>

Q. Have the opposing parties adopted the Company's proposed cost of debt?

A. Mr. Keller has adopted the Company's proposed updated cost of debt. Mr. O'Donnell is silent on the update.

Q. Have you updated the Company's cost of debt?

A. Schedule 1 of Exhibit No. 400R, provides the Company's cost of debt for the FPFTY. This schedule was an attachment to the response to interrogatory OCA-III-003. It reflects the actual cost of the new issue of promissory notes that were issued in March 2021. As shown on of Schedule 1 of Exhibit No. 400R the embedded cost of long-term debt is 4.58% for the FPFTY. This change increased the overall cost of debt by 0.04% (4.58% - 4.54%), from my original proposal. As shown on Schedule 2 of Exhibit 400R, the overall rate of return is now 7.89% vs 7.88% that was contained in the Company's original filing. Company witness Miller has adjusted the revenue requirements for this change.

<u>Opposing Parties Equity Proposals and Relevant Market Fundamentals</u>

Q. Is it necessary that the cost of equity set by the Commission support the Company's financial profile?

A. Yes, the cost of equity set by the Commission should allow the Company to maintain its financial integrity and credit quality. It is important to remember that utilities, including CPA, must be in a capital attraction position in all circumstances. A rate of return below the cost of capital provides a disincentive to investing capital in the Company's business. Consequently, the Commission should reject the proposal by Mr. O'Donnell to set the Company's return at 9.00% and Mr. Keller's proposal of 9.19%. Rather, based on the factors listed below, and for technical reasons set forth later in this rebuttal testimony, I have shown that the proposed returns by Mr. O'Donnell and Mr. Keller are much too low to reflect the risk and return for CPA.

Q. How do the cost of equity proposals by Mr. O'Donnell and Mr. Keller compare to the utility returns recently authorized by the Commission?

A. Technical disputes about methodology and data aside, the proposed costs of equity proposed by Mr. O'Donnell and Mr. Keller are simply not representative of the return investors can earn on other investments of comparable risk, including investments in other gas utilities like CPA. Indeed, the Commission established a 9.86% equity return for the Company in its last rate case at Docket No. R-2020-3018835. With rising capital cost rates, a higher, not lower, equity return is required in this case. The Commission has also granted equity returns of 9.54% for Citizens' Electric Company at Docket No. R-2019-3008212, 9.31% for Wellsboro Electric Company at Docket No. R-2019-3008208, 9.73% for Valley Energy at Docket No. R-2019-3008209, 10.8% for Pennsylvania-American Water Company ("PAWC") at Docket Nos. R-2020-3019369, R-2020-

3019371[1], and 10.24% for PECO Energy Company – Gas Division, Docket No. R-2020-3018929. With respect to the Columbia, PAWC and PECO Energy cases, these equity returns were established when the conditions of the COVID-19 pandemic were heightened in comparison to where the CPA case stands now. Moreover, for purposes of setting the Distribution System Improvement Charge ("DSIC"), the Commission has set a 10.20% equity return for gas distribution utilities see Docket No. M-2021-3025288 dated May 6, 2021. In the DSIC proceedings, DSIC recoveries are reconciled and therefore the 10.20% is guaranteed. In addition, the expected return on equity for Mr. O'Donnell's Gas Proxy Group is 9.8% according to Value Line, for year 2021 and 9.4% for the years 2024 – 2026 (See OCA Exhibit KWO-4), which represents a benchmark for the types of returns that investors expect for gas distribution utilities.

The rates of return on common equity of 9.00% proposed by Mr. O'Donnell and 9.19% proposed by Mr. Keller are seriously deficient and will not provide CPA with the opportunity to earn its investor required cost of capital for the fully projected future test year ending December 31, 2022 ("FPFTY"). As explained below, this is not the time for the Commission to be reducing the Company's authorized return when there is a compelling need for capital investment to rehabilitate aging infrastructures.

Q. Why would the 10.20% rate of return on common equity for DSIC purposes serve as a floor to the cost of equity in this case?

A. It just makes no sense that the cost of equity in a rate case could be any lower than the DSIC return. First, investments that carry the DSIC return should not be penalized with a lower return when they are included in the rate base when setting base rates. Second,

[1] The Commission's Opinion and Order in this case held that "We agree with the ALJ's rationale and recommendation on this issue, approving, as contained within the Joint Settlement, the Company's application of traditional ROE models and its analysis of current market conditions." *Pa. PUC, et al. v. Pennsylvania-American Water Company*, Docket Nos. R-2020-3019369 (Water), R-2020-3019371 (Wastewater), at p. 62 (Opinion and Order entered Feb. 25, 2021).

the DSIC return receives a true-up such that the achieved returns on DSIC investments equal the intended return in those proceedings. Rather than that situation, rates established in a base rate case merely provide an opportunity to achieve a particular return. That is to say, there is no true-up of the achieved return with the opportunity provided in a rate case decision. As such, the cost of equity established in a base rate case must be no lower than the rate of return on common equity used in the DSIC because there is additional risk associated when achieving a particular return in base rates thus requiring a higher return.

Q. Are there additional issues that the Commission should consider when setting the Company's return?

A. Yes. The investment community would be very concerned if the Commission were to adopt either of the positions of the OCA or I&E. If it were to do so, investors would see Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment. At present, Pennsylvania regulation is currently ranked Above Average/3 by Regulatory Research Associates ("RRA"), which reflects an upgrade that occurred on May 10, 2017. The rating system used by RRA includes three principal categories (i.e., Above Average, Average and Below Average with more refined positions within the categories designated by the numbers 1, 2 and 3).

Q. How would markets react if the Commission were to follow the proposals of OCA or I&E?

A. If the Commission were to follow the proposals of OCA or I&E, the regulatory ranking of Pennsylvania would certainly be jeopardized. The return on equity used by the Commission to set rates should embody in a single numerical value a clear signal of regulatory support for the financial strength of the utilities that it regulates. Although cost allocations, rate design issues, and regulatory policies relative to the cost of service are important considerations, the opportunity to achieve a reasonable return on equity represents a direct signal to the investment community of regulatory support (or lack thereof) for the utility's financial strength. In a single figure, the return on equity utilized to set rates provides a common and widely understood benchmark that can be compared from one company to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, and so forth) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Commission policies on technical matters, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Pennsylvania.

Q. Is there other evidence that shows the return on equity recommendations of the opposing parties are deficient?

A. Yes. One measure of market risk is provided by the OBOE Global Markets (formerly Chicago Board Options Exchange) Volatility Index ("VIX"). This index is a gauge of volatility in the equity market and, hence, provides a measure of risk. In 2020, the VIX averaged 32.21 as compared to 16.33 in 2019, which points to high risk in the equity market. It is well-established that greater volatility indicates higher risk, which, all else equal, translates into a higher cost of equity. It is widely accepted that high readings for the VIX are often accompanied by bearish sentiment and a low VIX is associated with bullish sentiment. The trading pattern of the VIX is typically inverse to the level of stock prices. That is to say, the VIX increases when stock prices are falling and the VIX declines when stock prices rise. This situation is sometimes associated with increases in the cost of equity when the VIX increases and vis-a-versa. The overall range of the index since 1990 has been 8.56 to 89.53. The peak in the index occurred on October 1, 2008 during the Financial Crisis. The lowest VIX occurred on November 1, 2017 during the previous bull market. For 2021 to date, the VIX was 24.37. This compares with the VIX in prior years of 12.12 in 2017, 18.46 in 2018, and 16.33 in 2019. We can see that the VIX has spiked upward with the COVID-19 pandemic and the onset of the recession. The recent VIX history has been:

Year	Average VIX
2017	12.12
2018	18.46
2019	16.33
2020	32.21
2021 YTD	24.37

While volatility in the stock market has subsided since the very beginning of the pandemic and recession, it continues to significantly exceed levels prior thereto as measured by the VIX. The current level of risk associated with common stocks, as revealed by the higher VIX in 2021, warrants a higher equity return at this time because the higher stock market volatility signifies higher risk that requires higher returns in compensation for the higher risk. Hence, the risk for common equity, which translates into the cost of equity, does not support a low equity return suggested by Messrs. Keller and O'Donnell.

Q. At page 70 of OCA Statement No. 2, Mr. O'Donnell observes that regulated ROEs have trended downward over the past 15 years. Please respond.

A. They have. But equity return trends should not be analyzed in isolation; instead, they should be analyzed in comparison to the corresponding public utility bond yields, which is known as the "regulatory premium." Most simply, the factor that has the most importance in this analysis is not the equity returns viewed in isolation. Instead, what is important is how much difference there is between utility bond yields (which are the yield provided to lower-risk bond investors) and the return provided to equity investors, who absorb additional financial risk in their investments. Over the 15-year period addressed by Mr. O'Donnell, the regulatory premiums have increased. This is shown by the data provided below.

Years	Number of Years	Average Regulatory Risk Premium
2001-2020	20	4.89%
2011-2020	10	5.59%
2016-2020	5	5.81%

What this shows is that the risk premiums implicit in rate case decisions during more recent periods of declining interest rates have increased. This is entirely consistent with the relationship of risk premiums and interest rates that I describe in my direct testimony (see CPA Statement No. 8 pages 33-34).

Q. Is there additional evidence that suggests that the cost of capital has been increasing?

A. Yes. The yield on 30-year Treasury bonds moved above the 2% level beginning in February 2021. In comparison, those yields closed out 2020 at 1.67% for December. By June 2021, the yield on 30-year Treasury bonds had moved to 2.16%, or an increase of 49 basis points (or 29%). Likewise, the yield on A-rated public utility bonds has increased to 3.16% in June 2021 from 2.77% in December 2020 -- a 39 basis point (or 14%) increase. One reason that explains the higher long-term interest rates can be traced to investor expectations of higher inflation. Indeed, there has been an upward burst in inflation recently following very low inflation that existed during the pandemic. Higher interest rates clearly point to higher capital costs prospectively. I will describe the Blue Chip forecast of interest rates and the continuation of this trend later in my rebuttal.

Q. How should the Commission view the return that it sets for the Company in order to continue to promote and encourage further accelerated replacement of aging infrastructure?

A. Supportive rate regulation encourages public utilities such as CPA to accelerate replacement of aging infrastructure. The markets look to supportive rate regulation in assessing investment decisions. Lowering the authorized rate of return on equity to the levels proposed by Mr. Keller and Mr. O'Donnell will signal to investors that Pennsylvania is pulling away from its prior support for accelerated infrastructure replacement.

Q. How is the remainder of your testimony organized?

A. I will cover the issues of (i) the composition of the proxy (i.e., barometer) group, (ii) the weight to be given to the DCF method, (iii) the DCF growth rate, (iv) the leverage adjustment to the DCF and CAPM methods, (v) the CAPM method, (vi) the Risk Premium analysis, (vii) Comparable Earnings, and (viii) the PSU proposal.

<u>Proxy Group</u>

Q. Are there differences in the proxy groups utilized by the rate of return witnesses in this case?

A. Yes. Mr. Keller includes only seven companies from my Gas Group in his Barometer Group. He drops New Jersey Resources and Southwest Gas Holdings. Mr. O'Donnell accepts all of the companies in my Gas Group and then inserts UGI Corporation in the Comparison Group, and separately analyzes the cost of equity for NiSource.

Q. Mr. O'Donnell makes a separate calculation of the cost of equity for NiSource. Is this analysis helpful in setting the equity return in this case?

A. No. The Commission's policy has been to use a proxy (i.e., barometer) group analysis to set the return on equity when the utility's own stock is not traded. The Commission's approach in this regard makes perfect sense because it produces a return that is available on other enterprises of comparable risk. The Commission's practice has focused primarily on a proxy group analysis for setting the return on equity. Mr. O'Donnell has provided no sound basis to deviate from this approach and look at NiSource separately in this case.

Q. Should UGI Corporation be included in the Comparison Group?

A. No. Non-utility operations comprise 85% of revenues, 74% of net income, and 73% of assets for UGI Corporation. This makes UGI Corporation a non-comparable company and should not be included in a Comparison Group for this case. Indeed, the Commission specifically excludes UGI Corporation from the Gas Distribution Company Barometer Group in its Quarterly Earnings Report (Docket No. M-2021-3025288, adopted at Public Meeting held May 6, 2021).

Q. Mr. Keller used the percentage of revenues devoted to utility operations as a criterion for screening companies to assemble his Barometer Group. Is this a correct criterion?

A. No. For utilities, the percentage of regulated revenues cannot be used as the criteria to select members of the Barometer Group. This is because the margins on other business segments within Barometer Group companies are generally dissimilar to the utility business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the large revenues and small margins associated with that business, when contained in potential Barometer Group companies. That is to say, energy trading generates large amount of revenues, but little profits because the margins on such trades are very small.

Q. How do the percentages of utility income and assets compare to the companies contained in your Gas Group?

A. Those results are shown below as taken from my response to interrogatory I&E-RR-5-D:

		Percent Utility Operations		
		Revenues	Income	Assets
ATO	Atmos Energy Corp.	96%	73%	93%
CPK	Chesapeake Utilities Corp.	46%	84%	79%
NJR	New Jersey Resources Corp.	55%	35%	64%
NI	NiSource, Inc.	100%	106%	88%
NWN	Northwest Natural Gas	96%	85%	97%
OGS	One Gas, Inc.	98%	100%	100%
SJI	South Jersey Industries, Inc.	41%	134%	89%
SWX	Southwest Gas Corp.	47%	76%	83%
SR	Spire, Inc.	96%	94%	82%
	Average	75%	87%	86%

As shown above, the percentage of utility assets is above 63% for all members of my Gas Group. As such, these data show that no elimination to my Gas Group is appropriate in this case. Moreover, the Commission uses my Gas Group when applying the cost of equity models in its Quarterly Earnings Report (Docket No. M-2021-3025288 adopted at Public Meeting held May 6, 2021).

Cost Of Common Equity - Discounted Cash Flow

Q. The DCF model has been used by Messrs. Keller, O'Donnell and you as one method to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). The simplified DCF model makes the assumption that there is a single constant growth rate, there is a constant dividend payout ratio, that price – earnings multiples do not change, and that the price of stock, earnings per share, dividends per share and book value per share all have the same growth rate. We know from experience that those assumptions are not realistic, because the stock market reveals performance that is very different from the assumptions of the DCF.[2] The use of the DCF alone thus does not provide a fully realistic analysis. Instead, multiple methods provide a more comprehensive and reliable basis to establish a reasonable equity return for CPA. The Commission has acknowledged the usefulness of other methods, such as CAPM and Risk Premium, as a check on the reasonableness of the DCF return.

I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[3]

Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Mr. Keller, Mr. O'Donnell, and me.

Q. How do the growth rates compare for your Gas Group, Mr. Keller's barometer group, and Mr. O'Donnell's Comparison Group.

A. I used a 7.50% growth rate for my Gas Group. Mr. Keller used 5.70% for his Barometer Group (see I&E Ex. 2 – Schedule 9) and Mr. O'Donnell used a 4.3% to 7.8% growth rate using forecasts and 4.8% to 6.9% using history for his Comparison Group (see OCA

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[2] The growth rate variables shown on Schedules 8 and 9 of CPA Exhibit 400 shows that the assumption associated with the simplified DCF model are not reasonable.

[3] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

Statement No. 2 at page 66-67).

Q. Do the DCF results utilized by Mr. Keller provide a reasonable representation of the cost of equity?

A. No. The principal purpose of assembling a Barometer Group is to avoid relying on data for a single company or companies that may not be representative and to thereby smooth out abnormalities. That said, when the results of individual members of the Barometer Group are unreasonable on their face, the reliability of the method being used, or the witness' application of that method, must be questioned. As indicated below, the following DCF results presented by Mr. Keller falls into that category:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Chesapeake Utilities	1.85%	+	4.41%	=	6.26%
Northwest Natural Gas	3.56%	+	3.90%	=	7.46%
OneGas, Inc.	3.19%	+	5.50%		8.69%

These returns are unreasonable because they produce DCF returns below 9.0%.

Q. What are the DCF results for the remaining members of Mr. Keller's Barometer Group?

A. Those results are:

Ticker	Company	D_1/P_0	+	g	=	k
ATO	Atmos Energy Corp.	2.74%	+	7.14%	=	9.88%
NI	NiSource, Inc.	3.78%	+	6.29%	=	10.07%
SJI	South Jersey Industries	5.44%	+	6.43%	=	11.87%
SR	Spire, Inc.	3.90%	+	6.20%	=	10.10%
	Average	3.97%	+	6.52%	=	10.48%

Q. Please summarize Mr. O'Donnell's DCF methodology.

A. In his DCF analyses, Mr. O'Donnell computes the dividend yields by dividing the annualized dividend for each proxy group company by the average stock price for March

26, 2021 through June 18, 2021 (see page 56 of OCA Statement No. 2). He arrives at a range of dividend yields of 3.2% to 3.3% using 1, 4, and 13-week periods. He then adds a growth rate taken from five sources. He employs the "plowback" method, and Value Line historical growth rates of earnings, dividend and book value, as well as the Value Line forecasts of earnings, dividends and book value growth, and earnings forecast by CFRA and Schwab (see OCA Statement No. 2 at pages 57-62).

Q. At pages 60-61 of OCA Statement No. 2, Mr. O'Donnell claims "that it would be inaccurate to use only earnings growth rates in the DCF." Do you agree?

A. No. Mr. O'Donnell presents DPS (dividends per share) and BPS (book value per share) growth rates in addition to EPS (earnings per share) growth. Mr. O'Donnell is incorrect to believe that DPS and BPS have any role in the DCF model. The theory of the model rests on the assumption that there will be a constant price-earnings multiple, and therefore the price of stock will increase at the same rate as earnings growth – that is, EPS growth is the metric that drives the DCF analysis. Moreover, with the constant payout ratio assumption of the DCF, dividend growth will equal earnings growth in the long-term. Finally, with a consistent market-to-book ratio assumption of the DCF, book value per share will equal the other variables of growth, i.e., earnings per share and dividends per share.

Q. As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?

A. As noted above, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is also important to recognize that analysts' forecasts significantly influence investor growth expectations. Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model are forecasts of earnings per share growth.[4] Therefore, Mr. O'Donnell's reliance on historic rates of growth in earnings, dividends and book value should be rejected.

Q. Please discuss the limitations of Mr. O'Donnell's plowback growth analysis.

A. Plowback, otherwise known as retention growth, along with external financing growth, is another means of describing book value per share growth. Other factors also contribute to earnings growth that are not accounted for by the retention growth formula, such as sales of new common stock that Mr. O'Donnell has excluded in his DCF growth rate analysis, reacquisition of common stock previously issued, changes in financial leverage, acquisition of new business opportunities, profitable liquidation of assets, and repositioning of existing assets. In my view, book value per share growth, or its surrogate retention (plowback) growth, does not represent the proper financial variable to be considered when selecting the DCF growth component. The plowback approach to the DCF merely adjusts an assumed return on book common equity by the difference between the dividend yield on book value and the dividend yield on market value. The table provided below shows how his DCF result can be expressed from these values. This shows how the return expected by investors for the Comparison Group of 9.8% for 2021 and 9.4% for 2024-2026 (see Exhibit KWO-4), or an average of 9.6% (9.8% + 9.4% = 19.2% ÷ 2) is adjusted to a much lower DCF return. I have demonstrated this using the average of Mr. O'Donnell's three dividend yields (i.e., 3.2% + 3.3% + 3.2% = 9.7% ÷ 3 = 3.2%).

[4] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

Return on Equity	9.6%
Dividend Yield on Book Value	-5.3%
Dividend Yield on Market Value	3.2%
Result	7.5%

It should be noted that the Commission has not previously adopted a retention growth (i.e., plowback) approach in the DCF analysis. A key component of retention growth is the analyst's assumed return on book common equity. Mr. O'Donnell does not and cannot explain why an investor expected return of 9.6% should be reduced to 7.5%. As shown above, the plowback approach advocated by Mr. O'Donnell is clearly inconsistent with the traditional form of the DCF model used by the Commission.

Q. What DCF results would be obtained by relying on forecasts of earnings per share growth that is typically considered by the Commission?

A. Mr. O'Donnell submits earnings per share forecast growth rates of 7.3% by Value Line, 5.8% by CFRA, and 5.7% by Schwab (see Exhibit KWO-2). The average earnings per share growth rate is 6.3% (7.3% + 5.8% + 5.7% = 18.8% ÷ 3). The resulting DCF return is 9.5% (3.2% + 6.3%). This provides a far more reasonable DCF result than the 8.84% average DCF return advocated by Mr. O'Donnell (see OCA Statement No. 2 at page 68). As I describe in my pre-filed direct testimony, forecast earnings growth is the only valid measure of growth for DCF purposes.

Cost of Common Equity - Leverage Adjustment

Q. At pages 35-41 of I&E Statement No. 2, Mr. Keller responds to your leverage adjustment and argues that it should be rejected. Do you agree?

A. No. Mr. Keller states that he opposes the leverage adjustment. In his discussion of my leverage adjustment, Mr. Keller mentions market-to-book ratios ("M/B") (see page 36 of I&E Statement No. 2). I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio. Mr. Keller offers three reasons for not making a leverage adjustment. First, Mr. Keller notes that the credit rating agencies assess financial risk in terms of a company's income statement in their analysis of the creditworthiness of a company (see page 39 of I&E Statement No. 2). I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market-required cost of equity for a company. The credit rating agencies are only concerned with the interests of lenders. They are judging risk associated with a company's ability to make timely payments of principal and interest. Hence, they are not concerned with the cost of equity or how it is applied in the rate-setting context. While Mr. Keller's observation is correct, it has no relevance to my leverage adjustment.

Q. Second, Mr. Keller also questions your leverage adjustment by reference to prior Commission orders (see pages 39-40 of I&E Statement No. 2). Please comment.

A. Mr. Keller points to several decisions where the Commission declined to make a leverage adjustment, including rate cases for Aqua Pennsylvania, the City of Lancaster Water Department, UGI – Electric Division, and Columbia Gas of Pennsylvania, (see page 41 of I&E Statement No. 2). The fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Mr. Keller does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance. Columbia has not proposed a management performance adjustment in this case. Just as an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada[5] formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case. As to the UGI – Electric Division case, there the Commission granted a management performance increment rather than a leverage adjustment when arriving at a 9.85% equity return. Finally, in the last CPA rate case, the Company elected to accept the DCF return submitted by I&E without regard to the leverage adjustment or management performance.

Q. Third, Mr. Keller argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

A. Mr. Keller contends that information presented to investors, such as that included in the Value Line reports, argues against my leverage adjustment because investors base their investment decisions on book value (see pages 40-41 of I&E Statement No. 2). However, the Value Line reports clearly show the market capitalization of each company in his barometer group. This means that investors are well aware of the market capitalization of the gas utility stocks that Mr. Keller relies upon for his analysis of the cost of equity. More importantly, I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that

[5] 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.

determines the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. The financial risk associated with the book value capital structure is different from the market value of the capitalization, which I clearly demonstrate on Schedule 10 of CPA Exhibit No. 400. Hence, the observation of Mr. Keller is misplaced because I have clearly shown the difference in financial risk and that risk difference must be taken into account when arriving at an equity return that is applicable to the weighted average cost of capital using book value weights.

Q. At pages 39-40 of I&E Statement No. 2, Mr. Keller claims that "true financial risk is a function of the amount of interest expense…" Is he correct on this point?

A. No. Capital structure provides the correct measure of financial risk of a firm. As Morin explained, "Financial risk stems from the method used by the company to finance its investments and is reflected in its capital structure."[6] Hence, the method I used for the financial risk adjustment is entirely proper.

Q. At pages 97-100 of OCA Statement No. 2, Mr. O'Donnell disagrees with your leverage adjustment. Does he adequately support his opposition?

A. No. Mr. O'Donnell states that my adjustment "is, without a doubt, a market-to-book adjustment" (see page 99 of OCA Statement No. 2). He has not shown, nor could he, that my leverage adjustment is the same as a "market-to-book" adjustment. There is no factor in my adjustment that provides a conversion of a DCF return based upon any particular market-to-book ratio. Likewise, for the CAPM. Moreover, Mr. O'Donnell cannot show how my application of the Hamada formula to the Value Line beta changes by a market-to-book factor.

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[6] Morin, Roger A., New Regulatory Finance, Public Utilities Reports, Inc., 2006, p. 45.

Cost of Common Equity - Capital Asset Pricing Model

Q. Do you have concerns regarding Mr. Keller's and Mr. O'Donnell's applications of the CAPM?

A. Yes. The CAPM results proposed by these witnesses understate the cost of equity for a number of reasons: (i) Mr. Keller's use of the yield on 10-year Treasury notes rather than longer-duration Treasury offerings, (ii) Mr. O'Donnell's consideration of historical geometric means to calculate total market return, (iii) their failure to use leveraged adjusted betas, and (iv) their failure to make a size adjustment. Moreover, I disagree with Mr. O'Donnell's CAPM as it relates to the lack of a prospective yield on Treasury bonds and a market risk premium that is unreflective of the forward-looking prescription of the CAPM that requires use of investor-expected returns.

Q. How does the yield on 10-year Treasury notes used by Mr. Keller compare with yields on longer-term Treasury bonds?

A. The Blue Chip report dated June 1, 2021 shows this comparison. For the first quarter of 2021, the gap was 0.75% (2.07% - 1.32%) between the yields on 30-year and 10-year Treasury obligations. For the period 2023-2027, that gap is projected at 0.6% (3.5% - 2.9%) according to that same source. This shows a systematic understatement of CAPM returns by Mr. Keller. Short-term rates respond more to the monetary policy actions taken by the Federal Open Market Committee ("FOMC"), while long-term rates are more a reflection of investor sentiment of their required returns. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return. Use of shorter term rates, such as Mr. Keller's 10-year Treasury Notes yields, are more susceptible to Fed policy actions.

Q. How has Mr. Keller understated the risk-free rate of return?

A. The support for his risk-free rate of return is shown on his Schedule 11 of I&E Exhibit No. 2. There, he incorrectly gives the same weight to the yield on 10-year Treasury notes for the third and fourth quarters of 2021 and first, second and third quarters of 2022 as he does for the entire five-year period 2022 through 2026. This approach leads to a seriously understated risk-free rate of return. There are several problems with his approach. First, even if 10-year rates are used, it is necessary to correct the weights assigned to the forecast data presented by Mr. Keller. I have revised his forecast below, based upon the latest Blue Chip report dated June 1, 2021. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future. This is consistent with expectations of higher inflation in the future. And, the Commission should be responsive to higher equity returns in this situation.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2021	1.7%	2.4%
2022	2.0%	2.6%
2023	2.4%	2.9%
2024	2.7%	3.3%
2025	3.0%	3.6%
2026	3.2%	3.8%
Average	2.5%	3.1%

The resulting risk-free rate of return is 2.5% using the yield on 10-year Treasury Notes, as compared to Mr. Keller's 1.9%, and 3.1 using the yield on 30-year Treasury Bonds.

Q. How should these results be used in the CAPM?

A. The market premium ("Rm – Rf") should be revised to reflect the correct risk-free rate of return shown above. The size adjustment of 1.02% must also be incorporated into the CAPM (see page 38 of CPA Statement No. 8). Those results are:

	Rf	+	*β*	(	*Rm*	-	*Rf*	) +	*size*	=	*K*
Barometer Group	2.50%	+	0.85	(	10.82%	-	2.50%	) +	1.02%	=	10.59%

This CAPM result employs the betas (“β) and market return (“Rm”) proposed by Mr. Keller.

Q. At pages 42-43 of I&E Statement No. 2, Mr. Keller disagrees with your size adjustment applied to the CAPM analysis. Has he substantiated his argument?

A. No. As a preliminary matter, recent Federal Energy Regulatory Commission’s (“FERC”) orders specifically prescribe an adjustment to the CAPM due to the size of an enterprise. [171 FERC ¶61,154] It is noteworthy that CAPM provides compensation solely for systematic risk. In making his arguments, Mr. Keller claims, “the technical literature he cites supporting investment adjustments related to the size of a company is not specific to the utility industry; therefore, has no relevance in this proceeding.” This supposes that there is distinction between regulated utilities and unregulated industrial companies when related to the impact on the cost of equity related to size. But that is not enough to reject this adjustment. This is because the size adjustment that I use is derived from the Ibbotson study that included, among other industries, public utilities. So, I have considered the utility industry in my adjustment. The Wong article that Mr. Keller cites provides no support for rejecting the size adjustment. The Wong article that he relies upon was authored twenty (20) years ago, and employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because utilities continue to have lower betas than many other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see “The Cross-Section of Expected Stock Returns,” The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns.

Q. Does Mr. O’Donnell’s CAPM analysis produce reasonable results?

A. No, it does not. Mr. O’Donnell says that his CAPM results are between 6.0% and 8.0% (see at page 83 of OCA Statement No. 2). This clearly is totally inconsistent with the CAPM that I provided above using Mr. Keller’s data, the DCF, and Comparable Earnings (showing returns of 9.00% to 10.00%) as Mr. O’Donnell has applied it. Such low returns are simply not credible.

Q. Concerning Mr. O’Donnell’s CAPM, why is it appropriate to include forward-looking data in the CAPM results?

A. Just like all market models of the cost of equity, CAPM is an expectational model. Mr. O’Donnell’s CAPM approach suffers from the infirmity of not positioning the risk-free rate of return in a forward-looking manner – rather he used historical results obtained from the past year. To remedy this shortcoming, at least in part, current data should be supplemented with forward-looking data. After all, Mr. O’Donnell uses forecasted information extensively in his DCF analysis when considering the appropriate growth rate. To be consistent, forecasts of total market returns should likewise be considered.

Q. Mr. O’Donnell uses, among other inputs, historical data for his market return component of the CAPM. What are your observations regarding Mr. O’Donnell’s use of the geometric mean when he analyzed historical data?

A. Mr. O'Donnell has incorrectly used the geometric mean in his historic analysis of the total market returns (see at page 78 of OCA Statement No. 2). The theoretical foundation of the CAPM requires that the arithmetic mean be used because it conforms to the single period specification of the model and it provides a representation of all probable outcomes and has a measurable variance. It has been established that the arithmetic mean best describes expected future returns -- the objective of the CAPM. The arithmetic mean provides the correct representation of all probable outcomes and has a measurable variance. In contrast, use of the geometric mean, which Mr. O'Donnell advocates, consists merely of a rate of return taken from two data points which would have no measurable variance (i.e., the dispersion of the returns cannot be calculated with a geometric mean because the multitude of returns from the intervening years between the beginning and ending values is ignored in the geometric mean). So, while a geometric mean will capture the growth from an initial to a terminal value, it cannot provide a reasonable representation of the market premium in the context of the CAPM because the model requires a single period return expectation of investors. The arithmetic mean provides an unbiased estimate, provides the correct representation of all probable outcomes, and has a measurable variance.

As stated by Ibbotson:

> *Arithmetic Versus Geometric Differences*
>
> For use as the expected equity risk premium in the CAPM, the arithmetic or simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, not geometric, subtraction.
>
> *Arithmetic Versus Geometric Means*
>
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth

> values.…This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) in order to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154

As such, the geometric mean should not be used in the CAPM. With the arithmetic mean, the market risk premium is 6.1% (12.2% - 6.1%) as revealed in the 2021 SBBI Yearbook.[7]

Q. What problem have you detected in Mr. O'Donnell's development of the market risk premium component of the CAPM?

A. Mr. O'Donnell has used market risk premiums that range from 4.25% to 6.25% (see page 81 of OCA Statement No. 2). These market risk premiums are entirely too low. Part of the problem relates to his use of non-standard sources for the market risk premium consisting of Blackrock, Grantham Mayor Van Otterloo, JP Morgan, Morningstar (10-year returns), Research Affiliates, and Vanguard, and his consideration of geometric returns when using historical data.

Q. Mr. O'Donnell also challenges the adjustment that you made to the results of the CAPM for the size of the Gas Group. Please respond.

A. There is no merit to Mr. O'Donnell assertion that recognition of the size premium causes double-counting for this risk factor (see pages 119-121 of OCA Statement No. 3). As a preliminary matter, my size adjustment relates to my Gas Group and is not based on either CPA or NiSource. A size adjustment is necessary because the financial impact of

[7] Mr. O'Donnell has erroneously reported the Long-Term Govt. Bond return as 8.7%, when the correct return is 6.1%

changes in specific dollar amounts of revenues and costs have a magnified influence on a small company because there are fewer dollars over which those revenues or costs can be spread. The SBBI/Morningstar Yearbook clearly demonstrates that the simple CAPM does not reflect the return that is associated with small size. As Ibbotson has stated:

> The security market line is based on the pure CAPM without adjusting for the size premium. Based on the risk (or beta) of a security, the expected return should fluctuate along the security market line. However, the expected returns for the smaller deciles of the NYSE/AMEX/NASDAQ lie above the line, indicating that these deciles have had returns in excess of those appropriate for their systematic risk.[8]

Cost of Common Equity – Other Methods

Q. At page 19 of I&E Statement No, 2, Mr. Keller explains why he excluded the Risk Premium and Comparable Earnings methods. Do you agree?

A. No. Mr. Keller claims the Risk Premium method is a simplified version of the CAPM, is subject to the same faults as CAPM, and does not recognize company-specific risk through beta (see pages 17-18 of I&E Statement No. 2). And he further asserts that the Comparable Earnings method is too subjective, and it is debatable whether historic accounting values are representative of the future. The Risk Premium method provides a reasonable measure of the cost of equity because it is based upon the utility's own borrowing rate. Since the yield on public utility debt provides the foundation for the Risk Premium method, its result reflects the fact that common equity carries more risk than utility debt. Moreover, the Risk Premium method is a more comprehensive measure of the cost of equity because it measures more than just systematic risk as provided by the beta in the CAPM. As to the Comparable Earnings method, it complies with the comparable returns standard for a fair rate of return as prescribed by Bluefield.

Q. What does Mr. Keller say about your Risk Premium analysis?

[8] 2017 SBBI Yearbook, page 7-15.

A. Mr. Keller makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision making process to the utility ratesetting process (see pages 18-19 of I&E Statement No. 2). In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Mr. Keller's assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. I incorporated current interest rates when I developed my Risk Premium cost of equity of 10.00%. Hence, my Risk Premium cost rate is fully responsive to changing market fundamentals.

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity which must be higher than the cost of debt in recognition of the higher risk of equity (see CPA Statement No. 8 page 31). So, while Mr. Keller and Mr. O'Donnell decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. Indeed, the Risk Premium approach provides for direct reflection of prospective interest rates in the model and therefore should be given weight in determining the equity cost rate in this case.

Q. At page 123 of OCA Statement No. 2, Mr. O'Donnell disagrees with your Risk Premium results because he believes that the best predictor of future yields are the current yield curve. Is this correct?

A. No. There is no merit to Mr. O'Donnell's argument in this regard. For if his premise were true, then the best predictor of future earnings would be today's earnings. Since all rate of return witnesses rely upon earnings forecasts to some degree, then forecasts of interest rates would follow that logic. Use of forecasts accommodates the reality that the future will diverge from current circumstances to some degree. I am sure that everyone would agree that the coronavirus pandemic will eventually be resolved and the future will be quite different than today.

Q. Please respond to the criticism of the Comparable Earnings approach.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital.

The Comparable Earnings approach satisfies the comparability standard established in the *Hope* case that specifies that the return to the utility should provide it "with returns on investments in other enterprises having corresponding risks." In addition, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets. Moreover, in a 1994 study that addressed the ROE issue, John Olson (then with Merrill Lynch) established that ROEs from non-regulated companies provide better assessment of investor requirements than those available for regulated utilities.[9]

Q. At page 27 of I&E Statement No. 2, Mr. Keller believes that it was "arbitrary" and "unjustified" for you to use 20% as the point where returns would be viewed as highly profitable and excluded from the Comparable Earnings approach. Please respond.

A. There must be some point of demarcation to identify the high returns that Bluefield rejects. It is true that a lower value could also be selected, but because I have not set any lower bound as a cut-off, the 20% threshold is reasonable. If something lower were to be advocated, then a lower bound would need to be established to bring balance to the resulting returns.

PSU Proposal

Q. PSU witness Mr. Crist argues that the cost of capital for CPA is lower, which can be traced to the availability of the DSIC. Do you agree?

A. No. As I explained at page 7 of CPA Statement No. 8, all of my Gas Group companies already have a DSIC. So, whatever the benefit of the DSIC to CPA and the members of the Gas Group, it is already reflected in the results of the models that I use to measure the cost of equity. To consider it again, would result in double-counting the benefits of the DSIC.

Summary

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. O'Donnell, and Mr. Keller significantly understate the cost of common equity for CPA. Furthermore, Mr. O'Donnell's capital structure should be rejected for all the reasons previously stated. Indeed, the CPA's capital structure proposed by the Company is entirely reasonable for this case.

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[9] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

Given the company-specific risk factors, an opportunity to earn a cost of equity of 10.95%, is reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Estimated at December 30, 2022

Date of Issuance	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
November 28, 2005	5.920%	$ 54,515,000	$ 3,227,288	
December 14, 2007	6.865%	58,000,000	3,981,700	
December 16, 2010	6.020%	28,000,000	1,685,600	
March 28, 2012	5.355%	30,000,000	1,606,500	
March 28, 2012	5.890%	35,000,000	2,061,500	
November 28, 2012	5.260%	65,000,000	3,419,000	
June 9, 2013	5.530%	23,000,000	1,271,900	
December 18, 2013	6.290%	32,000,000	2,012,800	
December 18, 2014	4.430%	30,000,000	1,329,000	
March 1, 2015	4.150%	60,000,000	2,490,000	
September 1, 2015	4.505%	60,000,000	2,703,060	
March 1, 2016	4.186%	45,000,000	1,883,610	
January 31, 2017	4.439%	85,000,000	3,772,810	
June 30, 2018	4.528%	80,000,000	3,622,320	
November 30, 2019	3.687%	80,000,000	2,949,600	
March 31, 2020	3.8716%	110,000,000	4,258,760	
March 31, 2021	3.6521%	110,000,000	4,017,310	
June 30, 2022	3.6700%	125,000,000	4,587,500	
Total Long-Term Debt		1,110,515,000	50,880,258	4.58%
Short Term Debt (Twelve month average)	0.85%	103,335,410	878,351	
Total Debt		$ 1,213,850,410	$ 51,758,609	4.26%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.
Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	41.77%	4.58%	1.91%
Short Term Debt	3.89%	0.85%	0.03%
Total Debt	45.66%		1.94%
Common Equity	54.34%	10.95%	5.95%
Total	100.00%		7.89%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 28.8921% income tax rate (10.31% ÷ 1.94%)	5.31 x
Post-tax coverage of interest expense (7.89% ÷ 1.94%)	4.07 x

N. PALONEY

COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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 have testified before the Commission on behalf of Columbia in its 2015, 2016, and 2018 base rate cases at Docket Nos. R-2015- 2468056, R-2016-2529660, and R-2018-2647577. In addition to base rate proceedings in Pennsylvania, I also have submitted testimony in support of Columbia's request to increase the cap on its Distribution System Improvement Charge (Docket No. P-2015-2521993) and in an abandonment proceeding (Docket No. A-2015-2513395). I also have testified before the Public Service Commission of Maryland on behalf of Columbia Gas of Maryland as a cost of service witness in Case No. 9316 and as a policy witness in Case Nos. 9354 and 9480.

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 Projected Future Test Year ("FPFTY") (through December 31,2021), that have been incorporated in Columbia witness Miller's cost of service analysis (Columbia Statement No. 4).

II. FULLY PROJECTED FUTURE TEST YEAR – O&M EXPENSE

Q. What is the basis for the forecasted O&M expense included in the Fully Projected Future Test Year?

A. The forecasted O&M expense included in the Fully Projected Future Test Year test period is derived from the Company's most recent O&M budget.

Q. What is Columbia's O&M expense budget methodology?

The O&M expense budgeting methodology used by Columbia is a combination of a "top down" and "grass roots" approaches. The O&M expense budget serves as a key component of the overall Columbia budget and as a cost management tool for both 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'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 and regulatory commitments 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 then combined with a corporate-level budget to arrive at a total company budget. I will discuss the corporate-level budget later in my testimony.

The Company's O&M budget is developed by department and by cost element, with the assistance of the NCSC Financial Planning department. Each department's budget is reviewed with and approved by the Vice President of Financial Planning and Analysis, Chief Operating Officer and the Company President. 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 the Company and parent company 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 the first quarter.

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 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 certain cases, budget variances will occur to address or take advantage of unforeseen general or operational conditions. In cases where a variance is driven by unforeseen general or operational conditions, the variance may not be reduced or mitigated, but may result in a departmental overrun. In this case, documentation of the drivers of the variance is maintained and evaluated in future planning cycles to ensure proper consideration of new and developing forecast items.

Q. Does the O&M expense budgeting methodology and process described in your testimony result in an accurate estimate of expenses to be incurred during the Fully Projected Future Test Year?

A. Yes. Notwithstanding all of the challenges that resulted from COVID in 2020, Columbia underspent the original O&M budgets by a margin of one half of one percent. Please refer to Exhibit NP-1 accompanying this testimony for a comparison of actual results versus the annual original O&M budget for the years 2009 through 2020. Overall, Exhibit NP-1 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 Projected Future Test Year.

Notably, in eight of the last twelve 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 and 2016, Columbia underspent the original O&M budgets by margins of 0.63% and 0.91%, respectively.

Columbia has experienced a variance of less than 5% to the original O&M budget in eight of the last eleven years, with the only exceptions being 2011, 2017 and 2018, when the variances were approximately 6.44%, 8.17% and (8.36%), 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 2017, three factors drove the variance. The first was the O&M portion of a large one-time prepayment to the Pension Plan in the amount of $8.45 million. The second driver was a $1.8 million overspend in Gas Operations. The last driver was an incentive compensation payout greater than budgeted, due to positive business results. Adjusting for those three items, the total O&M variance in 2017 was 0.43%.

The budget variance in 2018 was driven by two factors. First, as a result of the Company's rate case settlement, the Commission allowed the Company to amortize the 2017 prepayment over a period of ten years. This resulted in an unbudgeted credit to pension expense in 2018. Secondly, the engagement of NCSC employees in the Merrimack Valley event's recovery efforts contributed to the variance. The Company estimates that the NCSC billings it received were reduced by approximately $2.7 - $3.1 million during the last four months of 2018. Adjusting for those two items, the total O&M variance in 2018 was approximately (1.0%).

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, financial planning and accounting, in-house legal, human resources, corporate insurance, and regulatory amortizations.

Forecasted Labor Expense

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 798 active full-time employees for 2021 and 2022, 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 reflects an increase above the ending Historic Test Year ("HTY") level of 767 active full-time employees.

Q. What is the primary drivers for the Company's increased headcount?

A. The primary driver for the Company's increase headcount is to provide support to the Company's ongoing operational activities to provide safe, reliable service to customers.

Positions supporting ongoing operations are most often filled from within the Company's existing employee ranks, and bargaining unit agreement provisions can affect the bidding and selection process so that vacancies are held open for certain periods while applicants temporarily occupy a position before making a final decision. Once the new positions are filled by existing employees, the employees' former positions are then filled by new hires.

Q. Please explain the Company's hiring process to fill field positions.

A. For hiring of field employees, the company utilizes a "wave hiring" process. Wave hiring is built upon creating "pools" of applicants, and then offering a job to an applicant in the "pool". Pools typically consist of 20 applicant**s.** The Company has plans for wave hiring in April, June and October of 2021. The Company will provide updates sharing the results of the wave hiring as requested.

Q. Please explain the increase in the budgeted labor from the HTY to the FTY.

A. See the Company's response to Standard Data Request GAS RR-26 for a summary of labor increases. The adjustments to get to the FTY budget include adjustments for filled vacancies, headcount reductions related to NiSource Next, wage increases and adjustments to the allocation of labor dollars to capital and expense. Please see

Company Witness Kempic's testimony at Columbia Statement No. 1 for further discussion on NiSource Next.

Q. Are filled vacancies included in the normalized labor expense for the FTY?

A. Yes, they are. Included in normalized test year costs are costs associated with 31 vacancies. Total vacancies were reduced to 31 as the Company has also included a headcount reduction of 16 resulting from NiSource Next.

Q. Is the Company projecting any changes to headcounts from the FTY to the FPFTY?

A. No. The headcount remains at 798 for the FPFTY and reflects increases relating only to an average annual wage increase of 3%.

Forecasted Non-Labor Expenses

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 normal, ongoing level of expenses and further adjusted for incremental activities or events that are reasonably expected to occur, or adjusted for expenses that are not expected to recur.

The FTY and the FPFTY outside Services budgets reflect planned work activities and work volume based on historical information and inflationary cost increases.

Corporate Level Budgets

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. Corporate insurance expenses are based on estimated property and casualty premium costs developed by NCSC's Insurance Department. Audit fees are based on estimates developed by NCSC Accounting. Telecommunications expenses are based on estimates developed by NCSC Information Technology. NCSC 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 budget. Benefits administration fees and incentive plan expenses are based on estimates developed by NCSC's Human Resources.

Q. Can you describe the NCSC annual budget development process?

The NCSC budget development process, with regard to timing and duration, is consistent with the Columbia planning process. The NCSC budget process used to develop the FTY and FPFTY was initiated in the fall of 2020 and completed in the first quarter of January 2021.

Targets for the NCSC functions are grounded in a trailing 12 month historical spend with merit and inflation adjusted for each year thereafter. The 12 month historical spend is adjusted to account for one-time items, future planned work, or strategic initiatives to develop final targets. Once targets are established, budgeted expenses are delineated by cost categories such as labor, materials, outside services, and other expenses.

NCSC's Vice President of Planning and Analysis reviews the completed budgets for reasonableness and an understanding of material changes for both the whole of the budgets and the allocation to each of the operating companies. The NCSC Service Fee is distributed to each operating company as an input to their planning process upon approval from NCSC's Vice President of Financial Planning and Analysis.

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 historical distributions to each operating company and adjusted as necessary for any one-time items, future planned work, or strategic initiatives as noted above. The resulting allocation is used to distribute costs by operating company in the financial plan.

In addition to the expenses mentioned above, each department is allocated a portion of NCSC's indirect costs, such as benefits, taxes, depreciation, and other expenses to arrive at a total cost. Labor is the primary driver of how the overhead costs are distributed to the departments. Please refer to Exhibit 4, Schedule 11, Attachment B's Exhibit A, for the description of the Direct Billing and Bases of Allocation for NCSC costs.

Q. Is the budget reviewed throughout the year?

A. Yes, on a monthly basis an analysis that compares budget to actual results is completed and reviewed. This analysis provides key drivers for variances for both monthly and year to date results. In addition to monthly variance analysis, present estimate updates are conducted with function/department leaders that provide forecast updates for the current year and any impact to future years.

O&M Expense Levels

Q. What are the O&M expense levels for the Historic Test Year, Future Test Year, and Fully Projected Future Test Year?

A. Per Exhibit 104, Schedule 1, Pages 3 & 4, Row 22, O&M expense is $155,861,629 for the Historic Test Year ended November 30, 2020, $185,363,000 for the Future Test Year ending November 30, 2021 and $188,548,000 for the Fully Projected Future Test Year ending December 31, 2022, increases of $29,501,371 and $3,185,000, respectively, before pro forma ratemaking adjustments for the FTY and the FPFTY.[1]

Q. Does this complete your direct testimony?

A. Yes, it does.

[1] This testimony compares O&M expenses independent of expense items specifically tracked against revenues as discussed earlier in this testimony.

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	A	C	D	E	F	G	H	I	J	K	L	M	N
6		Budget											
7	CE	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8	Labor	23,873	23,108	22,910	23,693	25,709	25,251	28,309	29,646	31,181	31,534	32,271	36,572
9	Incentive Compensation	293	1,171	1,149	1,249	1,238	1,333	1,584	1,642	1,742	2,150	1,133	2,676
10	Pension	2,119	6,005	6,598	-	3	1,137	-	6	549	-	-	
11	OPEB	715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)	(678)
12	Other Employee Benefits	5,076	6,363	6,509	6,184	6,454	4,584	4,791	5,635	5,975	6,445	6,851	7,302
13	Outside Services	15,636	15,175	13,094	12,123	12,104	22,311	26,079	23,977	25,458	22,634	23,453	22,167
14	Rent and Leases	1,314	1,374	1,458	1,615	1,887	2,273	4,791	3,607	3,873	3,203	3,296	2,857
15	Corporate Insurance	3,116	3,574	3,413	3,048	3,004	3,087	4,516	3,481	3,705	3,495	3,631	5,861
16	Injuries and Damages	1,209	944	795	630	630	500	500	400	-	400	400	400
17	Employee Expenses	1,109	1,046	1,163	1,142	1,295	1,305	1,640	1,452	1,501	1,584	1,483	1,642
18	Company Memberships	347	345	249	292	262	256	256	332	491	491	563	560
19	Utilities and Fuel Used in Company Operations	675	570	567	503	1,167	1,303	1,310	1,370	1,102	1,709	1,715	2,142
20	Advertising	500	185	170	170	470	170	170	170	170	170	174	174
21	Fleet	4,663	4,104	4,421	5,046	5,452	5,708	5,728	5,797	5,879	6,255	5,673	6,671
22	Materials & Supplies	4,929	4,767	4,775	4,899	4,649	5,024	5,067	5,962	5,366	5,865	5,568	5,755
23	Other O&M	(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381	193
24	PUC, OCA, OSBA Fees	1,673	1,953	1,354	1,454	1,699	1,583	2,161	2,330	2,460	2,262	2,341	2,262
25	NCSC Shared Services & NGD Shared Operations	31,889	38,399	37,740	39,742	44,597	47,962	49,533	57,719	67,158	66,049	64,185	59,051
26	Amortization	82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845	935
27	Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**	95,231	106,443	106,498	99,407	108,941	121,516	134,890	143,604	157,656	154,193	154,233	156,541

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	Actuals											
CE	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Labor	23,153	23,577	22,845	23,996	25,124	25,818	27,980	29,093	30,019	32,461	36,471	36,293
Incentive Compensation	1,303	1,628	1,649	1,690	1,845	1,816	1,791	1,981	2,590	1,381	1,246	2,137
Pension	392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12	13
OPEB	1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)	(693)
Other Employee Benefits	4,995	7,472	6,210	5,880	5,635	5,432	5,992	5,924	6,099	6,015	6,931	9,181
Outside Services	15,180	15,440	13,244	12,133	14,113	22,070	22,951	25,361	28,246	21,352	22,850	15,615
Rent and Leases	1,306	1,207	1,348	1,485	1,699	1,699	2,252	2,831	3,453	3,234	3,409	2,592
Corporate Insurance	3,045	3,241	2,926	2,763	2,734	2,796	2,899	3,024	3,176	3,239	4,363	6,281
Injuries and Damages	605	545	340	241	305	(185)	381	363	337	270	512	317
Employee Expenses	1,405	1,450	1,553	1,465	1,376	1,264	1,415	1,381	1,545	1,383	1,713	1,063
Company Memberships	295	250	293	262	249	313	479	563	599	527	569	854
Utilities and Fuel Used in Company Operations	451	417	487	1,094	1,247	1,244	1,287	1,460	1,679	1,693	1,723	1,871
Advertising	389	281	167	133	243	236	207	226	283	146	224	719
Fleet	4,650	4,726	5,092	5,357	5,780	6,106	5,956	6,206	6,320	6,338	6,906	6,389
Materials & Supplies	4,741	4,967	4,412	4,353	5,171	5,343	5,873	5,461	6,327	5,627	6,320	6,643
Other O&M	(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242	982
PUC, OCA, OSBA Fees	1,721	1,539	1,348	1,523	1,585	1,815	2,161	1,960	1,846	1,814	2,113	2,125
NCSC Shared Services & NGD Shared Operations	34,023	36,457	38,899	40,164	43,374	50,760	53,169	56,264	68,727	63,166	64,147	62,366
Amortization	82	0	(489)	(1,446)	(594)	185	267	396	511	845	845	935
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense	95,892	106,766	113,356	101,209	111,952	127,057	134,044	142,299	170,532	141,304	161,271	155,683

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	A	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN
1														
2														
3														
4														
5														
6									Variance					
7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor		(720)	469	(65)	303	(585)	567	(329)	(553)	(1,162)	927	4,200	(279)
9	Incentive Compensation		1,010	457	500	441	607	484	207	339	848	(769)	113	(539)
10	Pension		(1,727)	(206)	6,490	91	2,486	(6)	14	15	7,989	(8,417)	12	13
11	OPEB		968	(290)	(705)	242	(170)	(748)	42	227	104	266	405	(15)
12	Other Employee Benefits		(81)	1,109	(299)	(304)	(819)	848	1,201	289	124	(429)	80	1,879
13	Outside Services		(456)	265	150	10	2,009	(241)	(3,128)	1,384	2,788	(1,282)	(603)	(6,552)
14	Rent and Leases		(8)	(167)	(110)	(130)	(188)	(574)	(2,539)	(776)	(420)	31	113	(266)
15	Corporate Insurance		(71)	(333)	(487)	(285)	(270)	(291)	(1,617)	(457)	(529)	(255)	732	420
16	Injuries and Damages		(604)	(399)	(455)	(389)	(325)	(685)	(119)	(37)	337	(130)	112	(83)
17	Employee Expenses		296	404	390	323	81	(41)	(225)	(71)	44	(202)	230	(578)
18	Company Memberships		(52)	(95)	44	(30)	(13)	57	223	231	108	35	6	294
19	Utilities and Fuel Used in Company Operations		(224)	(153)	(80)	591	80	(59)	(23)	90	577	(16)	8	(272)
20	Advertising		(111)	96	(3)	(37)	(227)	66	37	56	113	(24)	51	546
21	Fleet		(13)	622	671	311	328	398	228	409	441	83	1,233	(283)
22	Materials & Supplies		(188)	200	(363)	(546)	522	319	806	(501)	961	(238)	752	889
23	Other O&M		460	774	272	720	(29)	2,418	740	(26)	(403)	428	(139)	788
24	PUC, OCA, OSBA Fees		48	(413)	(5)	69	(114)	232	-	(370)	(614)	(448)	(228)	(137)
25	NCSC Shared Services & NGD Shared Operations		2,134	(1,942)	1,159	422	(1,223)	2,798	3,636	(1,455)	1,569	(2,884)	(38)	3,315
26	Amortization		(0)	(74)	(246)	(0)	861	-	-	(100)	-	436	-	0
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		661	324	6,858	1,802	3,011	5,542	(846)	(1,305)	12,876	(12,889)	7,038	(858)
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COLUMBIA STATEMENT NO. 9-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

July 14, 2021

I. Introduction

Q. Please state your name and business address.

A. Nicole M. 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. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to portions of the direct testimonies of witnesses Crist filed on behalf of the Pennsylvania State University ("PSU"), Zalesky filed on behalf of the Bureau of Investigation and Enforcement ("I&E"), and Effron filed on behalf of the Office of Consumer Advocate ("OCA").

Q. How will your rebuttal testimony be organized?

A. I will discuss the following topics: Columbia's use of its Distribution System Improvement Charge ("DSIC"), O&M Adjustments and Observations offered by other parties' witnesses and my revisions. I will address the testimony of each of the witnesses listed above as they relate to those topics.

DSIC

Q. What testimony regarding DSIC will you discuss?

A. Mr. Crist, beginning at page 5 of his testimony, references Columbia's initial DSIC filing at Docket P-2012-2338282, and asserts that in that filing the Company "claimed that if a DSIC were in place there would be a reduced need to file base rate cases."

Q. Are there statements in Mr. Crist's testimony regarding the DSIC that you would like to discuss?

A. Yes, there are several. First, I have reviewed the Company's filing at Docket No. R-2012-2338282, and have been unable to identify any assertion by Columbia that the DSIC would reduce the frequency of the Company's rate filings. Further, in 2016, Columbia filed a request with the Commission to increase the 5% rate cap under the DSIC, arguing that the cap could not support even a single year of DSIC-eligible plant investment by Columbia. The Commission denied the requested increase to the rate cap, concluding in part that an increase was unnecessary because "the Company effectively utilized base rate cases including the FPFTY to adequately address its main replacement efforts." Petition of Columbia Gas, Docket No. P-2016-2521993, Order entered December 22, 2016, at page 50. On page 6, beginning at line 6 of his testimony, Mr. Crist states that "in this case the DSIC amount would be $28.3 million." This appears to be the mathematical application of 5.0% to the proposed distribution (non-gas) revenue of $564,684,366. Mr. Crist compares the $28.3 million to the initial requested revenue requirement increase in this case of $98.3 million, seemingly to suggest that using a DSIC could have replaced the outcome of the rate case.

Q. Are there any flaws in this proposition?

A. Yes. The DSIC can only be applied to actual base rates, not proposed base rates. So initially, the reference to $564,684,366 is an incorrect starting place. If Columbia were to have utilized a DSIC in place of this base rate proceeding, the 5% would have been applied to existing base rate revenues of $470,931,984 (Exhibit 103, Schedule 8, page 1) less approximately $4.9 million for those customers not billed the DSIC, yielding only $23.4 million, not $28.3 million.

Q. What portion of projected 2022 investment could be recovered through a DSIC had it been utilized instead of the instant proceeding?

A. The last time the Company used the DSIC was in 2020. Columbia cannot charge the DSIC until its applicable plant investment exceeds that included in its recently concluded 2020 rate case. I note that Columbia's projected 2021 plant additions exceed those reflected in the Commission's 2020 Order. Therefore, had the instant proceeding not been filed, as Mr. Crist appears to suggest, the DSIC rate would likely be used, in part, to recover 2021 investment. Even if the full DSIC cap were available to use for 2022 investments, a cap of $16.3 Million would only support $194 Million in plant investments, at the 9.86% return on equity authorized in Columbia's 2020 rate case. See Exhibit NP-1R for the supporting calculation. This is well short of the $324.5 Million in projected 2022 capital investment claimed by Columbia in this case. This also fails to consider increases in expenses that can only be recovered in a base rate case. Mr. Crist's statement that "having a DSIC provides Columbia the ability to receive revenue of a similar magnitude as what it may receive in this case" is fundamentally incorrect.

II. O&M Adjustments and Observations

Q. Please summarize the items you will be addressing regarding other parties positions and adjustments to the Company's claim for O&M Expenses in the FPFTY.

A. I will be addressing budgetary issues resulting in proposed reductions to the Company's FPFTY revenue requirement. To the extent that such reductions are proposed as a result of rejection of the use of the FPFTY, I will be addressing that issue as well.

Q. Would you now address the specific adjustments that Mr. Effron proposes to O&M expense in his calculation of a Revenue Requirement?

A. Yes. Mr. Effron has proposed a decrease in labor expense of $1,076,000 and a decrease of $306,000 to other employee benefit expenses associated with a reduction of 29 of the incremental 31 employees planned to be hired in the FTY. He based the elimination on the fact that total headcount on a monthly basis peaked at 769 in April 2021, exclusive of two public affairs specialists Mr. Effron incorrectly classifies as providing services "akin to lobbying". I will specifically address this issue later in my testimony.

Q. Do you agree with Mr. Effron's proposed adjustments to the Company's labor expense?

A. No. All proposed adjustments to labor and corresponding impacts to Employee Benefit expense should be rejected.

Q. Do you agree with Mr. Effron's proposed headcount reduction?

A. No. Current Company headcount as of June 28, 2021 is 774 employees, 5 higher than in April 2021, as referenced by Witness Effron in his proposed adjustment. Further, as a result of the wave hiring process that is explained at page 10 of my direct testimony, 15 applicants have accepted positions offered and are currently going through standard company procedures surrounding the hiring process. Assuming all applicants meet Company requirements, Company headcount has increased to 789.

Q. Should a reduction in headcount be made, does the Company have an alternative calculation to offer?

A. Yes. It should be noted that in calculating his headcount adjustment, Witness Effron utilizes projected employees of 798 for the FPFTY based on the Company's original response to standard data requests GAS RR 26. GAS RR 26 Revised, attached to my testimony as Exhibit NP-2R has a headcount of 811. Therefore, the Company has demonstrated that the wave hiring that will take place in August and October will take the Company to the full complement of employees in the case.

However, should a headcount adjustment be made, the adjustment should be adjusted based on 789 employees, not 769. Using Mr. Effron's labor adjustment methodology, this would reduce his labor and employee benefits adjustments to $814,000 and $231,000, respectively (see calculation below).

Labor Expense	
Forecasted Employees	811
Employees June 28	789
	22
O & M Labor Expense	37,000
Revised Labor Adjustment	814,000
Benefits Expense	
Other Employee Benefit Expense	10500
Employee Adjustment	22
Revised Benefits Adjustment	231,000

Q. What are the Company's plans for wave hiring for the remainder of 2021?

A. The Company is currently in the wave hiring process, and plans two more additional waves of employees in August and October 2021. Per page 10 of my direct testimony at Columbia Statement No. 9, hiring was to take place in June, however, as a result of hiring system maintenance, the hiring process was pushed back until August. Assuming the same number of employees are hired in the next two waves, the Company will easily meet the full complement of 811 employees per its revised response to standard data request GAS RR-26.

Q. What other issues does Witness Effron fail to take into consideration in proposing a headcount reduction of 29 employees?

A. Mr. Effron fails to consider that the Company continues to fill a number of the incremental positions to support its ongoing operational activities to provide safe, reliable service to customers. These positions are most often filled from within the

Company's existing employee ranks and bargaining unit agreement provisions can affect the bidding and selection process so that vacancies are held open for certain periods while applicants temporarily occupy a position before making a final decision. Once the new positions are filled by existing employees, the employees' former positions are then filled by new hires. Furthermore, and more significantly, budgeted labor expenses are driven largely by the Field Operations Work Plan and, to the extent that vacancies do impact the availability of Full Time Employee equivalents ("FTEs"), the work will be accomplished via overtime or the use of contracted labor recorded in Outside Services.

Q. Please explain the roles of the Public Affairs specialists that Witness Effron classifies as "lobbying".

A. His classification is incorrect. The Company's response to data request OCA 4-2, attached to my testimony as Exhibit NP 3-R clearly details the responsibilities of the Public Affairs employees. The primary role of those employees is to help educate municipalities where the Company works and conducts significant pipeline replacement projects. Exhibit NP 3-R clearly explains how the roles of the Public Affairs specialists impact the Company's ongoing infrastructure replacement program. As indicated in the response, the Public Affairs employees work with municipalities to control costs that will be incurred by Columbia for its mains replacement program. This provides a direct benefit to Columbia's customers, as explained at pages 15-24 of Columbia witness Brumley's direct testimony. The assertion that such costs are lobbying costs is erroneous, and Witness Effron's proposal to remove the salaries of these employees from the Company's labor expense should be rejected.

Q. Does Witness Effron propose any additional adjustments to Labor Expense?

A. Yes, Witness Effron proposes to eliminate $87,000, referencing the Company's response to standard data request GAS-RR-026 REVISED, Attachment A, "Other Adjustments" amounts in Columns (9) and (16), based upon his assertion that these adjustments lack any substantive support.

Q. Do you agree with this adjustment?

A. No, I do not. The presentation of Labor in GAS-RR-026 REVISED is meant to provide a high level view of adjustments to labor, spanning across the test periods for this case. The Company's actual method of determining Labor Expense is done at a much more granular level and, when determining the presentation for GAS-RR-026 REVISED, the Company attempts to break out the main drivers of change. Consequently, the Adjustments in Columns (9) and (16) are needed to accurately tie out Labor Expense amounts to the total Labor Budget amounts in columns (10) and (17). The amounts in Columns (10) and (17) match the Budgeted Labor as presented in Exhibit 104, Schedule 1, Pages 5 and 6.

Q. What adjustment does Witness Effron propose to Incentive Compensation expense?

A. Witness Effron proposes a downward adjustment of $810,000 to the Company's claim for Incentive Compensation expense associated with Columbia employees in the FPFTY. He bases the adjustment on the ratio of Incentive Compensation to total Labor expense in the HTY. Once again, his proposal reverts to the use of historical ratemaking principles rather than the use of a FPFTY which is the basis for this case and the past five base rate cases that the Company has filed. His adjustment was calculated per the table below.

TME 11/30/2020	
Labor Expense	38,012,527
Accrued Incentive Compensation	1,566,381
% Incentive Compensation to Payroll Expense	4.12%
FPFTY Labor Expense	39,678,280
Proposed Incentive Compensation	1,635,000
FPFTY Incentive Compensation	2,445,000
Proposed Disallowance	(810,000)

Q. **Do you agree with the adjustment?**

A. No. Incentive Compensation awards are based on many factors, as described in the Plan documents included as Attachment D to the Company's response to standard data request GAS-RR-027 filed with the case and in Company Witness Cartella's Rebuttal testimony (Columbia Statement No. 15-R). While the Company's annual budget projects Incentive Program expense calculated on the anticipated base salary of employees during the period and the assumption of achieving the target performance levels described in the Incentive Plan, actual Incentive Compensation can be awarded at, above, or below target corresponding to actual results. Looking at one point in time that was at a payout rate below target level does not provide a basis to qualify a projection as unreasonable (I&E witness Mr. Zalesky also suggests an adjustment based on historical data which I address later in my testimony.) Further, in determining the payroll to incentive compensation ratio, Witness Effron utilized the accrued incentive compensation expense, as opposed to the actual payout for incentive compensation expenses, the latter of which more accurately reflects incentive compensation. The table below update reflects the impact to the proposed adjustment, had actual payout been used:

TME 11/30/2020	
Labor Expense	38,012,527
Incentive Compensation Payout	1,634,650
% Incentive Compensation to Payroll Expense	4.30%
FPFTY Labor Expense	39,678,280
Proposed Incentive Compensation	1,706,000
FPFTY Incentive Compensation	2,445,000
Proposed Disallowance	(739,000)

Q. If an adjustment is made to incentive compensation, does the Company have an alternative calculation to offer?

A. The Company rejects Witness Effron's proposal because his proposal reverts to the use of historical ratemaking principles rather than the use of a FPFTY and only looks at a single point in time. However, if an adjustment is to be made, the Company offers the calculation below as a proposed alternative.

Period	CPA Labor Expense	CPA Incentive Compensation Payouts
TME 11/30/2018	32,215,808	2,596,029
TME 11/30/2019	36,130,190	1,446,531
TME 11/30/2020	38,012,527	1,634,650
Total	106,358,525	5,677,210
Three Year Average Labor Expense	35,452,842	1,892,403
Three Year Average Incentive Compensation Payouts	1,892,403	
% Incentive Compensation to Payroll Expense	5.34%	
FPFTY Labor Expense	39,678,280	
Proposed Incentive Cmpenation	2,117,949	
FPFTY Incentive Compensation	2,445,000	
Difference	327,051	

Q. What adjustments does Mr. Effron propose to the Company's claim for Outside Services Expense in the FPFTY?

A. Witness Effron proposes to adjust Outside Services by $4.3 Million, citing lack of support for proposed increases. To calculate his adjustment, Witness Effron utilized actual outside services for the twelve months ended November 2018 and 2019, and used the Company's escalation factors to escalate the average of those expenses to the HTY to establish a normalized level for the HTY. He further escalated the amount to the FPFTY. His calculation is shown below:

Period		CPA
TME 11/30/2018		23,171,000
TME 11/30/2019		23,768,000
Average		23,469,500
Escalation - FTY	1.64%	23,854,000
Escalation - FPFTYTY	1.85%	24,295,000
Less: Lobbying Expense		(165,000)
Normalized FPFTY Outisde Services Expense		24,130,000
Company FPFTY Outside Serices Expense		28,437,000
Proposed Adjustment to Outside Services Expense		(4,307,000)

Q. What detail has previously been provided to support Outside Services?

A. The Company responded to multiple data requests for information regarding outside services. The response to OCA 1-36, which requested an itemization of costs from the HTY to the FTY is included herein as Exhibit NP-4R. Responses to OCA 1-37 and OCA 1-38, attached to my rebuttal testimony as Exhibits NP-5R and NP-6R, respectively, provide supporting information for increases in the budget by line item from the HTY to the FTY and the FTY to the FPFTY. The Company's response to I&E RE 70, attached to my rebuttal testimony as Exhibit NP-7R, provides updated information on actual spend for items included in OCA 1-36 and the reason for the budgeted increase. The Company believed that adequate information had been provided for outside services, and answered data request OCA 8-8, attached to my rebuttal testimony as Exhibit NP-8R accordingly.

Q. In light of Witness Effron's assertion that the Company has not provided

sufficient reasons supporting the increase, does the Company have additional detail available to address his concern?

A. Yes. Please see Exhibit NP-9R for further detail. I note that several of these FPFTY increases over HTY levels (replacement of customer-owned risers, GPS Legacy Records Program and accelerated cross-bore repair) were issues in Columbia's 2020 rate case. In that case, the Commission accepted increases to implement these important safety-related initiatives to begin in the FPFTY in that case, which is calendar year 2021.

Q. Do you agree with Mr. Effron's recommendation regarding Outside Services?

A. No. As noted earlier in my rebuttal testimony, Mr. Effron is rejecting the basis of a FPFTY. For all cost categories, the Company uses its best estimate of the work to be performed, services to be secured and the costs anticipated to accomplish that work during the FPFTY. Pages 7, 8 and 9 of Exhibit NP-5R and pages 6-7 of my direct testimony show that the Company's budgets have historically been a very good indicator of actual costs. Because the Company continually reviews budget variances throughout the year, it is able to identify differences in order to adjust spending including, where appropriate, increased spending on certain projects where spending is expected to fall below budget for the year. As my direct testimony explains, Columbia's budget process is a conservative approach, as actual spending has exceeded budget in eight of the past eleven years. Additionally, this is the sixth base rate proceeding in which the Company has based its claim on the forward looking budget.

Specifically, the Outside Services budget is estimated with expectations around discrete work streams and operational programs. It also can be utilized to address unforeseen operational circumstances, to supplement internal resources as needed and to balance the work plan accordingly. The budget for Outside Services is developed reflective of specific needs, plans and the realities of the day to day variability in work and resources.

Q. Please describe the adjustments that Witness Effron proposes to the Company's claim for NiSource Corporate Service Company ("NCSC") expenses.

A. Witness Effron is proposing a blanket reduction to the NCSC expense in the amount of $14,959,000. To calculate his adjustment, he utilizes the percentage increase in total NCSC expenses between 2019 and 2021, as shown in the Company's response to data request OCA 1-37, attached to my rebuttal testimony as Exhibit NP-5R, to determine the amount to be recovered. He further incorrectly asserts the Company has not provided adequate support for the increases in NCSC expense.

Q. Do you agree with Witness Effron's recommendation?

A. No. Not only does Witness Effron's proposal once again revert to the use of historical ratemaking principles rather than the use of a FPFTY, which is the basis for this case and the past six base rate cases that the Company has filed, he fails to recognize that

Columbia Gas of Pennsylvania is still receiving the benefit of services from NiSource Corporate Services at a cost favorable to such services had they been procured outside of the Company. Finally, a significant amount of support for the increases related to NCSC expense and safety plan expense has been provided, which I will discuss later in my rebuttal testimony.

Q. What are the primary drivers for the increase in NCSC expenses?

A. The primary drivers for the increases are the result of an increase in the percentage of costs allocated to Columbia Gas of Pennsylvania for support services subsequent to NiSource's sale of Columbia Gas of Massachusetts, as well as incremental expenses related to the Company's safety programs. The nature of the services received from NCSC are described in the Affiliated Interest Agreement between NiSource Corporate Services and Columbia Gas of Pennsylvania. A copy of the Commission approved agreement has been attached to my rebuttal testimony as Exhibit NP-10R.

Q. What is wrong with Mr. Effron's focus on Columbia Gas of Pennsylvania's higher allocation of NCSC costs subsequent to the sale of Columbia Gas of Massachusetts?

A. As a public utility, the Company's responsibility is to provide safe, reliable gas service to our customers at reasonable and prudent costs. The notion that increased NCSC costs are not prudent because of the sale of Columbia Gas of Massachusetts does not take into consideration whether such costs from services provided by NCSC are reasonable compared to similar services provided by an outside third party.

Q. Are the costs for services provided by NCSC reasonable and prudent?

A. Yes, they are. For a detailed analysis that supports the reasonableness and prudency of those costs, I refer you the rebuttal testimony of Columbia witness Patrick Baryenbruch, Columbia Statement 16-R.

Q. Does NCSC update cost factors to ensure that allocations are accurate?

A. Yes. Allocations are updated twice a year, based on the 12 months ending June 30 and December 31. New allocations go into effect in February and August.

Q. So, can allocations factors fluctuate based on the activity across all the NiSource Companies?

A. Yes.

Q. Is the underlying reason for the sale of Columbia Gas of Massachusetts relevant to this case?

A. It is not. The Company had no involvement in the incident in the Merrimack Valley, nor the circumstances under which Columbia Gas of Massachusetts was sold. What is relevant is that the customers of Columbia Gas of Pennsylvania are receiving services from NCSC at a cost that is below market, as required under the Commission approved contract between CPA and NCSC.

Q. Do you agree with Witness Effron that the Company has not provided adequate support for the increases in the NCSC allocation?

A. No. The Company's response to OCA 1-37, attached as Exhibit NP-5R, clearly shows how the increases in allocation factors were calculated. Mr. Effron's assertion that the

Company did not adequately support the increase is factually incorrect.

Q. Would you like to respond to Mr. Effron's observation that Columbia's allocated corporate services costs are lower for the first five months of 2021 than budgeted?

A. Yes, I would. Mr. Effron's observation, while accurate as it relates to the months of January through May, represents only a snapshot of the Company's corporate services charges for 2021.

Q. Please explain.

A. Mr. Effron inappropriately seeks to support a disallowance of Columbia's budgeted corporate service charges based solely on 5-months of actual data. Specifically, Mr. Effron fails to take into account the impact of timing differentials between the projected budget compared to actual spend, which for Columbia is more weighted towards the end of the year. Indeed, Mr. Effron seeks to support his proposed disallowance based upon a monthly run rate calculation that takes the average of the first 5 months of actual data and extrapolating that through November 2021. However, simply updating Mr. Effron's calculation with June year to date numbers, and including December 2020 actual data, Mr. Effron's run rate calculation results in the Company's corporate service costs at a $70.5M year-end target. This results in approximately $6.2M less than the budget of $76.6M for the future test year.

Q. Based upon this updated analysis, does Columbia expect that its corporate services costs will fall approximately $6.2M below its budget?

A. No. The Company expects to experience increases in the areas of safety, as well as expenses related to medical benefits and other employee benefits. Specifically, Columbia anticipates increases in the following areas:

- Approximately $4.7M of safety plan and safety services spend related to Training, Asset Risk Management, and the hiring timing for Quality Management System. These costs were spread evenly by month in the budget, but are expected to increase over the remainder of the year compared to the budget.
- Approximately$2M of indirect costs, primarily related to active medical/other benefits. This spend is currently less than expected due to employee behaviors of delaying optional medical treatment, and pandemic activity restrictions extending into the first half of 2021. Columbia's third party actuary, Aon Hewitt, indicates that this spend is likely t0 increase over the remaining months of the year and into 2022, reversing the favorability seen to date.

With the timing considerations of this spend compared to the budget, Columbia expects to end the financial period as projected based on known data at this time.

Q. Please describe the adjustments that Mr. Effron proposes to the Company's claim for Safety Initiatives.

A. Mr. Effron suggests that the Company has not provided enough information to support the Safety Initiatives. He does not make a specific recommendation for safety plans costs included in NCSC costs but, instead, suggests that such costs are not supported. He further makes a proposal to disallow $230,000 related to the System Viability Pressure Program.

Q. Does the Company have any updates to the Safety Costs included in NCSC costs?

A. Yes. Certain costs in the amount of $636,000 are related to electric safety initiatives and should not be included in the Company's revenue requirement. Such costs are detailed within Exhibit NP-11R, and the Company will adjust revenue requirement accordingly.

Q. Do you agree with Witness Effron that the Company has not provided adequate detail regarding safety initiatives?

A. No. In the Company's response to data request OCA 8-6, attached to my rebuttal testimony as Exhibit NP-12R, the Company clearly provides the information requested by Witness Effron.

Q. Witness Effron states in his testimony the Company does not provide information to determine how the expense increases were determined. Is the Company able to provide this information?

A. Yes. Further detail has been provided in Exhibit NP-11R. Exhibit NP-11R is an update to the Company's response to OCA 8-6, attached to my rebuttal testimony as Exhibit NP-12R, which clearly supports the increase as requested in the discovery request. Exhibit 11-R provides additional detail to contradict the notion in Witness Effron's testimony that increased costs for safety initiatives have not been supported.

Q. With respect to the $230,000 related to the System Viability Pressure Program, why is having replacement parts on hand critical to the

Company's safety protocol?

A. Columbia continues to focus its efforts and resources on risk mitigation. As an example, Columbia is actively engaged in reducing the risk of over-pressurization on its systems and regulator stations with the completion of the installation of automatic shut off valves on low pressure systems and SCADA monitoring equipment. SCADA monitoring provides real-time regulator station operating data and provides critical information when changing operating conditions occur, such as a spike in system pressure. Components or associated materials at these regulator stations may fail to function as designed, which would result in an emergency response to identify and correct the failed part or component. In these situations, a Columbia measurement and regulation technician must respond to troubleshoot and make the needed repairs with material that is readily available. Therefore, at SCADA-equipped regulator stations, Columbia intends to obtain the needed spare parts to complete repairs in a timely fashion. While it is impossible to predict precisely where and when a component may fail, it is necessary to keep parts on hand to facilitate timely repairs when required.

Q. Is Witness Effron correct in stating that such costs should be considered inventory, and therefore part of rate base?

A. Even if such costs were considered to be inventory, they would ultimately be expensed upon usage. For this reason, as well as the need to have spare parts on hand to facilitate the repair of equipment, Witness Effron's proposal should be rejected.

Q. Would you please now address the O&M adjustments proposed by I&E witness Zalesky beginning with his employee vacancy adjustment to Labor expense?

A. Mr. Zalesky gathered information from the Company's discovery responses and calculated a reduction to labor in the amount of $583,072 based on a 14 employee headcount reduction, using an average cost of payroll and benefits. I note that Mr. Zalesky proposes the adjustments to labor expense stated on Columbia's originally filed headcount of 798 in its response to Standard Data Request GAS-RR-026 rather than the headcount of 811 reflected in the revised response to GAS-RR-026 included herein as Exhibit NP-2R. As I discussed above in relations to Mr. Effron's proposed headcount reduction, Columbia has supported a headcount of 811 in the FTY and FPFTY in this case. Accordingly, Mr. Zalesky's proposed headcount reduction should be rejected.

Q. Please explain why you disagree with Witness Zalesky's proposed labor adjustment?

A. Budgeted Labor expense is largely driven by the Field Operations Work Plan and, to the extent that vacancies do impact available FTEs, the work will be accomplished via overtime or the use of contracted labor recorded in Outside Services. Stated otherwise, Mr. Zalesky's proposed adjustment assumes that if a position is vacant, work will not be performed. That is incorrect. The work will be performed, either by overtime or contracted labor. As stated on page 8 of my direct testimony, labor expense is based on projected headcount. The development of the Work Plan assumes that level of internal resources is available and balances the projections of overtime and contracted labor in Outside Services expense accordingly. As such, the proposed adjustment for labor should be rejected.

Furthermore, as I explained with respect to Mr. Effron's proposed labor adjustment, Mr. Zalesky's adjustment fails to take into account the Company's ongoing wave hiring. Counting the 15 applicants who have accepted positions, the Company's current headcount has increased to 789, which is more than the headcount used to derive Mr. Zalesky's adjustment.

Q. What adjustment did Witness Zalesky propose to employee benefit expense?

A. Witness Zaleksy asserts that the claim for employee benefits is unsupported, and proposes a reduction to employee benefit expense in the amount of $1,281,391 based on the three year average historical percentage of Other Employee Benefits to total labor expenses.

Q. Do you agree with that adjustment?

A. No. Witness Zalesky's reason for proposing this adjustment is that the claim is unsupported, and is based on results from an undisclosed third party consultant.

Q. Did the Company respond to data requests seeking support for the claim for Other Employee Benefits?

A. Yes. The Company's response to OCA 8-7, attached to my testimony as Exhibit NP-

13R, shows the information provided to the Company by our third party administrator in Attachment A. While Attachment A to the Company's response to OCA 8-7 does not directly indicate the information was provided by the Company's third party administrator, Aon Hewitt, Exhibit NP 14-R shows the email that the file was attached to, clearly from Aon Hewitt. Further, page 12 of my direct testimony clearly states other employee benefits expenses are provided by Aon Hewitt.

Q. What are the reasons for the increase in Other Employee Benefits?

A. Increases for Other Employee Benefit expense are based on Company headcount (Columbia Gas of Pennsylvania only). Headcount used for the 2021 and 2022 plan assumptions was 798, compared to previous plan assumption headcount of 724. In addition, the savings plan and profit sharing plan figures being 401k related will naturally increase with payroll increases (approximately 3%), in addition to any headcount increases. Lastly, medical costs have shown an increase as well, due to increased head count and continued rising costs of healthcare.

Q. What adjustment does Mr. Zalesky propose with regard to Incentive Compensation?

A. Mr. Zalesky proposes a downward adjustment in the amount of $925,097 for Company employees, and a $782,759 downward adjustment for NSCS employees to the Incentive Compensation expense claim (and a corresponding Payroll Tax adjustment).

Q. How does Witness Zalesky calculate his proposed allowance for the

Company's incentive compensation?

A. See the table below for Witness Zalesky's calculation.

Period	CPA Accrued Incentive Compensation Expense
TME 11/30/2018	1,521,149
TME 11/30/2019	1,472,179
TME 11/30/2020	1,566,381
Total	4,559,709
Average	1,519,903

The calculation is based on a three year average of accrued incentive compensation, which Mr. Zalesky incorrectly described as "payouts" in his testimony.

Q. What would the impact to the Company's proposed allowance for incentive compensation be, if an adjustment were to be made based upon average payouts, rather than the average accrued expense that Mr. Zalesky's employed in his calculation?

A. See the table below.

Period	CPA Incentive Compensation Payouts
TME 11/30/2018	2,596,029
TME 11/30/2019	1,446,531
TME 11/30/2020	1,634,650
Total	5,677,210
Average	1,892,403

This average is $372,500 greater than that used to derive Mr. Zalesky's adjustment.

Q. What do you recommend with regard to Mr. Zalesky's proposed

adjustment to Incentive Compensation?

A. I recommend that Mr. Zalesky's adjustment be rejected as it is based on accrued compensation expense and not on actual payouts. While the FPFTY budget is higher than the three year average of payouts, it should be noted that incentive compensation expense is budgeted for payment at the target level, but may not always be paid at the target level.

Q. How does Witness Zalesky calculate his proposed allowance for NCSC incentive compensation?

A. See the table below for Witness Zalesky's calculation.

Period	NCSC Accrued Incentive Compensation Expense
TME 11/30/2018	2,509,880
TME 11/30/2019	1,729,947
TME 11/30/2020	63,025
Total	4,302,852
Average	1,434,284

Consistent with his proposed adjustment for Columbia Gas of Pennsylvania employee's incentive compensation, his calculation is based on a three year average of accrued incentive compensation, which he incorrectly describes as "payouts" in his testimony.

Q. What would the impact to the Company's proposed allowance be if an adjustment were to be made based upon average payouts, rather than accrued expense?

A. See the table below.

Period	NCSC Incentive Compensation Payouts
TME 11/30/2018	4,322,369
TME 11/30/2019	1,923,221
TME 11/30/2020	2,166,277
Total	8,411,867
Average	2,803,956

This average is $1,360,674 greater than that used to derive Mr. Zalesky's adjustment.

Q. What do you recommend with regard to Mr. Zalesky's proposed adjustment to Incentive Compensation?

A. I recommend that Mr. Zalesky's adjustment be rejected since the three year average of incentive compensation payouts exceeds his adjustment.

Q. Mr. Zalesky proposes to reduce the Company's claim for PUC/OCA/OSBA fees to reflect the assessment for 2020. Do you agree with that recommendation?

A. The Company proposes that costs associated with PUC fees be updated upon receipt of the most current invoice. Such invoices are generally received in the September time frame.

Q. Do any other witnesses have comments regarding the Company's O&M claim that you would like to address?

A. Yes. PSU witness Mr. Crist makes a general observation that pro forma reductions should have been made to costs for reduced gas leaks, better gas control, reduced labor and maintenance costs and other benefits that he presumes would be produced by the Company's capital investment, but observes that the O&M in this proceeding is greater than the level in the 2020 case.

Q. Does Mr. Crist present any evidence that such savings have or have not been achieved or forecasted in those areas, or quantify any recommended specific reductions to the Company's claim?

A. No. Therefore, without specifics to address, I recommend that his general statement be dismissed. Moreover, as Columbia witness Brumley has explained on page 11 of his direct testimony (Columbia Statement No. 7), the impact of the replacement on system leakage will be gradual over the term of the replacement program as the remaining inventory of bare steel and cast iron pipe to be replaced, while decreasing, continues to age, degrade and drive leak repair activities. Also, costs associated with leak repair represent only a fraction of the Company's annual O&M costs. Furthermore, operating costs continue to increase due to factors such as wage increases, inflation and more stringent regulatory safety requirements.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania
DSIC Modeling
Prepared: June 2021

Revenue Requirement and Surcharge Calc

	Description		Surcharge Effective April 1, 2022	Surcharge Effective July 1, 2022	Surcharge Effective October 1, 2022	Surcharge Effective January 1, 2023
1	Applicable Additions		$ 42,859,338	$ 117,463,971	$ 204,695,402	$ 279,568,101
2	Less: Accumulated Depreciation		$ 267,309	$ 999,920	$ 2,276,584	$ 4,020,221
3	**Net Rate Base Included in DSIC (Ln 1 - Ln 2)**	**DSI**	$ 42,592,029	$ 116,464,051	$ 202,418,818	$ 275,547,880
4	Annual Revenue Requirement Rate		9.45%	9.45%	9.45%	9.45%
5	Quarterly Revenue Requirement Rate **(Ln 4 / 4)**	**PTRR**	2.36%	2.36%	2.36%	2.36%
6	Quarterly Capital Cost Recovery **(Ln 5 * Ln 3)**	**DSI X PTRR**	$ 1,005,172	$ 2,748,552	$ 4,777,084	$ 6,502,930
7	Quarterly Depreciation Expense		$ 267,309	$ 732,611	$ 1,276,664	$ 1,743,637
8	Quarterly DSIC Costs to be Recovered **(Ln 6 + Ln 7)**		$ 1,272,481	$ 3,481,163	$ 6,053,748	$ 8,246,567
9	Quarterly Base Distribution Revenues	**PQR**	$ 116,220,907	$ 116,220,907	$ 116,220,907	$ 116,220,907
10	Distribution System Improvement Charge **((Ln 8) /Ln 9)**	**DSIC**	**1.09%**	**3.00%**	**5.21%**	**7.10%**

$ 196,446,177	$ 196,871,857	[1]	
$ 2,184,838	$ 2,831,040	[1]	
$ 194,261,340	$ 194,040,817		$ 194,040,817
9.45%	9.45%		
2.36%	2.36%		
$ 4,584,568	$ 4,579,363		
$ 1,225,214	$ 1,227,869	[1]	
$ 5,809,782	$ 5,807,232		$ 16,370,659
$ 116,220,907	$ 116,220,907		
5.00%	**5.00%**	[2]	
95.97%	70.42%		

[1] Amount calculated by taking 95.97% for 3rd quarter and 70.42% for 4th quarter (5.0% cap divided by 5.21% for Q3 and 7.10% for Q4 pre cap rate) of calculated surcharge (pre 5% cap) for additions, accumulated depreciati

[2] DSIC is capped at 5.0% of the amount billed to customers for distribution services on an annualized basis.

on, and depreciation expense.

Description	Pre-HTY TME 11/30/2019	HTY TME 11/30/2020	Budgeted Vacancies	Ni Next Headcount Adj	FTY TME 11/30/2021	FPFTY TME 12/31/2022
Employees						
Total Clerical Labor	90	95	0	0	95	95
Total Exempt Labor	167	174	19	(3)	190	190
Total Manual - Non-Union	14	15	4	0	19	19
Total Manual - Union	492	483	24	0	507	507
Total Employees	763	767	47	(3)	811	811

Description b.,c.,d., and e	Pre-HTY TME 11/30/2019	HTY TME 11/30/2020 Per Books	Rate Making Adjustments	HTY TME 11/30/2020 Normalized	Budgeted Vacancies	NiNext Savings	Wage Increase @ 3%	Cap/O&M Change	Other	FTY Budget	Rate Making Adjustments	FTY TME 11/30/2021 Normalized	Wage Increase @ 3%	NiNext Savings	Cap/O&M Change	Other	FPFTY Budget	Rate Making Adjustments	FPFTY TME 12/31/2022 Normalized
	(1)	(2)	(3)	(4)=(2)+(3)	(5)	(7)	(6)	(8)	(9)	(10)=Sum (4 through 9)	(11)	(12)=(10) + (11)	(13)	(14)	(15)	(16)	(17)=Sum(12 through 16)	(18)	(19)=(17) + (18)
Payroll Expense																			
Regular Payroll	31,713,297	**31,788,065**	1,628,705	33,416,770	1,957,451	(807,212)	819,444	(1,598,968)	**334,273**	34,121,757	504,421	34,626,178	975,510	(594,394)	(108,522)	6,227	34,905,000	430,280	35,335,280
Overtime Payroll	4,362,259	**4,172,342**	-	4,172,342	-	-	-	-	**546,901**	4,719,243	-	4,719,243	-	-	-	(376,243)	4,343,000	-	4,343,000
Premium Payroll	58,413	222,632	-	222,632	-	-	-	-	(222,632)	-	-	-	-	-	-	-	-	-	-
Net Affiliate Labor Transferred	(3,779)	200,784	-	200,784	-	-	-	-	(200,784)	-	-	-	-	-	-	-	-	-	-
Total Expense	36,130,190	36,383,823	1,628,705	38,012,527	1,957,451	(807,212)	819,444	(1,598,968)	457,758	38,841,000	504,421	39,345,421	975,510	(594,394)	(108,522)	(370,016)	39,248,000	430,280	39,678,280
Capital Payroll																			
Regular Payroll	22,554,725	**27,159,006**	1,385,028	28,544,034	2,262,288	**486,409**	765,918	1,598,968	**227,939**	33,885,556	459,219	34,344,775	830,245	**485,197**	108,522	**(1,138,490)**	34,630,249	402,720	35,032,968
Overtime Payroll	3,277,396	**3,520,574**	-	3,520,574	-	-	-	-	**(1,072,519)**	2,448,055	-	2,448,055	-	-	-	(353,723)	2,094,332	-	2,094,332
Premium Payroll	43,886	187,854	-	187,854	-	-	-	-	(187,854)	-	-	0	-	-	-	-	-	-	-
Net Affiliate Labor Transferred	(2,840)	169,419	-	169,419	-	-	-	-	(169,419)	-	-	0	-	-	-	-	-	-	-
Total Capitalization	25,873,167	31,036,854	1,385,028	32,421,882	2,262,288	486,409	765,918	1,598,968	(1,201,854)	36,333,611	459,219	36,792,830	830,245	485,197	108,522	(1,492,213)	36,724,581	402,720	37,127,301
Total Payroll	**62,003,357**	**67,420,677**	**3,013,732**	**70,434,409**	**4,219,739**	**(320,803)**	**1,585,362**	**-**	**(744,096)**	**75,174,611**	**963,640**	**76,138,251**	**1,805,755**	**(109,197)**	**-**	**(1,862,228)**	**75,972,581**	**833,000**	**76,805,580**
Incentive Comp																			
Expense	1,472,179	260,629	1,640,296	1,900,925	-	-	-	-	462,075	2,363,000	-	2,363,000	-	-	-	82,000	2,445,000	-	2,445,000
Capital	1,131,161	199,737	909,593	1,109,330	-	-	-	-	1,101,670	2,211,000	-	2,211,000	-	-	-	101,000	2,312,000	-	2,312,000
Total Incentive Comp	**2,603,340**	**460,366**	**2,549,889**	**3,010,255**	**-**	**-**	**-**	**-**	**1,563,745**	**4,574,000**	**-**	**4,574,000**	**-**	**-**	**-**	**183,000**	**4,757,000**	**-**	**4,757,000**

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 4

Question No. OCA 4-002:

Referring to Statement No. 7, Pages 16-20, what are the annual costs of the municipal outreach program? The response should include all supporting documentation and workpapers.

Response:

The Company's Public Affairs team of three employees – the Manager of Municipal affairs and two Public Affairs Specialists – executes the proactive municipal outreach program to establish, improve and maintain relationships with municipal officials in communities where we work and where we will conduct significant pipeline replacement or new business projects. The team focuses on educating local staff/officials and elected representatives of boroughs, townships and cities/towns about the company and its focus of delivering reliable and safe natural gas to residents; our pipeline replacement and new business efforts in general; specific planned pipeline replacement or new business projects in their community; the benefits of our pipeline replacement or new business projects in their community; and the need for reasonable permit fees, inspection fees and restoration requirements.

The team reviews proposed or passed local public policies that may impact Columbia's proposed work. Specifically, the Public Affairs team monitors municipal ordinances and proposed amendments that may unreasonably increase paving restoration requirements, unreasonably increase permitting fees or place additional unreasonable fees for inspections, road openings or road degradation on the rate payers of Columbia Gas. This work is a portion of the overall responsibilities of the three employees.

The estimated annual cost of the municipal outreach program is $140,700 and is based on 50% of the yearly salaries of the two Public Affairs specialists and 60% of the yearly salary of the Manager of Municipal Affairs. The proportion of the salaries allocated to the municipal outreach program is based on the proportion of time these employees spend on activities directly related to municipal outreach (described above).

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-036:

Referring to Exhibit No. 104, Schedule 1, Page 2, please provide an itemization of costs included in Outside Services of $18,736,977 in the HTY and $27,377,979 in the FTY.

Response:

HTY amount consists of per books for the Twelve Months Ended November 30, 2020 of $19,532,270 less rate making adjustments for Rate Case Expense totaling $635,594 (Exhibit 4, Schedule 2, Page 25) and rate making adjustment for Lobbying Expense totaling $159,699 (Exhibit 4, Schedule 2, Page 8). Standard Data Request "SDR" GAS-RR-052 provides a detailed breakdown of per books amount. Note that SDR-GAS-RR-052 amount for the Twelve Months Ended totals $19,535,970 and inadvertently include $3,700 booked to FERC Account 426, which is not in O&M, but is instead booked below the line in Other Income and Expense. The correct total is the "per books" amount stated above of $19,532,270.

Budget adjustments for Outside Services totaling $8.6 million are listed below in table OCA-1-036.

TABLE OCA-1-036

Budget Increase over HTY	
Activity	**$Millions**
Maximum Allowable Operating Pressure	1.1
Customer Owned Risers *	1.3
Company Owned Risers*	1.2
PA Corrosion	0.2
GPS Legacy	0.7
Cross bore increase	1.4
Field Assembled Riser Increase	1.7
Right Of Way	0.5
Other	0.5
Total	**8.6**
* Increase is related to work delayed until 2021 as a result of COVID 19.	

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-037:

Referring to Exhibit No. 104, Schedule 1, Page 3, please provide workpapers for each budget adjustment in Column (2).

Response:

The budget adjustments in column 2 of Exhibit 104, Schedule 1 page 3 are mathematical in nature and represent the difference between the budgeted 12 months ended November 30, 2021 and the normalized historic test year for the twelve months ended November 30, 2020.

Attachment A provides explanations for the fluctuations in the budget.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates
FTY = Future Test Year TME November 30, 2021

Line No.	Cost Element Description	Normalized HTY Twelve Months Ended November 30, 2020 (1) $	Witness Paloney Budget Adjustments 1/ (2) $	Budgeted Twelve Months Ended November 30, 2021 (4)=(1)+(2) $	DR Reference OCA	DR Reference I & E	Explanation
		Exh 4, Sch1, Pg 2		Exh 104, Sch1, Pg 5			
1	Labor	38,012,528	828,472	38,841,000	OCA 1-37		See GAS RR-26.
2	Incentive Compensation	1,900,925	462,075	2,363,000	OCA 1-37	I & E RE 17D	NiSource did not achieve expected NOEPS target by Nov 2020. 2021 is planned at target levels for incentive compensation. Also see GASRR 46.
3	Pension	12,701	(12,701)	-	OCA 1-37		Credit to adjust OPEB expense to zero. See Columbia Statement No. 4 , page 10, for further explanation.
4	Pension Deferral Amortization	844,977	23	845,000	OCA 1-37		Budget fluctuation immaterial.
5	OPEB	-	(1,358,000)	(1,358,000)	OCA 1-37		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
6	Other Employee Benefits	6,712,213	1,368,787	8,081,000	OCA 1-37	I & E RE 19	Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
7	Outside Services	18,736,977	8,937,023	27,674,000	OCA 1-36, 1-37	I & E RE 23 D & 24D	See OCA 1-36 and I & E 24 D.
8	Building Leases	2,501,440	(163,440)	2,338,000	OCA 1-37	I&E-RE-37-D	Building Leases and Other Rents and leases budgeted for 2021 at comparable level to 2020 budgets. 2021 Budgeted Rents and Leases - 2,656 , 2020 Budgeted Rents and Leases 2,857 Variance - (201). See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
9	Other Rent and Leases	473,846	(155,846)	318,000	OCA 1-37	I&E-RE-38-D	
10	Corporate Insurance	7,186,459	522,541	7,709,000	OCA 1-37		The 2021 budget increased from $5,861 in 2020 to $7,709 in 2021. The increases were due to inceases is allocations to CPA due to the sale of Columbia Gas of Massacusetts, as well as increases in premiums for casualty, directors and officers, and cyber categories. See "Corporate Insurance" tab herein for changes in costs and allocations.
11	Injuries and Damages	358,171	(50,171)	308,000	OCA 1-37	I & E 29 D	For book purposes, Injuries and Damages is based upon an accrual and not actual payments, and the budget also relfects a projected accrual amount. . For ratemaking purposes, the HTY accrued is adjusted to a five-year average of Injuries and Damages payments, as adjusted by a GDP Deflator. The pro forma FTY expense is specifically adjusted from the HTY expense by the application of an annual average inflation index. Please see Exhibit 4, Schedule 1, Pg 2 line 11 for the detailed calculations of the rate adjustments.
12	Employee Expenses	1,146,308	511,692	1,658,000	OCA 1-37	I&E-RE-40-D	See GAS RR 46 for an explanation regarding lower than normal employee expenses in 2020. The 2021 budget of $1,658 is comparable to the 2020 budget of $1,642. See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
13	Company Memberships	599,737	(29,737)	570,000	OCA 1-37	I & E 32 D, I & E 33-D	The 2021 Budget of $570 is comparable to the 2020 Budget of $560. See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
14	Utilities and Fuel Used in Company Operations	2,207,819	245,181	2,453,000	OCA 1-37	I&E-RE-49-D	The budget adjustment adjusts the normalized HY to the budgeted level in the FTY, and includes gas used in company operations. Gas used in company operations is removed via a ratemaking adjustment. See Columbia statement No. 4 for further information.
15	Advertising	524,096	283,904	808,000	OCA 1-37		See GAS RR 46 for an explanation regarding transition of costs from Outside Services and Corporate Service to Advertising expenses. The budget of $808k is in line with actual spend from 2020 as identified in GAS RR 46.
16	Fleet & Other Clearing	6,459,757	(11,757)	6,448,000	OCA 1-37		2021 budget is comparable 2020 Budget. 2021 budget is $6,448 , and 2020 budget is $6,671 for a variance of ($223). See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
17	Materials & Supplies	6,575,513	(435,513)	6,140,000	OCA 1-37		See GAS RR 46 for an explanation regarding actual costs for materials and supplies exceeding budget in 2020. The budget of $6,140 k is in line with actual spend from 2020 as identified in GAS RR 46.
18	Other O&M	642,041	1,075,959	1,718,000	OCA 1-37		Budget adjustment includes $1.2M for non-recurring consulting fees for NiSource Next. Please see Exhibit 104, Schedule 2, Page 11 for ratemaking adjustment to remove from the FTY.
19	PUC, OCA, OSBA Fees	2,008,792	253,208	2,262,000	OCA 1-37	I & E 36 D	The budget for the Fees herein were based off budget to actual assessment for the HTY and reflect the most up to date invoice factors in the Assessment Notice received by the company in September 2020. The fees fluctuate year to year, please see the "PUC Assessment Factors" tab, and are reported in the Company's Annual report to the PUC. Based on the average fees from 2015 - 2020, a budget of $2.2 million is reasonable. See Attachment A for amounts incuded in the Company's annual report.
20	NCSC	58,867,018	17,229,982	76,097,000	OCA 1-37	I & E RE 43, 44, 45	See NCSC Tab.
21	NCSC OPEB costs Amortization	90,313	(313)	90,000	OCA 1-37		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)

1/ - Budget adjustmnets herein relfect the difference between the budget and the normalized expenses as of November 30, 2020.
Normlalized expenses for 2020 represent several impacts from COVID.

Exhibit No. 104
Schedule No. 1
Page 4 of 6
Witness: K. K. Miller
Witness: N. M. Paloney

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates

ıre Test Year TME December 31, 2022

Line No.	Cost Element Description	Normalized FTY Twelve Months Ended November 30, 2021 (1) $	Witness Paloney: Budget Adjustments (2) $	Budgeted Twelve Months Ended December 31, 2022 (4)=(1)+(2) $	DR Reference: OCA	DR Reference: I & E	Explanation
		Exh 104, Sch1, Pg 3		Exh 104, Sch1, Pg 6	OCA	I & E	Explanation
1	Labor	39,345,421	(97,421)	39,248,000	OCA 1-38		See GAS RR-26.
2	Incentive Compensation	2,363,000	82,000	2,445,000	OCA 1-38	I & E RE 17D	Budget adjustment the result of inflation.
3	Pension	-	-	-	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
4	Pension Deferral Amortization	844,977	23	845,000	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
5	OPEB	-	(439,000)	(439,000)	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
6	Other Employee Benefits	8,081,000	327,000	8,408,000	OCA 1-38	I & E RE 19	Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
7	Outside Services	27,377,979	1,224,021	28,602,000	OCA 1-38	I & E RE 23 D & 24D	Increase is the result of a $1,000,000 in increases in various field operational programs: Cross bores , Field Assembled Risers (Company and Customer owned), righs of way clearing, and GPS Legacy .
8	Building Leases	2,475,855	(122,855)	2,353,000	OCA 1-38	I&E-RE-37-D	Building Leases and Other Rents and leases budgeted for 2022 at comparable level to 2021.
9	Other Rent and Leases	318,000	8,000	326,000	OCA 1-38	I&E-RE-38-D	
10	Corporate Insurance	7,709,000	456,000	8,165,000	OCA 1-38	I & E 26 D	The changes to policy premiums that occur mid and late year in the Normalized FTY are the main drivers of the increase in the Budgeted Twelve Months Ended 12/31/22, with a mid-year inflationary adjustment of 2.05% applied in July, 2022
11	Injuries and Damages	364,045	(64,045)	300,000	OCA 1-38		For book purposes, Injuries and Damages is based upon an accrual and not actual payments, and the budget also relfects a projected accrual amount. . For ratemaking purposes, the HTY accrued is adjusted to a five-year average of Injuries and Damages payments, as adjusted by a GDP Deflator. The pro forma FTY expense is specifically adjusted from the HTY expense by the application of an annual average inflation index, and the FPFTY follows the same process. Please see Exhibit 104, Schedule 1, Pg 2, Line 11 for the detailed calculations of the rate adjustments.
12	Employee Expenses	1,568,977	53,023	1,622,000	OCA 1-38	I&E-RE-40-D	Employee expenses budgeted for 2022 at comparable level to 2021.
13	Company Memberships	526,456	(3,456)	523,000	OCA 1-38	I & E 32 D	Compnay memberships budgeted for 2022 at comparable level to 2021.
14	Utilities and Fuel Used in Company Operations	2,136,905	393,095	2,530,000	OCA 1-38	I&E-RE-49-D	The budget adjustment adjusts the normalized HY to the budgeted level in the FTY, and includes gas used in company operations. Gas used in company operations is removed via a ratemaking adjustment. See Columbia statement No. 4 for further information.
15	Advertising	525,166	284,834	810,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
16	Fleet & Other Clearing	6,448,000	(14,000)	6,434,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
17	Materials & Supplies	6,135,826	23,174	6,159,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
18	Other O&M	535,400	35,600	571,000	OCA 1-38		Employee expenses budgeted for 2022 at comparable level to 2021, after ratemaking adjustment.
19	PUC, OCA, OSBA Fees	2,262,000	-	2,262,000	OCA 1-38	I&E-RE-36-D	See response in OCA 1-37.
20	NCSC	73,506,538	3,787,462	77,294,000	OCA 1-38	I & E RE 43, 44, 45	See NCSC Tab.
21	NCSC OPEB costs Amortization	90,000	-	90,000	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)

NCSC Expense	With Ratemaking Adjustments	Without Ratemaking Adjustments	
HTY Per Books	60,507,458	60,507,458	
Ratemaking	(1,640,440)		
Normalized HTY	58,867,018	**15,589,542**	See below.
	17,229,982		
FTY Budget	76,097,000	76,097,000	
Ratemaking	(2,590,462)		
Normalized FTY	73,506,538	**1,197,000**	Changes primarily the result of decrease of $250k in Picarro costs in the FTY, offsent by in increase of $650k to the safety plan in the FPFTY.
	3,787,462		
FPFTY Budget	77,294,000	77,294,000	
Ratemaking	(433,995)		
Normalized FPFTY	76,860,005		
	Need to Explain ^		

HTY to FTY

Primary Drivers for Increase	**Increases**	
Sale of CMA	11.4	
Severance of Employees	1.9	Please see Exhibit 104, Schedule 2, Page 14, Line 10 for ratemaking adjustment to remove.
Safety Plan	5.1	
NiNext Net Savings	-2.3	See GAS-RR-053
Other	-0.5	
	15.6	

1. Sale of CMA - in 2020, NiSource sold Columbia Gas of Massachusetts. As a result of this sale, there was one less company in which to allocate NCSC costs. See below for the calulcation of the additional costs allocated to Pa as a result of the sale of Columbia Gas of Massachusetts. 2019 represents the last full year expenses were incurred by Columbia Gas of Massachusetts.

Operating Company	2019 Mgmt Allocation	2021 Mgmt Allocation	Change as a result of Sale	2019 Actuals NCSC Costs	2021 Budget NCSC Costs	$$ Impact From 2019 Act.
Columbia Gas of Pennsylvania	13.94%	16.41%	2.47%	461.1	483.9	11.4

2. Employee Severance - As a result of the NiSo next initiative described in GAS RR 53, several NCSC employees were offered and accpeted a Voluntary Severance Package. The portion of the costs allocated to Columbia Gas Of Pennsylvania was $1.9 million. Note, the severance for the NCSC employees is separate from severance recognized in the 2021 and 2022 budget for labor costs for Columbia Gas of Pennsylvania. While this one time cost has been reflect in the Corporate Services expense in 2021, it was removed from the FTY by Company Witness Miller at Exhibit 104, Schedule 2, Pg 14, Line 10.

3. The increase in safety plan expenses relate to the expansion of Columbia's Safety Management (SMS) system as described by Company Witness Kempic in Columbia Statement No. 1. The costs included here represent CPA's portion of this initiative for the following programs.

SMS Expenses

Category	Amount	Description
Staffing	$ 3,028,586	As part of this expansion, additional headcount of approximately 60 individuals will be added to provide enhanced ongoing safety training, quality assurance and quality control training and operator qualification training. These positions are in the process of being posted, and it is the Company's intention to fill them as quickly as possible.
Picarro Leak Detection	$ 611,132	As discussed in Company Witness Anstead's testimony at Columbia Statement No. 14, Columbia intends to employ the Picarro platform system in 2021 to enhance its process for leak detection and to refine the prioritization of repairs and replacements for its natural gas distribution system. In addition to the units discussed at Columbia Statement No. 14, one Picarro unit is being procured at the NiSource level to focus on risk reduction and reduction of methane levels by surveying approximately 2000 miles of pipe in PA.

Isometric Drawing for Measurement and Regualtion Station	$ 654,785	The company will create isometric drawings for 241 existing M&R Stations in PA with inlet pressures greater than 125psi and outlet pressures less than 99psi. These stations represent the second highest risk to customers, in the event of an Overpressure, with loow pressure stations being the highest risk. The company is current in the process of addressing low pressure concerns.
PHMSA Compliance Requirements: Traceablke, Verifiable and Complete (TVC) Record Validation	$ 829,394	In order to comply with the Pipeline and Hazardous Materials Safety Administration (PHMSA) Mega Rule regarding traceable, verifiable and complete (TVC) records, the company is utilizing an engineering contractor to mine pipeline data on 16 Transmission pipeline subsystems and 11 Measurement and Regulations stations in PA. There are only 16 transmission pipeline subsystems in PA. This will complete the required work for all of those assets, to determine if they need to have their MAOP revalidated.
	$ 5,123,897	

CPA								
	2020			2021			Variance	
Category	Allocation	Total Premium	CPA Share	Allocation	Total Premium	CPA Share	Allocation Change	Premium Increase
Casualty								
Excess Casualty	11.30%	14,118,716	1,595,415	15.50%	13,358,598	2,070,583	4%	$ 475,167.71
AEGIS	11.30%	12,424,470	1,403,965	15.50%	12,461,491	1,931,531	4%	$ 527,566.03
Affiliated Casualty	11.30%	11,342,337	1,281,684	15.50%	11,769,387	1,824,255	4%	$ 542,570.91
Casualty Fees	11.30%	2,072,536	234,197	15.50%	1,897,430	294,102	4%	$ 59,905.07
Professional	11.30%	144,544	16,333	15.50%	146,813	22,756	4%	$ 6,422.47
Executive Risk								
D&O	11.71%	3,162,162	370,289	13.68%	3,371,577	461,232	2%	$ 90,942.51
Fiduciary	11.71%	546,750	64,024	13.68%	552,571	75,592	2%	$ 11,567.28
Crime	11.71%	128,618	15,061	13.68%	127,436	17,433	2%	$ 2,372.05
Special Crime	11.71%	3,922	459	13.68%	3,541	484	2%	$ 25.15
Executive Risk Fees	11.71%	203,356	23,813	13.68%	203,683	27,864	2%	$ 4,050.86
Cyber								
Cyber	8.37%	1,148,942	96,166	10.12%	1,136,123	114,976	2%	$ 18,809.24
Property								
Property	1.72%	5,401,076	92,953	2.60%	5,141,855	133,637	1%	$ 40,684.28
Property Retained Losses	1.91%	911,465	17,427	2.89%	793,232	22,909	1%	$ 5,481.34
Property Fees	1.72%	831,839	14,316	2.60%	693,581	18,026	1%	$ 3,710.23
Medical Stop Loss								
Medical Stop Loss	5.40%	3,168,445	171,096	5.64%	3,171,000	178,741	0%	$ 7,645.10
Workers Comp								
Workers' Comp	8.10%	675,559	54,720	11.50%	611,607	70,335	3%	$ 15,614.49
Affiliated Work Comp	8.10%	3,238,152	262,290	11.50%	2,856,522	328,500	3%	$ 66,209.68
Workers' Comp Fees	8.10%	223,487	18,102	11.50%	211,042	24,270	3%	$ 6,167.36
ESIS WC	8.10%	150,601	12,199	11.50%	143,884	16,547	3%	$ 4,347.93
ESIS Casualty	11.30%	1,403,123	158,553	15.50%	1,205,863	186,909	4%	$ 28,355.91
ESIS Short Term Disability	11.45%	290,817	33,304	14.21%	273,514	38,875	3%	$ 5,570.91
					Projected Increase In Expense			**$ 1,923,186.51**

PUC/OCA/OSBA Fees		
Year	**Amount**	**% Change**
2015	$2,160,919	
2016	$2,170,560	0.446%
2017	$2,037,807	-6.116%
2018	$2,623,298	28.731%
2019	$2,063,274	-21.348%
2020	$2,008,792	-2.641%
Average	$2,177,442	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1														
2														
3														
4														
5														
6								Budget						
7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor		23,873	23,108	22,910	23,693	25,709	25,251	28,309	29,646	31,181	31,534	32,271	36,572
9	Incentive Compensation		293	1,171	1,149	1,249	1,238	1,333	1,584	1,642	1,742	2,150	1,133	2,676
10	Pension		2,119	6,005	6,598	-	3	1,137	-	6	549	-	-	
11	OPEB		715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)	(678)
12	Other Employee Benefits		5,076	6,363	6,509	6,184	6,454	4,584	4,791	5,635	5,975	6,445	6,851	7,302
13	Outside Services		15,636	15,175	13,094	12,123	12,104	22,311	26,079	23,977	25,458	22,634	23,453	22,167
14	Rent and Leases		1,314	1,374	1,458	1,615	1,887	2,273	4,791	3,607	3,873	3,203	3,296	2,857
15	Corporate Insurance		3,116	3,574	3,413	3,048	3,004	3,087	4,516	3,481	3,705	3,495	3,631	5,861
16	Injuries and Damages		1,209	944	795	630	630	500	500	400	-	400	400	400
17	Employee Expenses		1,109	1,046	1,163	1,142	1,295	1,305	1,640	1,452	1,501	1,584	1,483	1,642
18	Company Memberships		347	345	249	292	262	256	256	332	491	491	563	560
19	Utilities and Fuel Used in Company Operations		675	570	567	503	1,167	1,303	1,310	1,370	1,102	1,709	1,715	2,142
20	Advertising		500	185	170	170	470	170	170	170	170	170	174	174
21	Fleet		4,663	4,104	4,421	5,046	5,452	5,708	5,728	5,797	5,879	6,255	5,673	6,671
22	Materials & Supplies		4,929	4,767	4,775	4,899	4,649	5,024	5,067	5,962	5,366	5,865	5,568	5,755
23	Other O&M		(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381	193
24	PUC, OCA, OSBA Fees		1,673	1,953	1,354	1,454	1,699	1,583	2,161	2,330	2,460	2,262	2,341	2,262
25	NCSC Shared Services & NGD Shared Operations		31,889	38,399	37,740	39,742	44,597	47,962	49,533	57,719	67,158	66,049	64,185	59,051
26	Amortization		82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		95,231	106,443	106,498	99,407	108,941	121,516	134,890	143,604	157,656	154,193	154,233	156,541
29														
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	A	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
6			Actuals											
7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor		23,153	23,577	22,845	23,996	25,124	25,818	27,980	29,093	30,019	32,461	36,471	36,293
9	Incentive Compensation		1,303	1,628	1,649	1,690	1,845	1,816	1,791	1,981	2,590	1,381	1,246	2,137
10	Pension		392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12	13
11	OPEB		1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)	(693)
12	Other Employee Benefits		4,995	7,472	6,210	5,880	5,635	5,432	5,992	5,924	6,099	6,015	6,931	9,181
13	Outside Services		15,180	15,440	13,244	12,133	14,113	22,070	22,951	25,361	28,246	21,352	22,850	15,615
14	Rent and Leases		1,306	1,207	1,348	1,485	1,699	1,699	2,252	2,831	3,453	3,234	3,409	2,592
15	Corporate Insurance		3,045	3,241	2,926	2,763	2,734	2,796	2,899	3,024	3,176	3,239	4,363	6,281
16	Injuries and Damages		605	545	340	241	305	(185)	381	363	337	270	512	317
17	Employee Expenses		1,405	1,450	1,553	1,465	1,376	1,264	1,415	1,381	1,545	1,383	1,713	1,063
18	Company Memberships		295	250	293	262	249	313	479	563	599	527	569	854
19	Utilities and Fuel Used in Company Operations		451	417	487	1,094	1,247	1,244	1,287	1,460	1,679	1,693	1,723	1,871
20	Advertising		389	281	167	133	243	236	207	226	283	146	224	719
21	Fleet		4,650	4,726	5,092	5,357	5,780	6,106	5,956	6,206	6,320	6,338	6,906	6,389
22	Materials & Supplies		4,741	4,967	4,412	4,353	5,171	5,343	5,873	5,461	6,327	5,627	6,320	6,643
23	Other O&M		(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242	982
24	PUC, OCA, OSBA Fees		1,721	1,539	1,348	1,523	1,585	1,815	2,161	1,960	1,846	1,814	2,113	2,125
25	NCSC Shared Services & NGD Shared Operations		34,023	36,457	38,899	40,164	43,374	50,760	53,169	56,264	68,727	63,166	64,147	62,366
26	Amortization		82	0	(489)	(1,446)	(594)	185	267	396	511	845	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		95,892	106,766	113,356	101,209	111,952	127,057	134,044	142,299	170,532	141,304	161,271	155,683

	A	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN
6								Variance						
7	CE		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8	Labor		(720)	469	(65)	303	(585)	567	(329)	(553)	(1,162)	927	4,200	(279)
9	Incentive Compensation		1,010	457	500	441	607	484	207	339	848	(769)	113	(539)
10	Pension		(1,727)	(206)	6,490	91	2,486	(6)	14	15	7,989	(8,417)	12	13
11	OPEB		968	(290)	(705)	242	(170)	(748)	42	227	104	266	405	(15)
12	Other Employee Benefits		(81)	1,109	(299)	(304)	(819)	848	1,201	289	124	(429)	80	1,879
13	Outside Services		(456)	265	150	10	2,009	(241)	(3,128)	1,384	2,788	(1,282)	(603)	(6,552)
14	Rent and Leases		(8)	(167)	(110)	(130)	(188)	(574)	(2,539)	(776)	(420)	31	113	(266)
15	Corporate Insurance		(71)	(333)	(487)	(285)	(270)	(291)	(1,617)	(457)	(529)	(255)	732	420
16	Injuries and Damages		(604)	(399)	(455)	(389)	(325)	(685)	(119)	(37)	337	(130)	112	(83)
17	Employee Expenses		296	404	390	323	81	(41)	(225)	(71)	44	(202)	230	(578)
18	Company Memberships		(52)	(95)	44	(30)	(13)	57	223	231	108	35	6	294
19	Utilities and Fuel Used in Company Operations		(224)	(153)	(80)	591	80	(59)	(23)	90	577	(16)	8	(272)
20	Advertising		(111)	96	(3)	(37)	(227)	66	37	56	113	(24)	51	546
21	Fleet		(13)	622	671	311	328	398	228	409	441	83	1,233	(283)
22	Materials & Supplies		(188)	200	(363)	(546)	522	319	806	(501)	961	(238)	752	889
23	Other O&M		460	774	272	720	(29)	2,418	740	(26)	(403)	428	(139)	788
24	PUC, OCA, OSBA Fees		48	(413)	(5)	69	(114)	232	-	(370)	(614)	(448)	(228)	(137)
25	NCSC Shared Services & NGD Shared Operations		2,134	(1,942)	1,159	422	(1,223)	2,798	3,636	(1,455)	1,569	(2,884)	(38)	3,315
26	Amortization		(0)	(74)	(246)	(0)	861	-	-	(100)	-	436	-	0
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		661	324	6,858	1,802	3,011	5,542	(846)	(1,305)	12,876	(12,889)	7,038	(858)

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-038:

Referring to Exhibit No. 104, Schedule 1, Page 4, please provide workpapers for each budget adjustment in Column (2).

Response:

The budget adjustments in column 2 of Exhibit 104, Schedule 1 page 4 are mathematical in nature and represent the difference between the budgeted 12 months ended November 30, 2022 and the normalized future test year for the twelve months ended November 30, 2021. See tab “1-38” in OCA 1-37 Attachment A for explanation of budget changes.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates
FTY = Future Test Year TME November 30, 2021

Line No.	Cost Element Description	Normalized HTY Twelve Months Ended November 30, 2020 (1) $	Witness Paloney Budget Adjustments 1/ (2) $	Budgeted Twelve Months Ended November 30, 2021 (4)=(1)+(2) $	DR Reference OCA	DR Reference I & E	Explanation
		Exh 4, Sch1, Pg 2		Exh 104, Sch1, Pg 5	OCA	I & E	Explanation
1	Labor	38,012,528	828,472	38,841,000	OCA 1-37		See GAS RR-26.
2	Incentive Compensation	1,900,925	462,075	2,363,000	OCA 1-37	I & E RE 17D	NiSource did not achieve expected NOEPS target by Nov 2020. 2021 is planned at target levels for incentive compensation. Also see GASRR 46.
3	Pension	12,701	(12,701)	-	OCA 1-37		Credit to adjust OPEB expense to zero. See Columbia Statement No. 4 , page 10, for further explanation.
4	Pension Deferral Amortization	844,977	23	845,000	OCA 1-37		Budget fluctuation immaterial.
5	OPEB	-	(1,358,000)	(1,358,000)	OCA 1-37		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
6	Other Employee Benefits	6,712,213	1,368,787	8,081,000	OCA 1-37	I & E RE 19	Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
7	Outside Services	18,736,977	8,937,023	27,674,000	OCA 1-36, 1-37	I & E RE 23 D & 24D	See OCA 1-36 and I & E 24 D.
8	Building Leases	2,501,440	(163,440)	2,338,000	OCA 1-37	I&E-RE-37-D	Building Leases and Other Rents and leases budgeted for 2021 at comparable level to 2020 budgets. 2021 Budgeted Rents and Leases - 2,656 , 2020 Budgeted Rents and Leases 2,857 Variance - (201). See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
9	Other Rent and Leases	473,846	(155,846)	318,000	OCA 1-37	I&E-RE-38-D	
10	Corporate Insurance	7,186,459	522,541	7,709,000	OCA 1-37		The 2021 budget increased from $5,861 in 2020 to $7,709 in 2021. The increases were due to inceases is allocations to CPA due to the sale of Columbia Gas of Massacusetts, as well as increases in premiums for casualty, directors and officers, and cyber categories. See "Corporate Insurance" tab herein for changes in costs and allocations.
11	Injuries and Damages	358,171	(50,171)	308,000	OCA 1-37	I & E 29 D	For book purposes, Injuries and Damages is based upon an accrual and not actual payments, and the budget also relfects a projected accrual amount. . For ratemaking purposes, the HTY accrued is adjusted to a five-year average of Injuries and Damages payments, as adjusted by a GDP Deflator. The pro forma FTY expense is specifically adjusted from the HTY expense by the application of an annual average inflation index. Please see Exhibit 4, Schedule 1, Pg 2 line 11 for the detailed calculations of the rate adjustments.
12	Employee Expenses	1,146,308	511,692	1,658,000	OCA 1-37	I&E-RE-40-D	See GAS RR 46 for an explanation regarding lower than normal employee expenses in 2020. The 2021 budget of $1,658 is comparable to the 2020 budget of $1,642. See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
13	Company Memberships	599,737	(29,737)	570,000	OCA 1-37	I & E 32 D, I & E 33-D	The 2021 Budget of $570 is comparable to the 2020 Budget of $560. See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
14	Utilities and Fuel Used in Company Operations	2,207,819	245,181	2,453,000	OCA 1-37	I&E-RE-49-D	The budget adjustment adjusts the normalized HY to the budgeted level in the FTY, and includes gas used in company operations. Gas used in company operations is removed via a ratemaking adjustment. See Columbia statement No. 4 for further information.
15	Advertising	524,096	283,904	808,000	OCA 1-37		See GAS RR 46 for an explanation regarding transition of costs from Outside Services and Corporate Service to Advertising expenses. The budget of $808k is in line with actual spend from 2020 as identified in GAS RR 46.
16	Fleet & Other Clearing	6,459,757	(11,757)	6,448,000	OCA 1-37		2021 budget is comparable 2020 Budget. 2021 budget is $6,448 , and 2020 budget is $6,671 for a variance of ($223). See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
17	Materials & Supplies	6,575,513	(435,513)	6,140,000	OCA 1-37		See GAS RR 46 for an explanation regarding actual costs for materials and supplies exceeding budget in 2020. The budget of $6,140 k is in line with actual spend from 2020 as identified in GAS RR 46.
18	Other O&M	642,041	1,075,959	1,718,000	OCA 1-37		Budget adjustment includes $1.2M for non-recurring consulting fees for NiSource Next. Please see Exhibit 104, Schedule 2, Page 11 for ratemaking adjustment to remove from the FTY.
19	PUC, OCA, OSBA Fees	2,008,792	253,208	2,262,000	OCA 1-37	I & E 36 D	The budget for the Fees herein were based off budget to actual assessment for the HTY and reflect the most up to date invoice factors in the Assessment Notice received by the company in September 2020. The fees fluctuate year to year, please see the "PUC Assessment Factors" tab, and are reported in the Company's Annual report to the PUC. Based on the average fees from 2015 - 2020, a budget of $2.2 million is reasonable. See Attachment A for amounts incuded in the Company's annual report.
20	NCSC	58,867,018	17,229,982	76,097,000	OCA 1-37	I & E RE 43, 44, 45	See NCSC Tab.
21	NCSC OPEB costs Amortization	90,313	(313)	90,000	OCA 1-37		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)

1/ - Budget adjustmnets herein relfect the difference between the budget and the normalized expenses as of November 30, 2020.
Normlalized expenses for 2020 represent several impacts from COVID.

Exhibit No. 104
Schedule No. 1
Page 4 of 6
Witness: K. K. Miller
Witness: N. M. Paloney
Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates

ıre Test Year TME December 31, 2022

Line No.	Cost Element Description	Normalized FTY Twelve Months Ended November 30, 2021 (1) $	Witness Paloney Budget Adjustments (2) $	Budgeted Twelve Months Ended December 31, 2022 (4)=(1)+(2) $	DR Reference OCA	DR Reference I & E	Explanation
		Exh 104, Sch1, Pg 3		Exh 104, Sch1, Pg 6	OCA	I & E	Explanation
1	Labor	39,345,421	(97,421)	39,248,000	OCA 1-38		See GAS RR-26.
2	Incentive Compensation	2,363,000	82,000	2,445,000	OCA 1-38	I & E RE 17D	Budget adjustment the result of inflation.
3	Pension	-	-	-	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
4	Pension Deferral Amortization	844,977	23	845,000	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
5	OPEB	-	(439,000)	(439,000)	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
6	Other Employee Benefits	8,081,000	327,000	8,408,000	OCA 1-38	I & E RE 19	Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
7	Outside Services	27,377,979	1,224,021	28,602,000	OCA 1-38	I & E RE 23 D & 24D	Increase is the result of a $1,000,000 in increases in various field operational programs: Cross bores , Field Assembled Risers (Company and Customer owned), righs of way clearing, and GPS Legacy .
8	Building Leases	2,475,855	(122,855)	2,353,000	OCA 1-38	I&E-RE-37-D	Building Leases and Other Rents and leases budgeted for 2022 at comparable level to 2021.
9	Other Rent and Leases	318,000	8,000	326,000	OCA 1-38	I&E-RE-38-D	
10	Corporate Insurance	7,709,000	456,000	8,165,000	OCA 1-38	I & E 26 D	The changes to policy premiums that occur mid and late year in the Normalized FTY are the main drivers of the increase in the Budgeted Twelve Months Ended 12/31/22, with a mid-year inflationary adjustment of 2.05% applied in July, 2022
11	Injuries and Damages	364,045	(64,045)	300,000	OCA 1-38		For book purposes, Injuries and Damages is based upon an accrual and not actual payments, and the budget also relfects a projected accrual amount. . For ratemaking purposes, the HTY accrued is adjusted to a five-year average of Injuries and Damages payments, as adjusted by a GDP Deflator. The pro forma FTY expense is specifically adjusted from the HTY expense by the application of an annual average inflation index, and the FPFTY follows the same process. Please see Exhibit 104, Schedule 1, Pg 2, Line 11 for the detailed calculations of the rate adjustments.
12	Employee Expenses	1,568,977	53,023	1,622,000	OCA 1-38	I&E-RE-40-D	Employee expenses budgeted for 2022 at comparable level to 2021.
13	Company Memberships	526,456	(3,456)	523,000	OCA 1-38	I & E 32 D	Compnay memberships budgeted for 2022 at comparable level to 2021.
14	Utilities and Fuel Used in Company Operations	2,136,905	393,095	2,530,000	OCA 1-38	I&E-RE-49-D	The budget adjustment adjusts the normalized HY to the budgeted level in the FTY, and includes gas used in company operations. Gas used in company operations is removed via a ratemaking adjustment. See Columbia statement No. 4 for further information.
15	Advertising	525,166	284,834	810,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
16	Fleet & Other Clearing	6,448,000	(14,000)	6,434,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
17	Materials & Supplies	6,135,826	23,174	6,159,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
18	Other O&M	535,400	35,600	571,000	OCA 1-38		Employee expenses budgeted for 2022 at comparable level to 2021, after ratemaking adjustment.
19	PUC, OCA, OSBA Fees	2,262,000	-	2,262,000	OCA 1-38	I&E-RE-36-D	See response in OCA 1-37.
20	NCSC	73,506,538	3,787,462	77,294,000	OCA 1-38	I & E RE 43, 44, 45	See NCSC Tab.
21	NCSC OPEB costs Amortization	90,000	-	90,000	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)

NCSC Expense	With Ratemaking Adjustments	Without Ratemaking Adjustments	
HTY Per Books	60,507,458	60,507,458	
Ratemaking	(1,640,440)		
Normalized HTY	58,867,018	**15,589,542**	See below.
	17,229,982		
FTY Budget	76,097,000	76,097,000	
Ratemaking	(2,590,462)		
Normalized FTY	73,506,538	**1,197,000**	Changes primarily the result of decrease of $250k in Picarro costs in the FTY, offsent by in increase of $650k to the safety plan in the FPFTY.
	3,787,462		
FPFTY Budget	77,294,000	77,294,000	
Ratemaking	(433,995)		
Normalized FPFTY	76,860,005		
	Need to Explain ^		

HTY to FTY

Primary Drivers for Increase	Increases	
Sale of CMA	11.4	
Severance of Employees	1.9	Please see Exhibit 104, Schedule 2, Page 14, Line 10 for ratemaking adjustment to remove.
Safety Plan	5.1	
NiNext Net Savings	-2.3	See GAS-RR-053
Other	-0.5	
	15.6	

1. Sale of CMA - in 2020, NiSource sold Columbia Gas of Massachusetts. As a result of this sale, there was one less company in which to allocate NCSC costs. See below for the calulcation of the additional costs allocated to Pa as a result of the sale of Columbia Gas of Massachusetts. 2019 represents the last full year expenses were incurred by Columbia Gas of Massachusetts.

Operating Company	2019 Mgmt Allocation	2021 Mgmt Allocation	Change as a result of Sale	2019 Actuals NCSC Costs	2021 Budget NCSC Costs	$$ Impact From 2019 Act.
Columbia Gas of Pennsylvania	13.94%	16.41%	2.47%	461.1	483.9	11.4

2. Employee Severance - As a result of the NiSo next initiative described in GAS RR 53, several NCSC employees were offered and accpeted a Voluntary Severance Package. The portion of the costs allocated to Columbia Gas Of Pennsylvania was $1.9 million. Note, the severance for the NCSC employees is separate from severance recognized in the 2021 and 2022 budget for labor costs for Columbia Gas of Pennsylvania. While this one time cost has been reflect in the Corporate Services expense in 2021, it was removed from the FTY by Company Witness Miller at Exhibit 104, Schedule 2, Pg 14, Line 10.

3. The increase in safety plan expenses relate to the expansion of Columbia's Safety Management (SMS) system as described by Company Witness Kempic in Columbia Statement No. 1. The costs included here represent CPA's portion of this initiative for the following programs.

SMS Expenses

Category	Amount	Description
Staffing	$ 3,028,586	As part of this expansion, additional headcount of approximately 60 individuals will be added to provide enhanced ongoing safety training, quality assurance and quality control training and operator qualification training. These positions are in the process of being posted, and it is the Company's intention to fill them as quickly as possible.
Picarro Leak Detection	$ 611,132	As discussed in Company Witness Anstead's testimony at Columbia Statement No. 14, Columbia intends to employ the Picarro platform system in 2021 to enhance its process for leak detection and to refine the prioritization of repairs and replacements for its natural gas distribution system. In addition to the units discussed at Columbia Statement No. 14, one Picarro unit is being procured at the NiSource level to focus on risk reduction and reduction of methane levels by surveying approximately 2000 miles of pipe in PA.

Isometric Drawing for Measurement and Regualtion Station	$ 654,785	The company will create isometric drawings for 241 existing M&R Stations in PA with inlet pressures greater than 125psi and outlet pressures less than 99psi. These stations represent the second highest risk to customers, in the event of an Overpressure, with loow pressure stations being the highest risk. The company is current in the process of addressing low pressure concerns.
PHMSA Compliance Requirements: Traceablke, Verifiable and Complete (TVC) Record Validation	$ 829,394	In order to comply with the Pipeline and Hazardous Materials Safety Administration (PHMSA) Mega Rule regarding traceable, verifiable and complete (TVC) records, the company is utilizing an engineering contractor to mine pipeline data on 16 Transmission pipeline subsystems and 11 Measurement and Regulations stations in PA. There are only 16 transmission pipeline subsystems in PA. This will complete the required work for all of those assets, to determine if they need to have their MAOP revalidated.
	$ 5,123,897	

CPA								
Category	2020			2021			Variance	
	Allocation	Total Premium	CPA Share	Allocation	Total Premium	CPA Share	Allocation Change	Premium Increase
Casualty								
Excess Casualty	11.30%	14,118,716	1,595,415	15.50%	13,358,598	2,070,583	4%	$ 475,167.71
AEGIS	11.30%	12,424,470	1,403,965	15.50%	12,461,491	1,931,531	4%	$ 527,566.03
Affiliated Casualty	11.30%	11,342,337	1,281,684	15.50%	11,769,387	1,824,255	4%	$ 542,570.91
Casualty Fees	11.30%	2,072,536	234,197	15.50%	1,897,430	294,102	4%	$ 59,905.07
Professional	11.30%	144,544	16,333	15.50%	146,813	22,756	4%	$ 6,422.47
Executive Risk								
D&O	11.71%	3,162,162	370,289	13.68%	3,371,577	461,232	2%	$ 90,942.51
Fiduciary	11.71%	546,750	64,024	13.68%	552,571	75,592	2%	$ 11,567.28
Crime	11.71%	128,618	15,061	13.68%	127,436	17,433	2%	$ 2,372.05
Special Crime	11.71%	3,922	459	13.68%	3,541	484	2%	$ 25.15
Executive Risk Fees	11.71%	203,356	23,813	13.68%	203,683	27,864	2%	$ 4,050.86
Cyber								
Cyber	8.37%	1,148,942	96,166	10.12%	1,136,123	114,976	2%	$ 18,809.24
Property								
Property	1.72%	5,401,076	92,953	2.60%	5,141,855	133,637	1%	$ 40,684.28
Property Retained Losses	1.91%	911,465	17,427	2.89%	793,232	22,909	1%	$ 5,481.34
Property Fees	1.72%	831,839	14,316	2.60%	693,581	18,026	1%	$ 3,710.23
Medical Stop Loss								
Medical Stop Loss	5.40%	3,168,445	171,096	5.64%	3,171,000	178,741	0%	$ 7,645.10
Workers Comp								
Workers' Comp	8.10%	675,559	54,720	11.50%	611,607	70,335	3%	$ 15,614.49
Affiliated Work Comp	8.10%	3,238,152	262,290	11.50%	2,856,522	328,500	3%	$ 66,209.68
Workers' Comp Fees	8.10%	223,487	18,102	11.50%	211,042	24,270	3%	$ 6,167.36
ESIS WC	8.10%	150,601	12,199	11.50%	143,884	16,547	3%	$ 4,347.93
ESIS Casualty	11.30%	1,403,123	158,553	15.50%	1,205,863	186,909	4%	$ 28,355.91
ESIS Short Term Disability	11.45%	290,817	33,304	14.21%	273,514	38,875	3%	$ 5,570.91
					Projected Increase In Expense			**$ 1,923,186.51**

PUC/OCA/OSBA Fees		
Year	**Amount**	**% Change**
2015	$2,160,919	
2016	$2,170,560	0.446%
2017	$2,037,807	-6.116%
2018	$2,623,298	28.731%
2019	$2,063,274	-21.348%
2020	$2,008,792	-2.641%
Average	$2,177,442	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1														
2														
3														
4														
5														
6									Budget					
7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor		23,873	23,108	22,910	23,693	25,709	25,251	28,309	29,646	31,181	31,534	32,271	36,572
9	Incentive Compensation		293	1,171	1,149	1,249	1,238	1,333	1,584	1,642	1,742	2,150	1,133	2,676
10	Pension		2,119	6,005	6,598	-	3	1,137	-	6	549	-	-	
11	OPEB		715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)	(678)
12	Other Employee Benefits		5,076	6,363	6,509	6,184	6,454	4,584	4,791	5,635	5,975	6,445	6,851	7,302
13	Outside Services		15,636	15,175	13,094	12,123	12,104	22,311	26,079	23,977	25,458	22,634	23,453	22,167
14	Rent and Leases		1,314	1,374	1,458	1,615	1,887	2,273	4,791	3,607	3,873	3,203	3,296	2,857
15	Corporate Insurance		3,116	3,574	3,413	3,048	3,004	3,087	4,516	3,481	3,705	3,495	3,631	5,861
16	Injuries and Damages		1,209	944	795	630	630	500	500	400	-	400	400	400
17	Employee Expenses		1,109	1,046	1,163	1,142	1,295	1,305	1,640	1,452	1,501	1,584	1,483	1,642
18	Company Memberships		347	345	249	292	262	256	256	332	491	491	563	560
19	Utilities and Fuel Used in Company Operations		675	570	567	503	1,167	1,303	1,310	1,370	1,102	1,709	1,715	2,142
20	Advertising		500	185	170	170	470	170	170	170	170	170	174	174
21	Fleet		4,663	4,104	4,421	5,046	5,452	5,708	5,728	5,797	5,879	6,255	5,673	6,671
22	Materials & Supplies		4,929	4,767	4,775	4,899	4,649	5,024	5,067	5,962	5,366	5,865	5,568	5,755
23	Other O&M		(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381	193
24	PUC, OCA, OSBA Fees		1,673	1,953	1,354	1,454	1,699	1,583	2,161	2,330	2,460	2,262	2,341	2,262
25	NCSC Shared Services & NGD Shared Operations		31,889	38,399	37,740	39,742	44,597	47,962	49,533	57,719	67,158	66,049	64,185	59,051
26	Amortization		82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		95,231	106,443	106,498	99,407	108,941	121,516	134,890	143,604	157,656	154,193	154,233	156,541
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	A	P	Q	R	S	T	U	V	W	X	Y	Z	AA
6		Actuals											
7	**CE**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor	23,153	23,577	22,845	23,996	25,124	25,818	27,980	29,093	30,019	32,461	36,471	36,293
9	Incentive Compensation	1,303	1,628	1,649	1,690	1,845	1,816	1,791	1,981	2,590	1,381	1,246	2,137
10	Pension	392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12	13
11	OPEB	1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)	(693)
12	Other Employee Benefits	4,995	7,472	6,210	5,880	5,635	5,432	5,992	5,924	6,099	6,015	6,931	9,181
13	Outside Services	15,180	15,440	13,244	12,133	14,113	22,070	22,951	25,361	28,246	21,352	22,850	15,615
14	Rent and Leases	1,306	1,207	1,348	1,485	1,699	1,699	2,252	2,831	3,453	3,234	3,409	2,592
15	Corporate Insurance	3,045	3,241	2,926	2,763	2,734	2,796	2,899	3,024	3,176	3,239	4,363	6,281
16	Injuries and Damages	605	545	340	241	305	(185)	381	363	337	270	512	317
17	Employee Expenses	1,405	1,450	1,553	1,465	1,376	1,264	1,415	1,381	1,545	1,383	1,713	1,063
18	Company Memberships	295	250	293	262	249	313	479	563	599	527	569	854
19	Utilities and Fuel Used in Company Operations	451	417	487	1,094	1,247	1,244	1,287	1,460	1,679	1,693	1,723	1,871
20	Advertising	389	281	167	133	243	236	207	226	283	146	224	719
21	Fleet	4,650	4,726	5,092	5,357	5,780	6,106	5,956	6,206	6,320	6,338	6,906	6,389
22	Materials & Supplies	4,741	4,967	4,412	4,353	5,171	5,343	5,873	5,461	6,327	5,627	6,320	6,643
23	Other O&M	(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242	982
24	PUC, OCA, OSBA Fees	1,721	1,539	1,348	1,523	1,585	1,815	2,161	1,960	1,846	1,814	2,113	2,125
25	NCSC Shared Services & NGD Shared Operations	34,023	36,457	38,899	40,164	43,374	50,760	53,169	56,264	68,727	63,166	64,147	62,366
26	Amortization	82	0	(489)	(1,446)	(594)	185	267	396	511	845	845	935
27	Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**	95,892	106,766	113,356	101,209	111,952	127,057	134,044	142,299	170,532	141,304	161,271	155,683

	A	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN
1														
2														
3														
4														
5														
6								Variance						
7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor		(720)	469	(65)	303	(585)	567	(329)	(553)	(1,162)	927	4,200	(279)
9	Incentive Compensation		1,010	457	500	441	607	484	207	339	848	(769)	113	(539)
10	Pension		(1,727)	(206)	6,490	91	2,486	(6)	14	15	7,989	(8,417)	12	13
11	OPEB		968	(290)	(705)	242	(170)	(748)	42	227	104	266	405	(15)
12	Other Employee Benefits		(81)	1,109	(299)	(304)	(819)	848	1,201	289	124	(429)	80	1,879
13	Outside Services		(456)	265	150	10	2,009	(241)	(3,128)	1,384	2,788	(1,282)	(603)	(6,552)
14	Rent and Leases		(8)	(167)	(110)	(130)	(188)	(574)	(2,539)	(776)	(420)	31	113	(266)
15	Corporate Insurance		(71)	(333)	(487)	(285)	(270)	(291)	(1,617)	(457)	(529)	(255)	732	420
16	Injuries and Damages		(604)	(399)	(455)	(389)	(325)	(685)	(119)	(37)	337	(130)	112	(83)
17	Employee Expenses		296	404	390	323	81	(41)	(225)	(71)	44	(202)	230	(578)
18	Company Memberships		(52)	(95)	44	(30)	(13)	57	223	231	108	35	6	294
19	Utilities and Fuel Used in Company Operations		(224)	(153)	(80)	591	80	(59)	(23)	90	577	(16)	8	(272)
20	Advertising		(111)	96	(3)	(37)	(227)	66	37	56	113	(24)	51	546
21	Fleet		(13)	622	671	311	328	398	228	409	441	83	1,233	(283)
22	Materials & Supplies		(188)	200	(363)	(546)	522	319	806	(501)	961	(238)	752	889
23	Other O&M		460	774	272	720	(29)	2,418	740	(26)	(403)	428	(139)	788
24	PUC, OCA, OSBA Fees		48	(413)	(5)	69	(114)	232	-	(370)	(614)	(448)	(228)	(137)
25	NCSC Shared Services & NGD Shared Operations		2,134	(1,942)	1,159	422	(1,223)	2,798	3,636	(1,455)	1,569	(2,884)	(38)	3,315
26	Amortization		(0)	(74)	(246)	(0)	861	-	-	(100)	-	436	-	0
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		661	324	6,858	1,802	3,011	5,542	(846)	(1,305)	12,876	(12,889)	7,038	(858)
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Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-070:

Reference Columbia's response to OCA-I-36 concerning outside services. Provide a similar table with additional columns for HTY amounts, FTY budgeted amount, FTY amounts incurred thus far, and the reason for each budgeted increase.

Response:

Please refer to TABLE I&E-RE-70-D below.

TABLE I&E-RE-70-D

Activity	**HTY**		**FTY Budget**	**FTY Actuals through April 2021**
		$Millions		
MAOP	0.1	1.1	1.2	-
Customer Owned Risers *	0.2	1.3	1.5	0.1
Company Owned Risers*	0.7	1.2	1.9	0.6
PACOR	0.1	0.2	0.3	0.1
GPS Legacy	-	0.7	0.7	0.1
Crossbore increase	-	1.4	1.4	-
Field Assembled Riser Increase	-	1.7	1.7	-
ROW	0.7	0.5	1.2	0.7
Other	-	0.5	0.5	-
Total	1.8	8.6	10.4	1.5

* Increase is COVID-19 related.

Increases in the Cross Bore and Field assembled risers budget represent the increase in the 2020 case. While full recovery was not awarded for the risers, the total amount remains in the budget. The fluctuations in the ROW and GPS represents a budget adjustment as a result of the work plan.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 8

Question No. OCA 8-008:

Referring to the response to OCA I-37, Attachment A, Tab OCA I-38, please provide all documentation and workpapers supporting the increase in Outside Services.

Response: The requested information has been provided in OCA 1-37.

Activity	HTY	Increase	Reason for Increase	Further Explanation
MAOP	$0.10	$ 1.10	New Mega Ruling issued	Additional increase due to Mega ruling which affects 25 stations and also needing additional records collections around stations.
Customer Owned Risers	$0.20	$ 1.30	Get back to normal historical run rate	Historical Budget/Spend for Risers is $4M. This was cut during 2020 due to COVID restrictions around entering customers homes to reestablish service.
Company Owned Risers	$0.70	$ 1.20	Get back to normal histiorical run rate	
Field Assembled Risers	$ -	$ 1.70	Accelerate for safety reasons	This was requested in an effort to reduce the total length of the Riser program
PACOR	$0.10	$ 0.20	Get back to normal histiorical run rate	Program funding reallocated in HTY to address leak repairs and abnormal operating considitions.
GPS Legacy	$ -	$ 0.70	Get back to normal histiorical run rate	Program funding reallocated in HTY to address leak repairs and abnormal operating considitions.
Crossbore Increase	$ -	$ 1.40	Accelerate for safety reasons	This was requested in an effort to reduce the total length of the Crossbore program by half.
ROW	$0.70	$ 0.50	Get back to normal histiorical run rate	Program funding reallocated in HTY to address leak repairs and abnormal operating considitions.
Other	$ -	$ 0.50	Misc cost increases	There have been several changes throughout the footprint that require us to increase the OS budget. These changes include but are not limited to contract rate increases, permit cost increases, and new rules around restoration surface sizes that requre larger pave/concrete jobs.
Total	$1.80	$ 8.60		

Theodore J. Gallagher
Assistant General Counsel
Legal Department

NiSource

121 Champion Way, Suite 100
Canonsburg, PA 15317
Office: 724.416.6355
Fax: 724.416.6382
tjgallagher@nisource.com

VIA: ELECTRONIC FILING

April 10, 2019

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, Pennsylvania 17105-3265

Re: Affiliated Interest Agreement – Columbia Gas of Pennsylvania, Inc.
Services Agreement with NiSource Corporate Services Company
Docket No. G-2014-2458547

Dear Ms. Chiavetta:

Enclosed for filing please find a fully executed Service Agreement between Columbia Gas of Pennsylvania, Inc. and Nisource Corporate Services Company (Nisource) pursuant to the Secretarial letter dated April 1, 2019, regarding the above-captioned matter.

Thank you for your kind attention to this matter. Should you have any questions, please do not hesitate to contact the undersigned at 724-416-6355.

Respectfully submitted,

Theodore J. Gallagher

/kak
Enclosure
Cc (Via: Electronic Mail Only)
Debra Backer dbacker@pa.gov
Lee Yalcin - lyalcin@pa.gov
Darren Gill DGILL@pa.gov

Service Agreement

BETWEEN

NISOURCE CORPORATE SERVICES COMPANY

AND

COLUMBIA GAS OF PENNSYLVANIA, INC.

Dated January 1, 2015

(To Take Effect Pursuant to Article 3 Hereof)

SERVICE AGREEMENT

This SERVICE AGREEMENT (the "Service Agreement" or "Agreement") is made and entered into effective the 1st day of January, 2015 by and between Columbia Gas of Pennsylvania, Inc., its subsidiaries, affiliates and associates ("Client", and together with other associate companies that have or may in the future execute this form of Service Agreement, the "Clients") and NiSource Corporate Services Company ("Company").

WITNESSETH:

WHEREAS, each Company and Client is a direct or indirect wholly owned subsidiary of NiSource Inc., a Delaware corporation and a "holding company" as defined in the Public Utility Holding Company Act of 2005 ("Act") that is subject to regulations adopted by the Federal Energy Regulatory Commission ("FERC") pursuant to the Act;

WHEREAS, the Client is an affiliate of the Company; and

WHEREAS, the Company and Client agree to enter into this Service Agreement whereby the Client may seek certain services from the Company and the Company agrees to provide such services upon request and upon the Company's conclusion that it is able to perform such services. Further, the Client agrees to pay for the services as provided herein at the lower of cost or market; and

WHEREAS, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE 1

SERVICES

1.1 The Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in Section 2 of Appendix A hereto (the "Services"), at such times, for such periods and in such manner as Client may from time to time request and that the Company concludes it is able to perform. The Company shall also provide Client with such services, in addition to those services described in Appendix A hereto, as may be requested by Client and that the Company concludes it is able to perform. In supplying such services, the Company may arrange, where it deems appropriate in consultation with Client, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services ("Additional Services").

1.2 Client shall take from the Company such of the Services, and such Additional Services, whether or not now contemplated, as are requested from time to time by Client and that the Company concludes it is able to perform.

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with Exhibit A, which is filed annually with the FERC. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

1.4 The Company shall hire, train and maintain an experienced staff able to perform the Services, or shall obtain experience through third-party resources, as it shall determine in consultation with Client.

1.5 The Company routinely makes payments on behalf of affiliates on an ongoing basis, including payroll, employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate receives on a monthly basis a Convenience Bill 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. Therefore, the Company makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate and not by the Company.

ARTICLE 2

COMPENSATION

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A.

2.2 It is the intent of this Service Agreement that charges for Services shall be billed, to the extent reasonably possible, directly to the Client or Clients benefiting from such Service. Any amounts remaining after such direct billing shall be allocated using the methods identified in Appendix A. The methods of allocation of cost shall be subject to review annually, or more frequently if appropriate. Such methods of allocation of costs may be modified or changed by the Company without the necessity of an amendment to this Service Agreement; provided that, in each instance, all services rendered hereunder shall be at actual cost and include compensation for use of capital thereof, fairly and equitably allocated. The Company shall review with the

Client any proposed change in the methods of allocation of costs hereunder and the parties must agree to any such changes before they are implemented.

2.3 The Company shall make available monthly billing information to the Client that shall reflect all information necessary to identify the costs charged and Services rendered for that month. Client shall undertake a review of the charges and identify all questions or concerns regarding the charges reflected within a reasonable period of time. Client shall remit to the Company all charges billed to it within a period of time not exceeding 30 days of receipt of the monthly billing information.

2.4 Client agrees to provide the Company, from time to time, as requested such financial and statistical information as the Company may need to compute the charges payable by Client consistent with the method of allocation set forth on Appendix A.

2.5 It is the intent of this Service Agreement that the payment for services rendered by the Company to Client under this Service Agreement shall cover all the costs of its doing business including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, insurance, injuries and damages, employee and retiree pensions and benefits, taxes, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and reasonable compensation for use of capital.

ARTICLE 3

TERM

3.1 This Service Agreement shall become effective as of the date first written above, subject only to the receipt of any required regulatory approvals from the State Commissions and federal agencies as needed, and shall continue in force until terminated by the Company or Client, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with (1) the Act or with any rule, regulation or order of the FERC adopted before or after the date of this Service Agreement, or (2) any state or federal statute, or any rule, decision, or order of any state or federal regulatory agency having jurisdiction over one or more Clients. Further, this Service Agreement shall be terminated with respect to the Client immediately upon the Client ceasing to be an associate company of the Company. The parties' obligations under this Service Agreement which by their nature are intended to continue beyond the termination or expiration of this Service Agreement shall survive such termination or expiration.

ARTICLE 4

SERVICE REVIEW

4.1 Upon request of the Client, the Company shall meet with the Client to review and assess the quality, costs, and/or allocations of the services being provided pursuant to this

Service Agreement. The Client shall also have the right to amend the scope of services as it determines to be necessary or desirable.

4.2 NiSource maintains an Internal Audit Department that will conduct periodic audits of the Company administration and accounting processes ("Audits"). The Audits will include examinations of Service Agreements, accounting systems, source documents, methods of allocation of costs and billings to ensure all Services are properly accounted for and billed to the appropriate Client. In addition, the Company's policies, operating procedures and controls will be evaluated annually. Copies of the reports generated by the Company as part of the Audits will be provided to Client upon request.

ARTICLE 5

MISCELLANEOUS

5.1 All accounts and records of the Company shall be kept in accordance with the FERC's Uniform System of Accounts ("USofA") for centralized service companies .

5.2 New direct or indirect subsidiaries of NiSource Inc., which may come into existence after the effective date of this Service Agreement, may become additional Clients of the Company and subject to a service agreement with the Company. The parties hereto shall make such changes in the scope and character of the services to be rendered and the method of allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.2, as may become necessary to achieve a fair and equitable allocation of the Company's costs among all Clients including any new subsidiaries. The parties shall make similar changes if any Client ceases to be associated with the Company.

5.3 The Company shall permit Client reasonable access to its accounts and records including the basis and computation of allocations.

5.4 The Company and Client shall comply with the terms and conditions of all applicable contracts managed by the Company for the Client, individually, or for one or more Clients, collectively, including without limitation terms and conditions preserving the confidentiality and security of proprietary information of vendors.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

NISOURCE CORPORATE SERVICES COMPANY

By: Joseph W. Mulpas
Name: Joseph W. Mulpas
Its: Vice President & Chief Accounting Officer

COLUMBIA GAS OF PENNSYLVANIA, INC.

By: Michael A. Huwar
Name: Michael A. Huwar
Its: President

APPENDIX A

NISOURCE CORPORATE SERVICES COMPANY

Services Available to Clients
Methods of Charging Therefor and
Miscellaneous Terms and Conditions of Service Agreement

ARTICLE 1

DEFINITIONS

1 The term "Company" shall mean NiSource Corporate Services Company and its successors.

2 The term "Service Agreement" shall mean an agreement, of which this Appendix A constitutes a part, for the rendition of services by the Company.

3 The term "Client" shall mean any corporation to which services may be rendered by the Company under a Service Agreement.

ARTICLE 2

DESCRIPTION OF SERVICES

Descriptions of the expected services to be provided by the Company are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The details listed under each heading are intended to be illustrative rather than inclusive and are subject to modification from time to time in accordance with the state of the art and the needs of the Clients.

1 *Accounting and Statistical Services.* The Company will advise and assist the Clients in all aspects of accounting, including financial accounting, asset accounting, regulatory accounting, tax accounting, maintenance of books and records, safeguarding of assets, accounts payable, accounts receivable, reconciliations, accounting research, reporting, operations and maintenance analysis, payroll services, business applications support, and other related accounting functions. The Company will also provide services related to developing, analyzing and interpreting financial statements, directors' reports, regulatory reports, operating statistics and other financial reports. The Company will ensure compliance with generally accepted accounting principles and provide guidance on exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board. The Company will advise and assist the Clients in the formulation of accounting practices and policies and will conduct special studies as may be requested by the Clients.

2 *Auditing Services.* The Company will conduct periodic audits of the general records of the Clients, will supervise the auditing of local and field office records of the Client, and will coordinate the audit programs of the Clients with those of the independent accountants

in the annual examination of their accounts. The Company will ensure compliance, monitor business risk, and coordinate internal control structure.

3 *Budget Services.* The Company will advise and assist the Clients in matters involving the preparation and development of forecasts, budgets and budgetary controls, and other financial planning activities.

4 *Business Services.* The Company will advise and assist the Clients in the preparation and use of educational and advertising materials; in the development of processes to increase residential, commercial and industrial customers, as well as maintenance of business in those areas; and providing information to customers regarding Clients' products and services.

5 *Corporate Services.* The Company will advise and assist the Clients in connection with corporate matters including corporate secretary services, business continuity planning, shareholder services, corporate records management, proceedings involving regulatory bodies, and other corporate matters.

6 *Customer Billing, Collection, and Contact Services.* The Company will render calculating, bill exception processing, back office processing, posting, printing, inserting, mailing and related services to Client associated with the preparation and issuance of customer bills, notices, inserts and similar mailings. The Company will provide cash processing, revenue recovery, account reconciliations and adjustments, and related services to Client associated with the collection of revenue and management of accounts receivable. The Company will provide customer contact and related services to Client, including alternative pricing services, customer contact center management, operation and administration; management of key customer relationships; communications associated with the commencement, transfer, maintenance and disconnection of service; sales of optional products and services; the receipt and processing of emergency calls; the handling of customer complaints; and responses to customer billing, credit, collection, order take and inquiry, outage, meter reading, retail choice and other inquiries.

7 *Depreciation Services.* The Company will advise and assist the Clients in matters pertaining to depreciation practices, including (1) the making of studies to determine the estimated service life of various types of plant, annual depreciation accrual rates, salvage experience, and trends in depreciation reserves indicated by such studies; (2) assistance in the organization and training of the depreciation departments of the Clients; and (3) dissemination to the Clients of information concerning current developments in depreciation practices.

8 *Economic Services.* The Company will advise and assist the Clients in matters involving economic research and planning and in the development of specific economic studies.

9 *Electronic Communications Services.* The Company will advise and assist the Clients in connection with the planning, installation and operation of radio networks, remote control and telemetering devices, microwave relay systems and all other applications of electronics to the fields of communication and control.

10 *Employee Services.* The Company will advise and assist the Clients in connection with organizational, leadership, and strategic development, employee relations matters, including recruitment, employee placement and retention, training, compensation, safety, labor relations

and health, welfare and employee benefits. The Company will also advise and assist the Clients in connection with temporary labor matters, including assessment, selection, contract negotiation, administration, service provider relationships, compliance, review and reporting.

11 *Engineering and Research Services.* The Company will advise and assist the Clients in connection with the engineering phases of all construction and operating matters, including estimates of costs of construction, preparation of plans and designs, engineering and supervision of the fabrication of natural gas facilities, standardization of engineering procedures, and supervision and inspection of construction. The Company will also conduct both basic and specific research in fields related to the operations of the Clients.

12 *Facility Services.* The Company will manage and effectively execute facility operations, facility maintenance, provide suitable space in its offices for the use of the Clients and their officers and employees, provide delivery services, security services, print services, and other facility services.

13 *Gas Dispatching Services.* The Company will advise and assist the Clients in the dispatching of the gas supplies available to the Clients, and in determining and effecting the most efficient routing and distribution of such supplies in the light of the respective needs therefor and the applicable laws and regulations of governmental bodies. If requested by the Clients, the Company will provide a central dispatcher or dispatchers to handle the routing and dispatching of gas.

14 *Information Services.* The Company will advise and assist the Clients in matters involving the furnishing of information to customers, employees, investors and other interested groups, and to the public generally, including the preparation of booklets, photographs, motion pictures and other means of presentation, and assistance to Clients in their advertising programs.

15 *Information Technology Services.* The Company will advise and assist Clients in matters involving information technology, including management, operations, control, monitoring, testing, evaluation, data access security, disaster recovery planning, technical research, and support services. The Company will also provide and assist the Client with application development, maintenance, modifications, upgrades and ongoing production support for a portfolio of systems and software that are used by the Clients. In addition, the Company will identify and resolve problems, ensure efficient use of software and hardware, and ensure that timely upgrades are made to meet the demands of the Clients. The Company will also maintain information concerning the disposition and location of Information Technology assets.

16 *Insurance Services.* The Company will advise and assist the Clients in general insurance matters, in obtaining policies, making inspections and settling claims.

17 *Land/Surveying Services.* The Company will provide land asset management, land contract management, and surveying services in connection with Clients' acquisition, leasing, maintenance, and disposal of interests in real property, including the maintenance of land records and the recording of instruments relating to such interests in real property, where necessary.

18 *Legal Services.* The Company will provide Clients with legal services (including legal services, as necessary or advisable, in connection with or in support of any of the other services provided hereunder), including, but not limited to, general corporate matters and internal corporate maintenance, contract drafting and negotiation, litigation, liability and risk assessment, financing, securities offerings, state and federal regulatory compliance, state and federal regulatory support and rule interpretation and advice, including, without limitation, interpretation and advice concerning the regulations or orders of the Securities and Exchange Commission, the Federal Energy Regulatory Commission, the Environmental Protection Agency, and the Pipeline and Hazardous Materials Safety Administration, bankruptcy and collection matters, employment and labor relations investigations, union contracting, Equal Employment Opportunity Commission issues, compliance with state and federal legislative requirements, and all other matters for which Clients require legal services.

19 *Officers.* Any Client may, with the consent of the Company, elect to any office of the Client any officer or employee of the Company whose compensation is paid, in whole or in part, by the Company. Services rendered to the Client by such person as an officer shall be billed by the Company to the Client and paid for as provided in Articles 3 and 4, and the Client shall not be required to pay any compensation directly to any such person.

20 *Operations Support and Planning Services.* The Company will advise and assist the Clients in connection with operations support and planning, including logistics, scheduling & dispatching; workforce planning; corrosion and leakage programs; estimates of gas requirements and gas availability; gas transmission, measurement, storage and distribution; construction requirements; construction management; operating standards and practices; regulatory and environmental compliance; pipeline safety and compliance; employee and system safety programs; sustainability; training; management of transportation and sales programs; negotiation of gas purchase and sale contracts; energy marketing and trading, including off-system sales and capacity release activities contemplated in a Client's revenue sharing mechanism; security services; measurement, regulation and conditioning equipment; meter testing, calibration and repair; hydraulic gas network modeling, facility mapping and GIS technologies; and other operating matters.

21 *Purchasing, Storage and Disposition Services.* The Company will render advice and assistance to the Clients in connection with supply chain activities, including the standardization, purchase, lease, license and acquisition of equipment, materials, supplies, services, software, intellectual property and other assets, as well as shipping, storage and disposition of same. The Company will also render advice and assistance to the Client in connection with the negotiation of the purchase, sale, acquisition or disposition of assets and services and the placing of purchase orders for the account of the Client.

22 *Regulatory Services.* The Company will advise and assist the Clients in all regulatory and rate matters, including the design and preparation of schedules and tariffs, the analysis of rate filings, the preparation and presentation of testimony and exhibits to regulatory authorities, and other regulatory activities.

23 *Tax Services.* The Company will advise and assist the Clients in tax matters, in the preparation of tax returns and in connection with proceedings relating to taxes.

24 *Transportation Services.* The Company will advise and assist the Clients in connection with the purchase, lease, operation and maintenance of motor vehicles and the operation of aircraft owned or leased by the Company or the Clients.

25 *Treasury Services.* The Company provides services such as risk management, cash management, long and short term financing for all Clients, investment of temporarily available cash, retirement of long term debt, investment management oversight of all benefits plans, and special economic studies as requested.

26 *Miscellaneous Services.* The Company will render to any Client such other services, not hereinabove described, , as from time to time the Company may be equipped to render and such Client may desire to have performed.

ARTICLE 3

ALLOCATION METHODS

1 *Specific Direct Salary Charges to Clients.* To the extent that time spent by the officers and employees of the Company rendering services hereunder is related to services rendered to a specific Client, a direct salary charge, computed as provided in Article 4, shall be made to such Client.

2 *Apportioned Direct Salary Charges to Clients.* To the extent that the time spent by such officers and employees is related to services rendered to the Clients generally, or to any specified group of the Clients, a direct salary charge, computed as provided in Article 4, shall be made to the Clients generally, or to such specified group of the Clients, and allocated to each such Client using an allocation method as set forth on Exhibit A hereto.

3 *Direct Salary Charges for Services to the Company.* To the extent that time spent by any officer or employee of the Company is related to services rendered to the Company, a direct salary charge computed as provided in Article 4 shall be allocated among the Clients in the same proportions which the direct salary charges to such Clients made pursuant to Sections 1 and 2 of this Article III, for services of officers and employees, bear to the aggregate of such direct salary charges.

4 *Apportionment of Employee Benefits.* The employee benefit expenses that are related to direct salary charges made pursuant to sub-paragraphs (1), (2) and (3) of Article 3 shall be apportioned among the Clients, as applicable, in the proportions that the respective direct salary charges made pursuant to the rendering of such services to each such Client bear to the aggregate of such direct salary charges.

5 *Other Expenses.* All expenses, other than salaries and employee benefit expenses incurred by the Company in connection with services rendered to a specific Client shall be charged directly to such Client. All such expenses incurred by the Company in connection with services rendered to the Clients generally or to any specified group of Clients shall be apportioned in the manner set forth in Section 2 of this Article 3 for the apportionment of salary charges. All such expenses incurred by the Company in connection with services rendered to the

Company shall be apportioned in the manner set forth in Section 3 of this Article 3 for the apportionment of salary charges.

ARTICLE 4

COMPUTATION OF SALARY CHARGES

Direct Salary Charges The direct salary charge per hour which shall be made for the time of any officer or employee for services rendered in any calendar month shall be computed by dividing his total compensation for such month by the aggregate of (1) the number of scheduled working hours for which he was compensated, including hours paid for but not worked, and (2) hours worked in excess of his regular work schedule, whether or not compensated for.

Exhibit A

DIRECT BILLING AND BASES OF ALLOCATION

The Company will bill charges directly to a Client to the extent possible while any remaining costs are then allocated. When it is impractical or inappropriate to charge a Client directly, the Company allocates costs in accordance with the following Bases of Allocation which are filed annually with the FERC. The Company works cooperatively with department sponsors or project leaders through meetings and discussions to ensure costs are properly allocated to the Clients that will benefit from the service provided. Provided below are the Bases of Allocation for the Company, including a description of each basis and its numerator and denominator.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 3

NUMBER OF METERS SERVICED

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of meters serviced to the total number of all meters serviced of the benefited affiliates. This allocation may only be used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 4

NUMBER OF ACCOUNTS PAYABLE INVOICES PROCESSED

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of accounts payable invoices processed (interface invoices excluded) to the total number of all accounts payable invoices processed of the benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Charges will be allocated to each benefited affiliate on the basis of the relation of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Charges will be allocated to each benefited affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

➢ Charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 20

SERVICE COMPANY BILLING (DIRECT AND ALLOCATED) COSTS

➢ Charges will be allocated to each benefited affiliate on the basis of the relation of its Service Corporation billing costs, in total or by functional group (e.g. IT, Legal, HR, Finance, Audit), to the corresponding total of all Service Company billing costs, (i.e. in total or by functional group). The calculation of Basis 20 will include only those billings for services provided to all NiSource affiliates, excluding Business Unit specific shared service functions (i.e. functions that serve only one particular Business Unit). All companies may be included in this allocation.

Description	Cost	Comments
Define and implement OJT program for Power Delivery. Current content needs to be updated and tracking tools developed	$ 205,567.70	This is electric training- no CPA costs
Foundational- Establish QAQC for Electric	$ 164,454.16	This is electric training- no CPA costs
Mandatory refresher & competency training for select electric and gas employees Electric- 50% of Power Delivery employees (approx. 200). Scope to combine critical tasks, general orders, OSHA proficiency and input from leaders. 2 day program This program is fully incremental.	$ 266,476.65	This is electric training- no CPA costs
Electric Only Costs	**$ 636,498.50**	

Description	Cost	Comments
Determine TVC record status for 100% of transmission pipeline and 26% of transmission regulator stations	$ 829,393.89	The Station MAOP Reconfirmation Program will enable Columbia to capture and validate the prescribed attribute data associated with transmission class assets located at Columbia's regulator stations in order to address the requirements of the PHMSA Gas Transmission Rule in a manner consistent with PHMSA's current guidance. The required material and pressure test documentation research of regulator stations with transmission class assets will enable Columbia to confirm that the records are traceable, verifiable and complete (TVC) supporting the documented MAOP
Accelerate isometric validation for low pressure and stations with inlet pressure above 125psi	$ 654,784.65	Columbia will accelerate it's efforts to validate and enhance isometric drawings. In 2022, Columbia will focus its efforts on stations with inlet pressures above 125psi with buried control lines. To ensure the detailed documentation of these control lines, Columbia will locate and excavate buried control lines and include the location details on the isometric drawings. Additionally, while at these regulator stations, Columbia will enhance the physical security protection capabilities through the installation of bollards where needed.
Accelerate risk based implementation of Picarro	$ 611,132.34	In 2022, Columbia plans to operate one additional Picarro enabled unit in PA. Surveys will be conducted in targeted pilot areas and will also address large volume leaks, to further Columbia's committment to reduce methane and protect our environment. These costs are assumptions based on the planned mileage, historical average number of potential leak indications requiring inspection per mile, and historical average of the expected number of additional leaks found by the Picarro enabled units per mile.
Foundational- Add QAQC roles throughout Gas Operations. Increase targeted and random programs. Expand ability to provide operational expertise and technical support to operations	$ 639,543.95	The additional positions were determined based on the need to expand Quality Assurance audits and presence across all operating areas and crews. The additional expertise will also review and communicate key quality assessment findings to the company in order to implement corrective action as necessary and advise on improvement opportunities based on compliance and quality findings. The technical expertise will provide independent review, oversight and feedback on our critical gas focused tasks, assuring our safety practices and identifying areas of improvement.
[illegible] employees and reduce speed to mastery. Create refresher training program targeting existing employee. Require all existing M&R employees attend 3 day refresher in 2021. Estimate 200 employees. Bootcamp leverages some existing materials. Refresher programs need to be built. At beginning of 2021 have M&R OJT coaches work with leaders to complete competency assessment of each employee. Needs identified will shape refresher program.	$ 319,771.97	These resources are specifically dedicated to the Measurement & Regulation program. Over the past several years, the company has invested in the Low pressure program. The new M&R Trainers will support the LP project and the recently developed M&R Bootcamp and Refresher program. Beginning in 2021, all M&R employees will be required to attend a 3-4 day refresher program.

Develop and implement gas & electric training curriculum with clear competencies, role clarity and progression criteria, including engineering field observations	$ 218,261.55	NiSource is in the process of building a robust engineering training program for Gas Engineers. These new positions will be dedicated to the development, delivery and oversight of the engineering development program. They will provide support new engineers training as well as competency training for experienced engineers.
Mandatory refresher & competency training for select electric and gas employees Gas- 50% of Plant, Service and Combo employees (approx. 620). Scope to combine critical tasks, common audit findings, new standards and common competency development needs. 3 day program including 1 day of emergency response. This expands gas participation from approximately 20% today to 50%.	$ 266,476.65	These resources are specifically dedicated to the Measurement & Regulation program. Over the past several years, the company has invested in the Low pressure program. The new M&R Trainers will support the LP project and the recently developed M&R Bootcamp and Refresher program. Beginning in 2021, all M&R employees will be required to attend a 3-4 day refresher program.
Foundational: Expand Common OQ to include COH, CKY and contractors in all states. Right-size organization with dedicates resources to eliminate reliance on Training and Technical Support team	$ 239,828.98	CPA impelmented an Operator Qualification program referred to as "Common OQ" is based on the industry standard B31Q definition of covered tasks and brings wtih in an increased level of rigor and specificity. NiSourceis increaseing the program over a 3 year period for employees and contactors. The positions required for CPA will support the increased volume of knowledge and skill evaluations required.
Launch officer development program ("Elevate") to reinforce expectations, build	$ 109,130.77	Per the Monitor Report, NiSoure intends to: 1) Revise mission statements and policy documents to prioritize safety 2) Communicate, educate and align the company around the revised concepts of mission, vision and values 3) Commit to clear accountability for safety by updating corporate governance documents and policies and through enforcement Elevate Program was designed to ensure set safety expectations at the top of the organization, with Officers
Formalize and expand the QMS, governing and measuring compliance and end-to-end quality processes and identifying and correcting deficiencies through a continuous improvement framework	$ 109,130.77	Added resources to the Quality Manament Team to expand capabilities in process management, continous improvement and data analytics. These postions are focused on establishing the strategic focus of the QMS through process reviews and maintaining ISO 9001 certification requirements for the company; and building and measuring process performance excellence through targeted reviews, KPI tracking and exception based reporting on critical, high consequence processes.
Implement Everyday Performance Management training and reinforcement program for all leaders, across NiSource to increase safety leadership capability in setting clear goals, coaching and holding others accountable	$ 87,304.62	Per the Monitor Report, NiSoure intends to: 1) Revise mission statements and policy documents to prioritize safety 2) Communicate, educate and align the company around the revised concepts of mission, vision and values 3) Commit to clear accountability for safety by updating corporate governance documents and policies and through enforcement Everyday Performance Management was designed to increase leader capability to deliver meaningful and actionable coaching conversations and hold people accountable through the lens of safety.
Increase Field Leader Technical Skills Training . Refresh/Complete technical assessment of all FLL to identify competency requirements. Gas program and Training exists Electric program and Training partially exists	$ 91,363.42	Increases to the Front Line Leader development program will include the implementation of "Common OQ" and participating in a new technical training curriculum for leaders.

Retain additional expertise for the Quality Review Board (QRB) in utility operations and quality	$ 65,478.46	Dr Blan Godfrey joined the Quality Review Board in 2021, adding quality management expertise to the advisory board. Blan Godfrey and Chuck Coleman have also joined as active advisors to the Quality Management team, supporting the organization as they establish a QMS grounded in best practices and enabling the company to pursue and expand into future areas ISO 9001 quality certification.
Develop implementation plan to drive adoption and sustainment of our safety culture through communications, learning, cultural expressions and engagement activities	$ 49,108.85	This project is proposed to help assess and, as appropriate, lay out suggestions for improving the cultural underpinnings of this SMS on a State by State basis, as well as to identify any suggestions that may benefit from a corporate-wide implementation. The longer-term objective is to selectively accelerate change, if needed, and more generally to improve understanding of, engagement in, and implementation of the NiSource SMS. Design a cultural assessment methodology, implement this assessment in a standardized way in each of the six NiSource gas State operations, analyze results, and present State by State findings to NiSource at the State and Corporate levels.
Foundational- Expand Welding training program to expand QAQC and direct support of construction large projects	$ 60,908.95	NiSource is developing a new QAQC program to provide oversight and quality assurance for company and contractor welders.
Operationalize MOC process within NiSource for Gas and Electric	$ 43,652.31	Formal management of change process is a requirement of API RP 1173 as a component of Safety Management System implementation. Through external evaluation of our SMS program prior to 2021, lack of a formal management of change process was identified as a gap in the implementation and effectiveness of NiSource's SMS program. NiSource approved and implemented a formal MoC Program and standard intended to bring increased awareness, rigor and documentation to change initiatives that may introduce risk to safety or compliance have been appropriately mitigated prior to implementation. The MoC process requires review and approval of change implementation plans to assure they appropriately support the understanding, adherence and sustainability of changes. Established a Management of Change team adding two FTE roles to headcount within the SMS Strategy & Process Organization to support the organization in the governance and execution of the program which has managed ~45 organizational changes since implementation in December of 2020. Additionally, invested in the development of a Management of Change platform within the Devonway suite of software to ensure effective documentation of changes as well as audit trail of appropriate review and approvals of changes.
Leverage QRB to expand into quality and culture elements	$ 43,652.31	Developing plan for front line employee engagement to support cultural awareness and feedback with members of the review board in the latter half of this year following formal requirements around the use of standard operating procedures for high consequence task work.
Foundational: implement Contractor Training Evaluation program to audit contractor training and qualification program and make recommendations for improvement/alignment with NiSource Evaluation program was designed and piloted in 2019 but not implemented due to COVID restrictions.	$ 26,647.66	NiSource will add 2 new positions to support Contractor Training Evaluations. These resources will be allocated across all companies. In addition to providing direct support to contractors, these trainers will conduct periodic assessments of the contractor training programs and made recommendations for improvement.
Deploy implementation plan for adoption / sustainment in alignment with our leadership enablement, assessment, incentives and performance management practices	$ 10,913.08	Multimedia assets and materials created by a vendor to support culture implementation. As directed by safety monitor, a key challenge we have is in clarity in our culutral expectations. These materials will further educate and sustain our cultural expectations. All employees should be live our cultural values and these materials will support that effort.

Establish detailed approach for measuring progress on maturity of safety culture for continuous improvement	$ 10,913.08	Development of culture maturity dashboard(tableau) by external vendor. An external safety monitor determined that our culture is not consistengly defined and/or monitored. This work will help assess our effrots from a safety management perspective. Further this work will assess our maturity to determine where additional cultural focus is needed, especially as it relates to our culture of care and consistent focus on safety.
SMS Expenses	**$ 4,487,398.26**	

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 8

Question No. OCA 8-006:

Referring to the response to OCA I-37, Attachment A, Tab NCSC, please provide all documentation and workpapers supporting each of the "SMS Expenses" comprising the safety plan.

Response: Please see Attachment A.

Description	Cost
Determine TVC record status for 100% of transmission pipeline and 26% of transmission regulator stations	$ 829,393.89
Accelerate isometric validation for low pressure and stations with inlet pressure above 125psi	$ 654,784.65
Accelerate risk based implementation of Picarro	$ 611,132.34
Foundational- Add QAQC roles throughout Gas Operations. Increase targeted and random programs. Expand ability to provide operational expertise and technical support to operations	$ 639,543.95
Rebuild M&R/GM&T training program to recognize increased volume of new employees and reduce speed to mastery. Create refresher training program targeting existing employee. Require all existing M&R employees attend 3 day refresher in 2021. Estimate 200 employees. Bootcamp leverages some existing materials. Refresher programs need to be built. At beginning of 2021 have M&R OJT coaches work with leaders to complete competency assessment of each employee. Needs identified will shape refresher program.	$ 319,771.97
Develop and implement gas & electric training curriculum with clear competencies, role clarity and progression criteria, including engineering field observations	$ 218,261.55
Mandatory refresher & competency training for select electric and gas employees Electric- 50% of Power Delivery employees (approx. 200). Scope to combine critical tasks, general orders, OSHA proficiency and input from leaders. 2 day program This program is fully incremental.	$ 266,476.65
Mandatory refresher & competency training for select electric and gas employees Gas- 50% of Plant, Service and Combo employees (approx. 620). Scope to combine critical tasks, common audit findings, new standards and common competency development needs. 3 day program including 1 day of emergency response. This expands gas participation from approximately 20% today to 50%.	$ 266,476.65
Foundational: Expand Common OQ to include COH, CKY and contractors in all states. Right-size organization with dedicates resources to eliminate reliance on Training and Technical Support team	$ 239,828.98
Define and implement OJT program for Power Delivery. Current content needs to be updated and tracking tools developed	$ 205,567.70
Foundational- Establish QAQC for Electric	$ 164,454.16
Launch officer development program ("Elevate") to reinforce expectations, build co	$ 109,130.77
Formalize and expand the QMS, governing and measuring compliance and end-to-end quality processes and identifying and correcting deficiencies through a continuous improvement framework	$ 109,130.77
Implement Everyday Performance Management training and reinforcement program for all leaders, across NiSource to increase safety leadership capability in setting clear goals, coaching and holding others accountable	$ 87,304.62
Increase Field Leader Technical Skills Training . Refresh/Complete technical assessment of all FLL to identify competency requirements. Gas program and Training exists Electric program and Training partially exists	$ 91,363.42
Retain additional expertise for the Quality Review Board (QRB) in utility operations and quality	$ 65,478.46
Develop implementation plan to drive adoption and sustainment of our safety culture through communications, learning, cultural expressions and engagement activities	$ 49,108.85
Foundational- Expand Welding training program to expand QAQC and direct support of construction large projects	$ 60,908.95
Operationalize MOC process within NiSource for Gas and Electric	$ 43,652.31
Leverage QRB to expand into quality and culture elements	$ 43,652.31
Foundational: implement Contractor Training Evaluation program to audit contractor training and qualification program and make recommendations for improvement/alignment with NiSource Evaluation program was designed and piloted in 2019 but not implemented due to COVID restrictions.	$ 26,647.66
Deploy implementation plan for adoption / sustainment in alignment with our leadership enablement, assessment, incentives and performance management practices	$ 10,913.08
Establish detailed approach for measuring progress on maturity of safety culture for continuous improvement	$ 10,913.08
SMS Expenses	**$ 5,123,896.76**

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 8

Question No. OCA 8-007:

Referring to the response to OCA I-37, Attachment A, Tabs OCA I-37 and OCA I-38, please provide all documentation and workpapers supporting the increase in Other Employee Benefits.

Response: Please see Attachment A to this response. An inflation factor was applied to the FTY to determine the FPFTY amounts.

NiSource Inc. Benefit Plans for the Period 2020 through 2025 ($000)
Columbia Gas of Pennsylvania

	2020		2021		2022		2023		2024		2025	
Cash Estimates by Plan:	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current
Retirement	$ -	$ -	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 1,283	$ 10		$ 10
D.C.	3,543	3,427	3,650	3,559	3,760	4,038	3,872	4,159	3,988	4,284		4,413
Medical Active*	7,960	7,357	8,742	8,074	9,593	8,880	10,520	9,754	11,475	10,703		11,734
Medical Active HSA	320	395	320	395	320	395	320	395	320	395		395
Medical Retiree	33	32	32	28	29	26	27	24	25	22		21
Dental	423	456	436	473	449	487	462	502	476	517		533
Group Life Active	206	271	212	279	219	287	225	296	232	305		314
Group Life Retiree	-	-	-	-	-	-	-	-	-	-		-
Long Term Disability	327	360	337	371	347	382	357	394	368	405		418
Value Options**	12	13	12	13	12	13	12	13	12	13		14
Opt Out Credits	165	180	165	180	165	180	165	180	165	180		180
Vision	79	85	82	84	82	84	85	84	85	87		87
Total	$ 13,068	$ 12,576	$ 13,998	$ 13,466	$ 14,986	$ 14,782	$ 16,055	$ 15,811	$ 18,429	$ 16,921		$ 18,119

	2020		2021		2022		2023		2024		2025	
Expense Estimates by Plan:	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current
Retirement	$ 3,227	$ 2,643	$ 2,913	$ 2,221	$ 2,587	$ 1,974	$ 2,185	$ 1,679	$ 1,791	$ 1,365		$ 1,323
Qualified	830	150	593	(242)	400	(369)	250	(466)	92	(532)		(589)
Settlements	2,388	2,484	2,310	2,456	2,178	2,336	1,927	2,139	1,691	1,891		1,907
SERP	9	9	10	7	9	7	8	6	8	6		5
D.C.	3,563	3,465	3,670	3,942	3,780	4,060	3,893	4,182	4,010	4,308		4,437
Savings Plan Match	2,896	3,109	2,983	3,203	3,073	3,299	3,165	3,398	3,260	3,500		3,605
Profit Sharing	667	356	687	739	707	761	728	784	750	808		832
Medical	7,842	7,344	8,571	8,152	9,384	8,937	10,271	9,787	11,195	10,721		11,736
Active*	7,960	7,357	8,742	8,074	9,593	8,880	10,520	9,754	11,475	10,703		11,734
Active HSA	320	395	320	395	320	395	320	395	320	395		395
Retiree	(438)	(408)	(491)	(317)	(529)	(338)	(569)	(362)	(600)	(377)		(393)
Dental	423	456	436	473	449	487	462	502	476	517		533
Group Life	197	333	189	410	181	396	171	383	166	374		365
Active	206	271	212	279	219	287	225	296	232	305		314
Retiree	(9)	62	(23)	131	(38)	109	(54)	87	(66)	69		51
Long Term Disability	327	360	337	371	347	382	357	394	368	405		418
Value Options**	12	13	12	13	12	13	12	13	12	13		14
Opt Out Credits	165	180	165	180	165	180	165	180	165	180		180
Vision	79	85	82	84	82	84	85	84	85	87		87
TOTAL	$ 15,835	$ 14,879	$ 16,375	$ 15,846	$ 16,987	$ 16,513	$ 17,601	$ 17,204	$ 18,268	$ 17,970		$ 19,093

* Includes medical, RX, administrative fees, and PCORI fees.
** Includes EAP and Work Life.

Support for $8M Other Benefits

13.8	Gross
8.0	Net*

*Capitalization based on 2019 actuals

Fw: July 2020 Benefit Cost Projections
Lacey Doles
to:
Anthony Macioce, Kyle Upchurch
07/02/2020 09:34 AM
Hide Details
From: Lacey Doles/NCS/Enterprise
To: Anthony Macioce/NCS/Enterprise@NISOURCE, Kyle Upchurch/NCS/Enterprise@NISOURCE,

1 Attachment

20200701_NiSource Jul 2020 Projections_Report Exhibits.xlsx

Tony - For our plan update, let me know if all the pieces we need are there and Kyle this is just an FYI that we received this info. I don't think you need it for anything, but wanted to keep you in the loop.

Thanks!

Lacey J. Doles, CPA | Manager - Financial Planning & Analysis
NiSource, Inc. | 240 West Nationwide Blvd. | Columbus, Ohio 43215
Office: (614) 460-4696 | Cell: (614)493-8453

----- Forwarded by Lacey Doles/NCS/Enterprise on 07/02/2020 09:33 AM -----

From: Francesca Crotty <francesca.crotty@aon.com>
To: "ldoles@nisource.com" <ldoles@nisource.com>
Cc: Bridget F Gainer <bridget.francis.gainer@aon.com>, Ivan Yen <ivan.yen@aon.com>, Cheryl Davis <cheryl.davis@aon.com>, Anela Rathi <anela.rathi@aon.com>, Nick Craig <nick.craig@aon.com>, Derek Rylicki <derek.rylicki@aon.com>
Date: 07/01/2020 09:52 PM
Subject: RE: July 2020 Benefit Cost Projections

ATTENTION: This email was sent from a Trusted External Vendor. Please proceed with caution when clicking links or opening attachments.

Hi Lacey,

As a follow up to the email below, we wanted to provide you with an excel version of the by company exhibits included in the report. The results in the attached excel file are in line with the PDF version previously provided.

Let us know if you have any questions or need anything else.

Thanks,
Francesca

Francesca Saporito Crotty, FSA, EA
Aon
200 E. Randolph | Chicago, IL 60601
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francesca.crotty@aon.com | aon.com

From: Francesca Crotty

Sent: Wednesday, July 01, 2020 8:30 PM
To: ldoles@nisource.com
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Subject: July 2020 Benefit Cost Projections

Hi Lacey –

The attached document contains the updated benefit cost projections for 2020 to 2025 on a cash and GAAP expense basis. The following is included in the report:

- Updated retirement cost projections (assumptions and methodologies used are outlined in the report)
- Updated active benefit cost projections (provided by our health and welfare group)
- Updated DC cost projections (provided by NiSource HR)
- Prior results from June 2019 cost projections for 2020 through 2024

In addition, we have attached the following supplemental exhibits (Excel and PDF):

- Summary of ongoing expense components for each year
    - This exhibit breaks out the projected ongoing expense by Service Cost, Interest Cost, and “Other”
    - Note that this exhibit is for ongoing expense only and it excludes settlement/curtailment charges
- Summary of (A)PBO, fair value of assets and funded status by company for each year

Please let us know if you have any questions or need any additional information.

Thanks,
Francesca

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(See attached file: 20200701_NiSource Jul 2020 Projections_Report Exhibits.xlsx)

NiSource Inc. Benefit Plans for the Period 2020 through 2025 ($000)
Columbia Gas of Pennsylvania

	2020		2021		2022		2023		2024		2025	
Cash Estimates by Plan:	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current
Retirement	$ -	$ -	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 1,283	$ 10		$ 10
D.C.	3,543	3,427	3,650	3,559	3,760	4,038	3,872	4,159	3,988	4,284		4,413
Medical Active*	7,960	7,357	8,742	8,074	9,593	8,880	10,520	9,754	11,475	10,703		11,734
Medical Active HSA	320	395	320	395	320	395	320	395	320	395		395
Medical Retiree	33	32	32	28	29	26	27	24	25	22		21
Dental	423	456	436	473	449	487	462	502	476	517		533
Group Life Active	206	271	212	279	219	287	225	296	232	305		314
Group Life Retiree	-	-	-	-	-	-	-	-	-	-		-
Long Term Disability	327	360	337	371	347	382	357	394	368	405		418
Value Options**	12	13	12	13	12	13	12	13	12	13		14
Opt Out Credits	165	180	165	180	165	180	165	180	165	180		180
Vision	79	85	82	84	82	84	85	84	85	87		87
Total	$ 13,068	$ 12,576	$ 13,998	$ 13,466	$ 14,986	$ 14,782	$ 16,055	$ 15,811	$ 18,429	$ 16,921		$ 18,119

	2020		2021		2022		2023		2024		2025	
Expense Estimates by Plan:	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current	Prior	Current
Retirement	$ 3,227	$ 2,643	$ 2,913	$ 2,221	$ 2,587	$ 1,974	$ 2,185	$ 1,679	$ 1,791	$ 1,365		$ 1,323
Qualified	830	150	593	(242)	400	(369)	250	(466)	92	(532)		(589)
Settlements	2,388	2,484	2,310	2,456	2,178	2,336	1,927	2,139	1,691	1,891		1,907
SERP	9	9	10	7	9	7	8	6	8	6		5
D.C.	3,563	3,465	3,670	3,942	3,780	4,060	3,893	4,182	4,010	4,308		4,437
Savings Plan Match	2,896	3,109	2,983	3,203	3,073	3,299	3,165	3,398	3,260	3,500		3,605
Profit Sharing	667	356	687	739	707	761	728	784	750	808		832
Medical	7,842	7,344	8,571	8,152	9,384	8,937	10,271	9,787	11,195	10,721		11,736
Active*	7,960	7,357	8,742	8,074	9,593	8,880	10,520	9,754	11,475	10,703		11,734
Active HSA	320	395	320	395	320	395	320	395	320	395		395
Retiree	(438)	(408)	(491)	(317)	(529)	(338)	(569)	(362)	(600)	(377)		(393)
Dental	423	456	436	473	449	487	462	502	476	517		533
Group Life	197	333	189	410	181	396	171	383	166	374		365
Active	206	271	212	279	219	287	225	296	232	305		314
Retiree	(9)	62	(23)	131	(38)	109	(54)	87	(66)	69		51
Long Term Disability	327	360	337	371	347	382	357	394	368	405		418
Value Options**	12	13	12	13	12	13	12	13	12	13		14
Opt Out Credits	165	180	165	180	165	180	165	180	165	180		180
Vision	79	85	82	84	82	84	85	84	85	87		87
TOTAL	$ 15,835	$ 14,879	$ 16,375	$ 15,846	$ 16,987	$ 16,513	$ 17,601	$ 17,204	$ 18,268	$ 17,970		$ 19,093

* Includes medical, RX, administrative fees, and PCORI fees.
** Includes EAP and Work Life.

Support for $8M Other Benefits

13.8	Gross
8.0	Net*

*Capitalization based on 2019 actuals

COLUMBIA STATEMENT NO. 9-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	

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

July 30, 2021

Q. Please state your name and business address.

A. Nicole M. 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. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your Rejoinder testimony?

A. The purpose of my rejoinder testimony is to address an error in headcount in my rebuttal testimony at Columbia Statement No. 9-R. Further, I will address OCA witness Effron's assertion that detail supporting the change increased allocation factors of NiSource Corporate Services (NCSC) costs have not been provided.

Q. Please explain the error in headcount in your rebuttal.

A. On page 5 of Columbia Statement 9-R, headcount is 774 employees, which inadvertently includes 15 employees on disability or other long term leave. The correct headcount should be 759 employees.

Q. Does this correction in employee headcount alter the Company's position to OCA witness Effron's proposed headcount reduction? Please explain.

A. No. As noted in my rebuttal testimony, 15 applicants have accepted positions with the Company and are in the hiring process, and the Company will continue the wave hiring process in August and October of 2021. The Company expects similar results in the August and October timeframe, thereby advancing headcount toward the 811 target in the case.

Q. On page 14 of OCA Witness Effron's surrebuttal testimony, he states the calculation supporting the increased allocation factor for NCSC expense was not provided. Is this an accurate statement?

A. No. In OCA 10-6, I specifically acknowledge that the calculation was not directly provided in my rebuttal testimony, rather, it was provided in the response to OCA 8-5. Responses to both data requests have been attached to my testimony as Exhibits NP-1RJ and NP-2RJ, respectively.

Q. Does this complete your Prepared Rejoinder Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 10

Question No. OCA 10-006:

Referring to Columbia Statement No. 9-R, Page 16, Lines 20-21, please cite specifically where Exhibit NP-5R clearly shows how the increases in allocation factors were calculated.

Response: Upon further review of Exhibit NP-5R, the Company determined that the exhibit did show the increase, but not the calculation. The calculation was provided in the Response to OCA 8-5.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 8

Question No. OCA 8-005:

Referring to the response to OCA I-37, Attachment A, Tab NCSC, please provide all documentation and workpapers supporting the effect of the CMA sale on the allocation percentages.

Response: Corporate Services costs are calculated systemically based on costs and allocation factors. Subsequent to the sale of CMA, costs were allocated to one less company, causing the NCSC costs to increase to the remaining companies. See below for the calculated percentage impact identified in OCA 1-37.

	FY2019	**FY2021**	**Increase/Decrease**
Columbia Gas of Pennsylvania	$64,254,002	$79,189,029	$14,935,027
Operating Companies	$461,079,466	$478,038,053	$16,958,587
Percentage Impact	13.94%	*16.57%	2.63%

*Difference between 16.41% change per OCA 1-37 and 16.57% herein due to rounding.

J. HARDING

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021- 3024296
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

Q. Please state your name and business address.

A. My name is Jennifer Harding. 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 Director, Income Tax Operations at NCSC.

Q. Please briefly describe your professional experience.

A. I began my career with KPMG as a Senior Associate in the tax department in Baltimore, Maryland in 2005. In 2009, I joined Constellation Energy as a Tax Manager responsible for all aspects of income tax and non-income tax for the generation segment and managed the IRS Federal income tax audit CAP ("Compliance Assurance Process") program. Constellation was acquired by Exelon Corporation in 2012, and I moved to Chicago, Illinois as the Tax Manager of the electric utility responsible for income tax accounting, forecasting income taxes, and income tax and non-income tax return filings. In 2014, I moved to the Netherlands and worked for Mead Johnson Nutrition BV as the Tax Manager for the European region with responsibility for all aspects of income tax and non-income tax accounting, tax research and tax return filings. In 2016, I moved to Columbus, Ohio and worked for Cardinal Health as the Director of International Tax Operations with a responsibility for income tax accounting, forecasting, mergers & acquisitions, tax research and tax return filings in Cardinal Health's foreign jurisdictions. In 2018, I worked as the Head of Tax for Hyperion Materials

& Technologies with full responsibility for all global income and non-income tax accounting, tax return filings, research, mergers & acquisitions and forecasting. In January 2020, I joined NiSource in my current position.

Q. Please describe your educational background.

A. I received a Bachelor in Business Administration with a concentration in Accounting in 2007 from the Notre Dame of Maryland University in Baltimore, Maryland.

Q. What are your responsibilities in your current position?

A. In my current position as Director of Tax Operations, I am responsible for the operational income tax activities for NiSource Inc. and Subsidiaries, including Columbia Gas of Pennsylvania ("Columbia" or "the Company"). My responsibilities include oversight and review of the preparation of income tax accrual and deferred tax entries, forecasting income taxes, preparation and filing income tax returns, technical income tax research and 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") and the Public Service Commission of Maryland.

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 and incorporation of the effects of the enacted Tax Cuts and Jobs Act of 2017. The income tax calculations are included in Exhibit 7 for the Historic Test Year (the twelve month period ending November 30, 2020) and Exhibit 107 for the Future Test Year (the twelve month period ending November 30, 2021) and Fully Projected Future Test Year (the twelve-month period ending December 31, 2022). 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 in effect for the Historic Test Year is 21%. The federal tax rate of 21% has also been reflected for the Future Test Year and the Fully Projected Future Test Year. 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. I acknowledge that the Biden Administration is anticipated to offer a proposal to increase federal corporate income tax rates. Columbia has not reflected any assumption of an increase in federal income tax rates in this case. However, later in my testimony I explain a proposed rider mechanism to adjust rates for changes in federal income tax rates.

Q. Can you explain the flow-through items included in the tax provision and impacts of the TCJA of 2017?

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, the normalization method of accounting prevents utilities from recognizing a reduction in current taxes resulting from the application of accelerated tax depreciation to be immediately recognized as flow-through to utility ratepayers under the Internal Revenue Code. 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 Pennsylvania Public Utility Commission's ("Commission") order in Docket No. R-832493. For the Historic Test Year, the Company has very little in terms of tax depreciation remaining on pre-1981 assets. Thus, Columbia is in a turnaround position, since book depreciation is now higher than tax depreciation. In addition, the Company has excess accumulated deferred income taxes that were originally computed at higher federal tax rates (namely 46% federal tax rate for asset vintages 1981-1987 and 35% federal tax rate for asset vintages 1988-2017) compared to the corporate income tax rate of 21%, a result of the enactment of TCJA of 2017, that are being refunded in rates under the Average Rate Assumption Method ("ARAM"). ARAM is the method under which the excess in the reserve for deferred income taxes is reduced over the remaining lives of the property as used in its books of account that gave rise to the reserve for deferred income taxes and flow-through the amortization of the excess accumulated deferred income taxes. Because most of the book versus tax differences related to assets that were 15 or 20 year property for federal tax purposes and there were multiple years of bonus depreciation since

2001, the excess is in a turnaround situation. There is a variable nature inherent in ARAM, which does not result in an amount that is fixed in every period due to factors such as changes in capital additions, depreciation rates, future retirements and the vintages of those retirements. The Company projects to record lower tax expense of $3,841,826 in its federal tax provision related to the excess accumulated deferred income taxes on asset vintages 1981-2017 for the Fully Projected Future Test Year.

Q. Are there any other deferred taxes that are impacted by the TCJA?

A. Yes, the Company also has deferred taxes for the Federal net operating loss ("NOL"), customer advances, inventory and other book vs. tax timing differences. The federal rate reduction creates net deficient deferred taxes that were originally computed at a 35% federal tax rate for these assets that are reversing at a 21% federal tax rate. For the Federal NOL, the Company includes the recovery of the deficient deferred taxes over the estimated remaining life of the assets of 42 years based on a composite book depreciation rate of 2.4% as included in the last base rate case and projects to record higher tax expense in the amount of $571,394 for the Fully Projected Future Test Year. For the non-property related deferred taxes on customer advances and inventory that are included in the calculation of rate base, the Company projects to record higher tax expense in its federal tax provision by $626,961, using a ten-year amortization period for the Fully Projected Future Test Year. The remaining non-property deferred taxes on book vs. tax timing differences are a net deferred tax asset which results in a net deficient deferred taxes as a result of TCJA. It is the Company's position that because those deferred taxes were not included in the calculation of rate base, the Company is not seeking recovery of the deficient deferred taxes resulting from the decrease in the federal income tax rate.

Q. How does the 2008 change in method of accounting for repairs impact Columbia's taxable income in the rate-making process?

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 rates as established in Columbia's 2010 rate case) the federal repairs deduction is being normalized under deferred tax accounting, so there will be no impact on total federal tax expense. However, the repairs deduction has not been normalized, based on prior Commission orders, and is flow-through for state tax purposes and is reflected in the state 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. A permanent difference results when revenue (gain) or expense (loss) is recognized in book accounting but not recognized under the rules of the Internal Revenue Code, or vice versa. Permanent items increasing tax expense as a result of being non-deductible include expenses for a portion of business meals and employee stock purchase plan compensation reflected in the total flow-through adjustments on

Exhibit 107, Page 16, Line 15.

Q. How has the Company handled Pennsylvania Corporate Net Income Taxes in its calculation of deferred income taxes for property?

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. The Company is not permitted to claim the benefit of Federal bonus depreciation deductions that have been taken in years prior to 2018 in the Pennsylvania corporate tax 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 $144,975,996 net operating loss for 2008 that was carried forward to future years. The Company reduced its Pennsylvania taxable income by 15% of taxable income in 2009. The Company also had a $3,663,502 net operating loss for 2010 and a $69,764,304 net operating loss for 2011 that were carried forward to future years. For tax years in 2015 and 2016, the Company was 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. In October 2017, the Pennsylvania Supreme Court held that the flat-dollar cap on the NOL deduction violated the Uniformity Clause of the Pennsylvania Constitution[1] thereby affirming

[1] *Nextel Communications of the Mid-Atlantic, Inc. v. Commonwealth*, 171 A.3d 682 (Pa. 2017).

the Commonwealth Court of Pennsylvania decision in 2015[2]. The Pennsylvania Supreme Court ordered that the flat-dollar cap of $5 million be removed. In anticipation of the Pennsylvania Supreme Court ruling, the Pennsylvania House of Representatives passed House Bill ("HB") 542, which included a provision that removes the $5 million cap on NOL deductions and increases the current cap of 30% of taxable income to 35% for tax year 2018 and 40% for tax year 2019 and future years. On October 30, 2017, Pennsylvania Governor Tom Wolf signed HB542 into law. In response to the decision, the Pennsylvania Department of Revenue has revised its forms and procedures to eliminate the $5 million flat-dollar cap. The Company's claimed tax expense takes into account the increased NOL limitation of 40% of state taxable income in the Future Test Year and the Fully Projected Future Test Year (Exhibit 107, Page 17, Line 6). The Pennsylvania NOL carryforward is reflected on Exhibit 7, Page 23.

Q. Does the Company's proposed revenue requirement reflect a consolidated tax adjustment?

A. No. The passage of Act 40, 66 Pa. C.S. § 1301.1, which became effective August 10, 2016, eliminated the consolidated tax adjustment in ratemaking. Title 66 of the Pennsylvania Consolidated Statues Section 1301.1 states that for the computation of income tax expense for ratemaking purposes, if an expense or investment is not allowed to be included in a public utility's rates, the tax losses of a public utility's parent or affiliated companies should not be included in computation of income

[2] *Nextel Communications of the Mid-Atlantic, Inc., v. Commonwealth*, 129 A.3d 1 (Pa. Commw. 2015).

tax expense to reduce rates. However, Section 1301.1(b) requires a public utility seeking to change rates to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes. The Company prepared Exhibit No. 7, Pages 2 through 4 for the computation of the Section 1301.1 differential and details of the income and losses of affiliated companies for the periods 2017 to 2019. The Company computed what the consolidated tax expense adjustment would have been by dividing the 3-year average of Columbia's Federal taxable income of $19.8 million by the 3-year average of the Federal taxable income of the consolidated group members with taxable income of $269.8 million to determine the percentage of Columbia's of 7%. This percentage was multiplied by the 3-year average of Federal taxable loss of the adjusted consolidated group members with taxable loss of $280.5 million. The consolidated group member Federal taxable loss was adjusted to exclude Federal taxable losses attributed to Bay State Gas Company and Northern Indiana Public Service Company for tax years 2017 and 2018. The losses were excluded since the assets of Bay State Gas Company were sold in 2020 and losses recognized by Northern Indiana Public Services Company are not expected to continue as they primarily related to accelerated depreciation deductions. Columbia's allocation of Federal taxable loss companies is $20.6 million tax effected at 21% resulting in a 1301.1(b) differential of $4.3 million.

Q. Does the Company's rate case claim support the conclusion that it is

using at least 50 percent of the amount that would have been a consolidated tax adjustment prior to Act 40 to support reliability or infrastructure related capital investment?

A. Yes, as depicted in GAS-RR-014 and discussed in the direct testimony of Witness R. Brumley (Columbia St. No. 7), Columbia's pro forma capital additions for reliability or infrastructure projects are $260.8 million in the FTY and $289.1 million in the FPFTY. This expenditure level is greater than 50% of the amount of $4.3 million that would have been a consolidated tax adjustment prior to Act 40 of 2016.

Q. Does the Company's rate case claim support the conclusion that it is using at least 50 percent the amount that would have been a consolidated tax adjustment prior to Act 40 to support the amount of the revenue requirement attributed to general corporate purposes?

A. Yes, as depicted in Exhibit 102, Schedule 3, Page 3, Line 18 and discussed in direct testimony of Witness K.K. Miller, Columbia's pro forma operating and maintenance budget is $217.5 million in the FTY and $224.7 million in the FPFTY. This expenditure level is greater than 50% of the amount of $4.3 million that would have been a consolidated tax adjustment prior to Act 40 of 2016.

Q. Can you summarize the impact of your testimony on historic and proposed income tax expense?

A. Yes, for the Historic Test Year, Exhibit 7, Page 19, Line 38 delineates total pro forma tax expense of $39,377,172. This total includes $6,001,345 of state income taxes (Exhibit 7, Page 19, Line 37), which is based on $213,676,833 of operating income (Exhibit 7, Page 19, Line 1) less $40,323,744 of interest expense on debt (Exhibit 7, Page 19, Line 9) for total pre-tax income of $173,353,089 resulting in an effective state income tax rate of 3.46%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 9.99%, is a result of the flow through treatment of repairs deductions and loss carryforward deductions for state income tax purposes. The expense for federal income taxes is $33,375,827 (Exhibit 7, Page 19, Line 36) resulting in an effective tax rate of 19.25%. The decreased federal effective tax rate, as compared to the federal statutory rate of 21%, is largely attributable to the flow-through of the amortization of excess accumulated deferred income taxes related to the reduction of the corporation federal income tax rate from 35% to 21% as a result of the enactment of TCJA of 2017.

Q. Please continue with respect to the Fully Projected Future Test Year.

A. For the Fully Projected Future Test Year, Exhibit 107, Page 16, Line 38 delineates total tax expense of $23,206,708. This total includes $1,275,726 of state income taxes (Exhibit 107, Page 16, Line 37), which is based on $161,439,628 of operating income (Exhibit 107, Page 16, Line 1) less $51,589,133 of interest expense on debt (Exhibit 107, Page 16, Line 9) for total pre-tax income of $109,850,495 resulting in an effective state income tax rate of 1.16%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 9.99%, is a result of the flow through treatment of the repairs deductions and loss carryforward deductions for state income tax purposes. The expense for federal income taxes is $21,930,982 (Exhibit 107, Page 16, Line 36) resulting in an effective tax rate of 19.96%. The decreased federal effective tax rate, as compared to the federal statutory rate of

21%, is largely attributable to the flow-through of the amortization of excess accumulated deferred income taxes related to the reduction of the corporation federal income tax rate from 35% to 21% as a result of the enactment of TCJA of 2017.

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 Projected Future Test 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 Commission-approved 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 16, Line 20.

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 NOL, which represents the remaining balance of un-utilized net operating loss, is $ 34,637,164 as shown in Exhibit 7, Page 9. The Company has incurred a tax loss for federal purposes in tax years 2008, 2010, 2011, 2012, 2013, 2016 and 2017, 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. 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 for the Fully Projected Future Test Year is primarily due to repairs and accelerated depreciation deductions. Due to the net operating losses generated by bonus depreciation deductions in the aforementioned years and the modifications to the Federal NOL under the TCJA, the expectation is that the Company will not utilize all of its net operating losses until beyond the Fully Projected Future Test Year. Therefore, there is an increase to rate base on Exhibit 107, Page 5a.2, of $31,978,769 as a deferred tax asset for the amount of unutilized net operating loss for the Fully Projected Future Test Year.

Q. Please explain the adjustment to deferred taxes for the Fully Projected Future Test 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 $10,523,251 computed on Exhibit 107, Page 5b.

Q. Are you sponsoring any other expense adjustments?

A. Yes. I am also sponsoring adjustments for Federal Insurance Contribution Act ("FICA") Tax, Property 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 labor charged to O&M (See Exhibit No. 4, Schedule 1, Page 2 Lines 1 and 2). An increase in payroll taxes of $232,939 is reflected in the annualized Historic Test Year presented on Exhibit No. 6, Schedule 2, Page 3 for the calculation. For the Fully Projected Future Test Year, the Company is projecting a higher payroll base, thus increasing payroll taxes by $29,562 as reflected on Exhibit No. 106, Schedule 2, Page 3 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, 2019. The West Virginia tax for gas stored underground was developed using the December 31, 2019 assessed value and the 2019 tax rate. This annualized level is equal to the Historic Test Year level of $523,822, as shown on Exhibit 6, Schedule 2, Page 4, Line 6. The detail supporting this calculation for the Fully Projected

Future Test Year is provided on Exhibit 106, Schedule 2, Page 4. The pro forma Fully Projected Future Test Year reflects a downward adjustment of $59,918 from the annualized level as a result of using the December 31, 2019 assessed value and the 2019 tax rate which is the latest available at this time.

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 $625 was not adjusted for the Historic Test Year. The pro forma Fully Projected Future Test Year was also not adjusted from this level.

Q. Are you sponsoring any other tax matters?

A. Yes. I am also sponsoring the illustrative calculations, methodology and mechanism developed for a Federal Tax Reform Adjustment (FTRA) tariff that is referenced in Witness R. Danhires testimony to prospectively apply a positive or negative percentage adjustment for the impact of a future increase or decrease of the Federal income tax rate to customer bills as a result of future Federal Tax Reform.

Q. Why are you requesting the new FTRA tariff?

A. The enactment of the TCJA taught us that Federal income tax rate changes can be very material and take effect abruptly resulting in volatility that is completely outside of the Company's control. Accordingly, the Company's is taking a proactive approach to account for the impact of future increase or decrease in Federal income tax rates based on "lessons learned" from the enactment of the TCJA.

Q. How does the Company expect to compute the impact of future increase or decrease in the Federal income tax rate and what is the mechanism developed by the Company?

A. The Company notes that an increase or decrease in the Federal income tax rate based on tax reform would result in a recovery from customers or pass back to customers related to the increase of income tax expense or reduction of income tax expense, respectively. Currently, the Company does not have an indication of the timing of enactment or confirmation of changes in the Federal income tax rate that have been proposed by the Biden Administration. However, to alleviate the administrative burden and lag in timing, the Company is proposing a Federal Tax Reform Adjustment (FTRA) rider to prospectively apply a positive or negative percentage adjustment for the impact of a future increase or decrease of the Federal income tax rate to customer bills as a result of Federal Tax Reform.

The Company has prepared illustrative schedules utilizing a scenario of a 7% increase in the Federal income tax rate from 21% to 28% proposed by the Biden administration using an effective date of January 1, 2022 for illustrative purposes. These schedules are provided with my testimony as Exhibit JH-1. There are two components of tax expense impacted from a change in the Federal income tax rate that the Company has captured in illustrative schedules based on computations of the fully projected future test year ended December 31, 2022: 1) total current and deferred tax expense included in the cost of service and 2) accumulated deferred income taxes (ADIT) included in the rate base which represent future deductible or taxable statutory book/tax temporary differences.

The total Federal income tax expense is comprised of current Federal income tax expense, deferred Federal income tax expense, excess ADIT amortization, deficient ADIT amortization and Federal investment tax credits. The current Federal income tax expense is computed based on Federal taxable income which is the product of pre-tax income, plus statutory permanent and flow-through book/tax differences, plus statutory temporary book/tax differences, less the state tax deduction, multiplied by the Federal income tax rate (See Exhibit JH-1, Attachment A, Page 1, Lines 1 through 17). The deferred Federal income tax expense is computed based on the future deductible or taxable statutory temporary book/tax differences multiplied by the Federal income tax rate (See Exhibit JH-1, Attachment A, Page 1, Line 18). As depicted in the illustrative schedule Attachment A, Page 1, Column H, Lines 17 and 18, the proposed increase in the tax rate results in an increase of Federal income tax expense of approximately $14.6 million. Additionally, the annual amortization of the deficient ADIT for the fully projected future test year of approximately $2.13 million is included to arrive at total tax expense (Exhibit JH-1, Attachment B, Page 2, Column 2 through 7, Lines 1 through Lines 15 and discussion below) resulting in an increase in total Federal income tax expense of $16.7 million.

The ADIT included in rate base which represent future deductible or taxable statutory book/tax temporary differences are required to be remeasured at the new Federal income tax rate as of the ending balance sheet date prior to the enactment of the new Federal income tax rate. The Company established a Regulatory Liability for the excess ADIT related to the TCJA decrease of the

Federal income tax rate from 35% to 21% effective January 1, 2018 that continues to be passed back to customers (10-years for non-property, 42-years for Federal NOL and ARAM for property). As mentioned above, for illustrative purposes, the Company used an effective date of January 1, 2022 of the increase in the Federal income tax rate which requires ADIT to be remeasured at 28% based on the 2021 ending balance sheet. The Company remeasured the statutory temporary difference for the future test year ended November 30, 2020 on Attachment B, Page 2, Column 2 through 7, Lines 1 through Lines 15 by dividing the deferred tax balance at the current income tax rates to compute the gross balances, then tax effecting the gross balances at the new Federal income tax rate resulting in deficient ADIT of approximately $91.5 million. The Company has presented the amount as a Regulatory Asset that is included in rate base on Attachment B, Page 1, Lines 11-14 to illustrate that the remeasurement of ADIT does not have an immediate impact on rate base as of the balance sheet remeasurement date. Consistent with amortization periods agreed to under the TCJA Federal rate change in 2017, the Company has applied the same amortization periods (10-years for non-property, 42-years for Federal NOL and ARAM for property which is estimated at 39.2-years based on the book depreciation composite rate). The estimated annual amortization of the deficient ADIT is approximately $2.1 million (See Attachment B, Page 2, Lines 2 through 15 for the illustrative computation of the annual amortization based on the FTY remeasurement date and Attachment A, Page 1, Line 23, Column 6 for the amount of the estimated annual amortization included in the computation of the FPFTY Federal income tax expense. This annual amortization of the deficient ADIT is included in total Federal tax expense in the cost of service on Attachment A, Page 1, Line 23. The increase in ADIT for the fully projected future test year is approximately $7.1 million. The Company multiplied the increase by the % Rate of Return computed for the fully projected future test year of 7.88% resulting in decrease in the revenue requirement of approximately ($557k).

The Company notes that the illustrative impact of increased tax expense of $16.7 million and ADIT of ($557k) is approximately $16.2 million, net. The Company applied the statutory tax rate gross up factor of 1.4774 (See computation on Exhibit JH-1, Attachment A, Page 1, Lines 49 through 56) resulting in a gross revenue requirement of approximately $23.9 million. To determine the percentage adjustment to apply prospectively to customer bills, the Company divided the gross revenue requirement of $23.7 million by the fully projected future test year revenue of $758 million at proposed rates to arrive at positive percentage adjustment of 3.15% to prospectively implement the illustrative impact of a new Federal income tax rate. The Company notes that the illustrative schedules and computation of the positive percentage adjustment is subject to the Commission approval of the final revenue requirement for the fully project future test year ended December 31, 2022.

Q. Does this conclude your testimony?

A. Yes.

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
CURRENT FEDERAL TAX EXPENSE
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 /
FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No	Description	Ref	Federal Tax Expense at 21% Pro Forma At Forecasted HTY Present Base Rates	Federal Tax Expense at 21% Pro Forma At Forecasted FTY Proposed Base Rates	Federal Tax Expense at 21% Pro Forma At Forecasted FPFTY Proposed Base Rates	/ 1 Federal Tax Expense at 28% Pro Forma At Forecasted FPFTY Proposed Base Rates	Change in Federal Tax Pro Forma At Forecasted FPFTY Proposed Base Rates	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	Total Sales and Transportation Revenue	Exh 102, Sch 3, Pg 3, Ln 9	646,700,377	655,424,612	758,023,283	758,023,283	-	
2	Late Payment Fees	Exh 102, Sch 3, Pg 3, Ln 10	1,237,138	1,253,827	1,450,098	1,450,098	-	
3	Other Operating Revenues (Excl. Transportation)	Exh 102, Sch 3, Pg 3, Ln 11	11,582	11,582	11,582	11,582	-	
4	Total Operating Revenue Deductions	Exh 102, Sch 3, Pg 3, Ln 9	434,272,263	476,823,840	500,882,916	500,882,916	-	
5	Operating Income Before Income Taxes	Exh 102, Sch 3, Pg 3, Ln 9	213,676,833	179,866,180	258,602,047	258,602,047	-	
6	Statutory Permanent Adjustments	Exh 107, Pg 16, Ln 15	(32,258,807)	(39,140,025)	(43,142,698)	(43,142,698)	-	
7	Statutory Temporary (Deferred) Adjustments	Exh 107, Pg 16, Ln 29	(56,620,879)	(62,103,254)	(87,369,535)	(87,369,535)	-	
8	Pennsylvania Bonus Depreciation Adj	Exh 106, Pg 17, Ln 4	(26,402,313)	(12,707,746)	(11,100,575)	(11,100,575)	-	
9	State Taxable Income (Before NOL)	= Sum Ln 5,6,7,8	98,394,835	65,915,156	116,989,239	116,989,239	-	
10	Net Operating Loss Deduction	= Ln 9 * 40%	39,357,934	26,366,062	46,795,696	46,795,696	-	
11	State Taxable Income (After NOL)	= Ln 9 - Ln 10	59,036,901	39,549,094	70,193,543	70,193,543	-	
12	State Tax Rate		9.99%	9.99%	9.99%	9.99%	0.00%	
13	State Income Tax Payable	= Ln 11 * Ln 12	5,897,786	3,950,954	7,012,335	7,012,335	-	
14								
15	Federal Taxable Income	= Sum Ln 5,6,7 Less Ln 13	118,899,361	74,671,947	121,077,479	121,077,479	-	
16	Federal Tax Rate		21%	21%	21%	28%	7.00%	
17	Current Federal Tax	= Ln 15 * Ln 16	24,968,866	15,681,109	25,426,271	33,901,694	8,475,424	
18	Deferred Federal Tax	= (Ln 7) * Ln 16	11,890,385	13,041,683	18,347,602	24,463,470	6,115,867	
19	Federal Benefit of State Deferred Taxes	Exh 107, Pg 16, Ln 35	(21,747)	(9,501)	(18,334)	(24,445)	(6,111)	
20	Federal Investment Tax Credit	Exh 107, Pg 8, Ln 23	(287,111)	(259,687)	(243,013)	(243,013)	-	
21	Total Current and Deferred Federal Tax Expense		36,550,392	28,453,604	43,512,526	58,097,706	14,585,180	
22	TCJA Excess Amortization	Exh 107, Pg 16, Ln 34	(3,461,677)	(2,467,702)	(2,643,471)	(2,643,471)	-	/ 2
23	FTRA Deficient Amortization	Att B, Pg 2, Cl 9, Ln 28				2,132,389	2,132,389	/ 3
24	Total Current and Deferred State Tax Expense		6,001,345	3,996,198	7,099,641	7,099,641	-	
25	Total Tax Expense		39,090,061	29,982,100	47,968,696	64,686,265	16,717,569	
26								
27								
28	**Rate Base**							
29	Property Plant and Equipment	Exh 108, Pg 3, Ln 6	2,451,787,100	2,716,574,439	3,058,869,624	3,058,869,624	-	
30	Working Capital	Exh 108, Pg 3, Ln 6	36,919,306	41,724,172	39,774,628	39,774,628	-	
31	Deferred Income Taxes	Att B, Pg 1, Ln 16	(395,942,233)	(410,075,527)	(422,195,373)	(429,266,067)	(7,070,694)	
32	Customer Deposits	Exh 108, Pg 3, Ln 6	(3,454,041)	(3,457,993)	(3,456,339)	(3,456,339)	-	
33	Customer Advances for Construction	Exh 108, Pg 3, Ln 6	3,034	19,525	19,525	19,525	-	
34	Total Rate Base	Exh 108, Pg 3, Ln 6	2,089,313,166	2,344,784,616	2,673,012,065	2,665,941,371	(7,070,694)	
35	% Rate of Return Earned on Rate Base	Exh 102, Sch 3, Ln 28	8.36%	6.39%	7.88%	7.88%	7.88%	/ 4
36	Revenue Requirement	= Ln 34 * Ln 35	174,586,773	149,884,080	210,633,351	210,076,180	(557,171)	
37								
38	**Illustrative Impact of Increased Tax Expense and ADIT, net**	**= Sum Ln 25, Ln 36**					**16,160,398**	
39								
40	Statutory Tax Rate Gross-Up Factor	= Ln 37					1.47744707	/ 5
41								
42	**Gross Revenue Requirement**	**= Ln 38 * Ln 40**					**23,876,133**	
43								
44	Total Sales and Transportation Revenue adjusted	= Ln 1					758,023,283	/ 6
45								
46	**Base Distribution Percent Increase Per Bill**	**= Ln 42 / Ln 44**					**3.150%**	
47								
48								
49	**Computation of Statutory Tax Rate Gross-Up Factor**							
50	Federal Rate						28.00%	
51	State Rate						9.99%	
52	State Rate after State NOL (40% Limitation)						5.99%	
53	Federal Benefit of State Rate						-1.68%	
54	Total Statutory Rate						32.32%	
55								
56	Statutory Tax Rate Gross-Up Factor						1.47744707	

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for FPFTY 2022

/ 2 - Illustrative schedule prepared reflects no change in the pass back of Excess ADIT related to TCJA of 2017. The permanent benefit will continue to be passed back to customers over the respective amortization periods.
However, the 254 Regulatory Liability balance and 190 Deferred Tax (Gross-Up) will be remeasured based on the new Statutory Tax Rate Gross-Up Factor due to the new Federal tax rate. The entry would result in net zero deferred tax expense
DR 254 Regulatory Liability and CR 411 Deferred Tax Benefit / CR 190 Deferred Tax (Gross-Up) and DR 410 Deferred Tax Expense

/ 3 - Illustrative schedule prepared FPFTY Deficient ADIT annual amortization consistent with the amortization periods agreed to for Excess ADIT from TCJA decrease in Federal tax rate (See Attachment B, Page 2, Column 9, Lines 15-28 for computation)

/ 4 - Illustrative schedule prepared applies 7.88% rate of return which represents the rate of return fro the 2021 Rate Case FPFTY at Proposed Rates. The Company would update based on the final rate of return approved by the commission.

/ 5 - Illustrative schedule prepared applies a statutory tax rate gross-up factor based on the new Federal income tax rate (See computation on rows 49-54)

/ 6 - Illustrative schedule prepared applies the total sales and transportation revenue which represent revenue for the 2021 Rate Case FPFTY at Proposed Rates. The Company would updated based on the final revenue approved by the commission.

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 / FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No	Description	Ref	ADIT at 21% Pro Forma At Forecasted HTY Present Base Rates	ADIT at 21% Pro Forma At Forecasted FTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FTY Proposed Base Rates	Change in ADIT Pro Forma At Forecasted FTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FPFTY Proposed Base Rates
	(1)	(2)	(3)	(4)	(5)	(6) = (5 - 4)	(8)
					/ 1		
1	Accumulated Deferred Income Taxes (ADIT)						
2	Account 190 - Deferred Income Taxes	Att C, Pg 1, Ln 9	46,585,707	46,597,345	60,622,600	14,025,255	58,089,507
3	Account 282 - Deferred Income Taxes-Depreciation	Att C, Pg 1, Ln 12	(298,978,832)	(315,591,465)	(420,788,620)	(105,197,155)	(438,168,881)
4	Total ADIT		(252,393,125)	(268,994,120)	(360,166,021)	(91,171,900)	(380,079,375)
5					/ 2		/ 5
6	Excess ADIT (TCJA)						
7	Account 190 - Deferred Income Taxes	Att C, Pg 1, Ln 18	27,899,349	26,700,994	26,700,994	-	25,402,776
8	Account 282 - Deferred Income Taxes-Depreciation	Att C, Pg 1, Ln 19	(171,448,457)	(167,782,401)	(167,782,401)	-	(163,628,980)
9	Total Excess ADIT		(143,549,108)	(141,081,407)	(141,081,407)	-	(138,226,203)
10					/ 3		
11	Deficient ADIT (FTRA)	/ 7					
12	Account 190 - Deferred Income Taxes				(14,025,255)	(14,025,255)	(13,474,043)
13	Account 282 - Deferred Income Taxes-Depreciation				105,197,155	105,197,155	102,513,554
14	Total Deficient ADIT				91,171,900	91,171,900	89,039,511
15							/ 6
16	Total ADIT & (Excess)/Deficient ADIT	Att C, Pg 1, Ln 21	(395,942,232)	(410,075,527)	(410,075,527)	-	(429,266,067)
					/ 4		

NOTES
/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for FPFTY 2022 resulting in remeasurement of ADIT at the new Federal tax rate as of the end of FTY balance sheet date
/ 2 - Illustrative schedule prepared reflects FTY ADIT remeasured at new Federal tax rate (See Attachment B, Page 2, Lines 15-28 for computation of the remeasurement)
/ 3 - Illustrative schedule prepared reflects no change in the pass back of Excess ADIT related to TCJA of 2017. The permanent benefit will continue to be passed back to customers over the respective amortization periods
/ 4 - Illustrative schedule prepared reflects no change in total ADIT & (Excess) / Deficient ADIT as of the balance sheet date when deferred taxes are remeasured at the new Federal tax rate as the permanent difference is recorded as a Regulatory Asset to be amortized over respective periods
/ 5 - Illustrative schedule prepared reflects FPFTY ADIT remeasured at new Federal tax rate (See Attachment B, Page 2, Lines 38-51 for computation of the remeasurement)
/ 6 - Illustrative schedule prepared reflects decrease in Deficient ADIT from FTY to FPFTY based on estimated annual amortization (See Attachment B, Page 2, Column 9, Lines 15-28)
/ 7 - Illustrative schedule prepared reflects FTY and FPFTY Deficient ADIT as a balance separate from Excess ADIT attributed to TCJA of 2017 for illustrative purposes only (actual accounting may be presented as a net balance)

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 / FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No	Description	Ref	ADIT at 21% Pro Forma At Forecasted FTY Proposed Base Rates	Current Tax Rates Pro Forma At Forecasted FTY Proposed Base Rates	Gross ADIT Pro Forma At Forecasted FTY Proposed Base Rates	Illustrative Tax Rates Pro Forma At Forecasted FTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FTY Proposed Base Rates	/ 1 (Excess)/Deficient ADIT Pro Forma At Forecasted FTY Proposed Base Rates	/ 2 Amortizable Period Pro Forma At Forecasted FTY Proposed Base Rates	(Excess)/Deficient ADIT Amort Pro Forma At Forecasted FTY Proposed Base Rates
		(1)	(2)	(3)	(4) = (2 / 3)	(5)	(6) = (4 X 5)	(7) = (2 - 6)	(8)	(9) = (7 / 8)
1	Account 190 - Deferred Income Taxes									
2	LIFO Inventory Adj - Federal	Att C, Pg 1, Ln 2	6,973,737	18.90%	36,893,980	25.20%	9,298,316	(2,324,579)	10.00	(232,458)
3	LIFO Inventory Adj - State	Att C, Pg 1, Ln 3	3,685,709	9.99%	36,893,984	9.99%	3,685,709	0	10.00	-
4	Capitalized Inventory - Fed	Att C, Pg 1, Ln 4	1,015,878	18.90%	5,374,419	25.20%	1,354,504	(338,626)	10.00	(33,863)
5	Capitalized Inventory - St	Att C, Pg 1, Ln 5	536,904	9.99%	5,374,414	9.99%	536,904	0	10.00	-
6	Cust. Advances - Fed	Att C, Pg 1, Ln 6	565,678	18.90%	2,992,673	25.20%	754,237	(188,559)	10.00	(18,856)
7	Cust. Advances - St	Att C, Pg 1, Ln 7	298,968	9.99%	2,992,673	9.99%	298,968	0	10.00	-
8	Federal Net Operating Loss	Att C, Pg 1, Ln 8	33,520,471	21.00%	159,621,290	28.00%	44,693,961	(11,173,490)	42.00	(266,035)
9	Total Account 190	Att C, Pg 1, Ln 9	46,597,345		250,143,433		60,622,600	(14,025,255)		(551,212)
10										
11	Account 282 - Deferred Income Taxes-Depreciation									
12	Excess Accelerated Tax Depreciation - Fed	Att C, Pg 1, Ln 11	(315,591,465)	21.00%	(1,502,816,501)	28.00%	(420,788,620)	105,197,155	39.20	2,683,601
13	Total Account 282	Att C, Pg 1, Ln 12	(315,591,465)		(1,502,816,501)		(420,788,620)	105,197,155		2,683,601
14										
15	Total ADIT		(268,994,120)		(1,252,673,068)		(360,166,021)	91,171,900		2,132,389
16										
17										

Line No	Description	Ref	ADIT at 21% Pro Forma At Forecasted FPFTY Proposed Base Rates	Current Tax Rates Pro Forma At Forecasted FPFTY Proposed Base Rates	Gross ADIT Pro Forma At Forecasted FPFTY Proposed Base Rates	Illustrative Tax Rates Pro Forma At Forecasted FPFTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FPFTY Proposed Base Rates
18-22							
23		(1)	(2)	(3)	(4) = (2 / 3)	(5)	(6) = (4 X 5)
24	Account 190 - Deferred Income Taxes						
25	LIFO Inventory Adj - Federal	Att C, Pg 1, Ln 2	6,973,737	18.90%	36,893,980	25.20%	9,298,316
26	LIFO Inventory Adj - State	Att C, Pg 1, Ln 3	3,685,709	9.99%	36,893,984	9.99%	3,685,709
27	Capitalized Inventory - Fed	Att C, Pg 1, Ln 4	1,015,878	18.90%	5,374,419	25.20%	1,354,504
28	Capitalized Inventory - St	Att C, Pg 1, Ln 5	536,904	9.99%	5,374,414	9.99%	536,904
29	Cust. Advances - Fed	Att C, Pg 1, Ln 6	327,660	18.90%	1,733,458	25.20%	436,880
30	Cust. Advances - St	Att C, Pg 1, Ln 7	138,835	9.99%	1,389,740	9.99%	138,835
31	Federal Net Operating Loss	Att C, Pg 1, Ln 8	31,978,769	21.00%	152,279,852	28.00%	42,638,359
32	Total Account 190	Att C, Pg 1, Ln 9	44,657,492		239,939,847		58,089,507
33							
34	Account 282 - Deferred Income Taxes-Depreciation						
35	Excess Accelerated Tax Depreciation - Fed	Att C, Pg 1, Ln 11	(328,626,661)	21.00%	(1,564,888,862)	28.00%	(438,168,881)
36	Total Account 282	Att C, Pg 1, Ln 12	(328,626,661)		(1,564,888,862)		(438,168,881)
37							
38	Total ADIT		(283,969,169)		(1,324,949,015)		(380,079,375)
39							
40							

Line No	Statutory Tax Rates	Current Tax Rates	Illustrative Tax Rates
41			
42	Federal Rate	21.000%	28.000%
43	State Rate	9.990%	9.990%
44	Federal Benefit of State Rate	-2.098%	-2.797%
45	Federal Rate, net of State Benefit	18.902%	25.203%
46	Total Statutory Rate	28.892%	35.193%

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for FPFTY 2022 resulting in remeasurement of ADIT at the new Federal tax rate as of the end of FTY balance sheet date

/ 2 - Illustrative schedule prepared FPFTY Deficient ADIT estimated annual amortization consistent with the amortization periods agreed to for Excess ADIT from TCJA decrease in Federal tax rate (See Attachment B, Page 2, Column 9, Lines 15-28 for computation)

Non-Property - 10-yr
Federal NOL - 42-yr
Property - ARAM (Illustrative example reflects 39.20 yr which represents the FTY book depre composite rate - Actuals will be based on ARAM computed in PowerTax)

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
RATE BASE ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 /
FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No.	Acct		Pro Forma Balance 11/30/20 (1)	Pro Forma Balance 11/30/2021 (2)	Pro Forma Balance 12/31/2022 (3)
1		Account 190 - Deferred Income Taxes			
2	19001000	LIFO Inventory Adj - Federal	6,130,528	6,973,737	6,973,737
3	19002000	LIFO Inventory Adj - State	3,240,062	3,685,709	3,685,709
4	19001000	Capitalized Inventory - Fed	960,030	1,015,878	1,015,878
5	19002000	Capitalized Inventory - St	507,388	536,904	536,904
6	19005000	Cust. Advances - Fed	726,546	565,678	327,660
7	19006000	Cust. Advances - St	383,989	298,968	138,835
8	19005000	Federal Net Operating Loss	34,637,164	33,520,471	31,978,769
9		Total Account 190	46,585,707	46,597,345	44,657,492
10		Account 282 - Deferred Income Taxes-Depreciation			
11	28205000	Excess Accelerated Tax Depreciation - Fed	(298,978,832)	(315,591,465)	(328,626,661)
12		Total Account 282	(298,978,832)	(315,591,465)	(328,626,661)
13		Account 283 - Deferred Income Taxes - Other			
14	28305000	Legal Liability-Lease on G.O. Bldg. - Fed	0	0	0
15	28306000	Legal Liability-Lease on G.O. Bldg. - St	0	0	0
16		Total Account 283	0	0	0
17		Account 254 - Regulatory Liability (Before Gross-up)			
18	25401000 / 25405000	Deficient Deferred Taxes 190- NOL, Inventory & Customer Advances	27,899,349	26,700,994	25,402,776
19	25401000 / 25405000	Excess Accelerated Tax Depreciation - Fed	(171,448,457)	(167,782,401)	(163,628,980)
20		Total Account 254	(143,549,108)	(141,081,407)	(138,226,203)
21		Total Accumulated Deferred Income Taxes (ADIT) and Excess ADIT	(395,942,232)	(410,075,527)	(422,195,373)

Note /1 Attachment C breaks out ADIT from Excess ADIT presented in total ADIT in Exhibit 108, Schedule 8 balances

COLUMBIA STATEMENT NO. 10-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

REBUTTAL TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

Q. Please state your name and business address.

A. My name is Jennifer Harding. 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 Director, Income Tax Operations at NCSC.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding by Bureau of Investigation and Enforcement ("I&E") Witness Zalesky and Office of the Consumer Advocate ("OCA") Witnesses Effron and Mierzwa

Q. What issues will you be addressing in your rebuttal testimony?

A. I will address the Company's proposed Federal Tax Reform Adjustment Rider ("FTRA") raised by multiple parties in this proceeding. Additionally, I will also address the Accumulated Deferred Income Tax ("ADIT") adjustment proposed by OCA Witness Effron that corresponds with his proposed Plant in Service adjustment. Finally, I will address the correction the ADIT in rate base as included in OCA Witness Effron's direct testimony.

Q. Please summarize I&E Witness Zalesky and OCA Witness Mierzwa's opposition to the Company's proposed FTRA Rider.

A. I&E Witness Zalesky recommended that the Company's proposed FTRA Rider be disallowed on the basis that the Company cannot say with any certainty if/when an increase to the federal corporate income tax rate will take effect. Mr. Zalesky also contends that the Commission's experience dealing with the Tax Cuts and Jobs Act ("TCJA") will result in adequate and timely guidance on a statewide basis following a change in federal corporate income tax rates, and that the Company's should be required to await such guidance. Additionally, I&E Witness Zalesky argued that the FTRA Rider should not allow rate adjustments via the proposed surcharge mechanism for impacts associated with deferred federal income taxes, indicating that the proposed FTRA Rider should only be allowed for the *current* Federal income tax expense portion of the change.

OCA Witness Mierzwa also recommended that the Company's proposed FTRA Rider should not be approved on the basis that it is uncertain when the next change in the corporate tax rate will occur and such change should be addressed by the Commission on a generic basis for all public utilities.

Q. Do you agree with I&E Witness Zalesky and OCA Witness Mierzwa basis for opposition of the FTRA Rider?

A. No I do not. In fact, I believe the basis for their recommendations support the purpose of the Company's proposed FTRA Rider. I fully agree that no one can say with any certainty if/when an increase to the federal corporate income tax rate will take effect and I indicated in my testimony that it is completely outside of the Company's control. A change in the Federal income tax rate will impact all utilities at the same time and such change may impact whether a utilities' existing rates are no longer "just and reasonable," as required by Pennsylvania law. The circumstances of each utility must be taken into consideration in individual cases by the Commission. The purpose of the FTRA Rider is to function as a temporary mechanism if/when an increase or decrease in Federal income tax rates result in existing rates being no longer "just and reasonable".

Q. Do you agree with I&E Witness Zalesky and OCA Witness Mierzwa argument that the Company should wait for statewide guidance from the Commission?

A. No, I do not. I agree that the Commission and its advisory staff have recently dealt with the complexity of tax reform and reduction of the Federal income tax rate with respect to the TCJA. However, due to the complexity of the tax law changes as a result of TCJA and the numerous public utilities involved, the Commission was unable to act in a prompt manner to respond to the TCJA changes. The changes in federal tax rate under the TCJA became effective for calendar year tax payers on January 1, 2018. On February 12, 2018, the Commission issued a secretarial letter with common data requests to fixed utilities. In the letter, the Commission had stated that it was unable to determine when it would complete its review of data and comments submitted in response the secretarial letter in response to TCJA, and resolve the issues presented. Subsequently, the Commission issued a temporary rates order (Docket No. M-2018-2641242) on March 15, 2018, which established the current, Commission-approved rates and riders of most large public utilities as temporary rates for an initial period of six months. It ordered each affected public utility to file a tariff supplement designating its existing rates and riders as temporary rates. It was not until approximately May 17, 2018, over five months after new federal tax rates had become effective, that the Commission issued orders directing various utilities to adjust their rates to reflect lower temporary rates. Various utilities that had base rate cases on file with the Commission were not directed to immediately file lower temporary rates.

The Company believes that the FTRA Rider would provide a more prompt, temporary mechanism to ensure effective base rates would be "just and reasonable", as required by Pennsylvania law, and would alleviate administrative burden for the Commission and its advisory staff due to the fact that a future increase or decrease in the Federal income tax rate would impact all public utilities and require the Commission's review. Additionally, the Company believes that the proposed FTRA mechanism functions very similarly to the State Tax Adjustment that was enacted by the Commission in 1970 for changes in Pennsylvania state income tax rate (and other non-income tax rates) which would increase or decrease existing customer rates.

Q. Please explain the similarities of the proposed FTRA and the State Tax Adjustment ("STAS") pursuant to 52 Pa. Code § 69.51 - § 69.

A. The STAS provides for the automatic adjustment of rates for changes in state taxes, including the Pennsylvania Corporate Net Income Tax, Capital Stock Tax, Gross Receipts Tax and Public Utility Realty Tax. Pursuant to Section 69.52 a utility which has a State tax adjustment surcharge or gross receipts tax rider shall maintain its surcharge and rider rates at 0% unless there has been a change in the applicable tax rates. Procedurally under Section 69.52 Exhibit A, every public utility which has been subjected to new or increased taxes enacted by the General Assembly shall compute the surcharge as prescribed by the Commission and submit the computation to the Commission.

Furthermore, pursuant to Section 69.55(2), the State tax adjustment surcharge and gross receipts tax rider shall be zeroed, and the tax expenses recovered through application of the surcharge and rider shall be rolled into base rates by filing a tariff or tariff supplement and supporting data on 60-days' statutory notice to the Commission. The transfer of revenues to base rates shall be accomplished so that there will be no effective change in total revenues recovered from each service classification as a result of the roll-in. It is my understanding that many utilities implement this roll-in through the filing of a new base rate case.

Q. Will the Company's proposed FTRA Rider be set at zero until a future increase or decrease in the Federal income tax rate?

A. Yes, the Company's proposed FTRA Rider will be set at zero until a future increase or decrease in the Federal income tax rate is in effect. As mentioned above, the Company does not know if/when a future change in the Federal income tax rate would be in effect, but the FTRA Rider would function as a temporary mechanism to adjust existing rates that are no longer "just and reasonable," as required by Pennsylvania law.

Q. At the time of a future increase or decrease in the Federal income tax rate, will the Company submit the FTRA Rider and schedules to support the impact on the change in the most recently approved base rates?

A. Yes, as mentioned above, the FTRA will be set at zero. At such time that a future change in the Federal income tax rate is in effect, the Company will submit the FTRA Rider and schedules supporting the change in effective base rates due to the change in Federal income tax expense based on a future increase or decrease in the Federal income tax rate for the Commission's approval. The FTRA would function as a temporary mechanism between the time when a future increase or decrease in the Federal income tax rate is in effect and when the Company's would file its next rate case after a future change in the Federal income tax rate.

Q. How would the Company account for the impact to accumulated deferred income taxes ("ADIT") as a result of a future increase or decrease of the Federal income tax rate?

A. I acknowledge that no one can say with any certainty if/when an increase to the federal corporate income tax rate will take effect and indicated in my testimony that it is completely outside of the Company's control. However, a change in the Federal income tax rate impacts Federal income tax expense and also requires the re-measurement of ADIT as of the balance sheet date preceding the effective date of a future change in Federal income tax rate. The re-measurement results in Excess ADIT (EDIT) or Deficient ADIT (DDIT) due to a decrease or increase in the Federal income tax rate, respectively. The EDIT or DDIT is not recognized as a one-time charge to Federal tax expense, but is amortized over a period agreed to by the Commission. The amortization of EDIT or DDIT is recognized as a flow-through adjustment to *current* Federal income tax expense. The Company expects to request approval for regulatory accounting to establish a deferral or reserve as a result of EDIT or DDIT from a future change in the Federal income tax rate. The illustrative schedules included in Exhibit JH-1 attached to my direct testimony, depict the illustrative impact to effective customer rates from a future change in the Federal income tax rate. However, the total impact would be subject to facts and circumstances, including timing, at the time of a change in the Federal income tax rate, supported by schedules and submitted to the Commission for approval.

Q. Do you agree with I&E Witness Zalesky's comment that the FTRA Rider should only be allowed for the *current* Federal income tax expense portion of the change?

A. In part. As mentioned above, a change in the Federal income tax rate impacts Federal income tax expense and also requires the re-measurement of ADIT as of the balance sheet date preceding the effective date of a future change in Federal income tax rate. The re-measurement results in Excess ADIT (EDIT) or Deficient ADIT (DDIT) due to a decrease or increase in the Federal income tax rate, respectively. The EDIT or DDIT is not recognized as a one-time charge to Federal tax expense, but is amortized over a period agreed to by the Commission. Any such amortization is best handled in the context of a base-rate proceeding, as was done with the TCJA. However, as was the case with the TCJA, a change to the income tax rate would affect the ongoing allowance for deferred income taxes. The FTRA would reflect that change to prospective deferred income tax expense, as was done with the TCJA.

Q. Do you agree with OCA Witness Effron's adjustment of ADIT in relation to the proposed Plant in Service adjustment?

A. No, I do not. As indicated in Columbia Witness Schultz's rebuttal testimony, the Company disputes the Plant in Service adjustments proposed by OCA Witness Effron. Additionally, OCA Witness Effron assumed a change in ADIT is proportional to the plant adjustment. However, the Company believes this high level approach understates the correlating adjustment, or reduction, to ADIT by approximately $1.1 million. The basic flaw of Mr. Effron's high level calculation is that it assumes all of the disallowed plant is subject to accelerated depreciation. Also, it assumes that accelerated depreciation under the Modified Accelerated Cost Recovery System ("MACRS") method of depreciation is at the average rate of the ADIT balance. However, the early years of accelerated depreciation are at a higher than average rate, and thus a disallowance of new plant additions results in a greater reduction to the ADIT balance. The Company notes that tax deductions are normalized, resulting in current deduction offset by a future taxable temporary difference creating a deferred tax liability and net zero tax expense. The proposed reduction of plant in service results in the reversal of the current deduction, and reversal of the offsetting future taxable temporary difference. Any adjustment, or reduction in ADIT, associated with a change to the plant claimed by the Company should represent the adjusted book/tax difference tax effected at the Federal income tax rate of 21%. To the extent that Plant in Service is adjusted, the Company has prepared a computation to determine the correlating ADIT adjustment on Exhibit JH-1R, pages 1 and 2.

Q. Do you agree with OCA Witness Effron's ADIT correction to rate base?

A. Yes I do. I have attached Exhibit JH-2R that summarizes the adjustments for Customer Advances for Construction NonCurrent of $34,337 and excess ADIT of $1,060,441 resulting in a decrease in ADIT in total of $1,094,779. Due to an inadvertent formula error, Customer Advances for Construction NonCurrent was presented as $138,835 compared to the corrected amount of $173,172 resulting in the FPFTY balance being understated by $34,337. As well, excess ADIT balance for the twelve months ended November 30, 2020 inadvertently included an adjustment of ($1,060,441) on Exhibit 108, Schedule 8 due to a formula error resulting in the HTY balance, FTY balance and FPFTY balance on Attachment A, Page 1, Line 28 to be overstated by ($1,060,441). The differences above result in a decrease in accumulated deferred income taxes resulting in an increase to rate base of $1,094,779. The adjustments were updated on Exhibit 108, Schedule 8 which is included in Columbia Witness Schultz's rebuttal testimony as Exhibit NMS-2 and referenced in Columbia Witness Miller's rebuttal testimony.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
PLANT ADDITIONS
COMPUTATION OF ADIT ADUSTMENT
($000)

Line No.	Description	Ref	2021	2022	Total
			(1)	(2)	(3)
	Computation by OCA				
1	Average Plant Additions 2019 - 2020	OCA Sch B-1	$ 286,203	$ 286,203	$ 572,406
2	Plant Additions, per Company	OCA Sch B-1	335,340	324,536	659,876
3	Adjustment to Plant in Service	OCA Sch B-1	(49,137)	(38,333)	(87,470)
4	Adjustment to Depreciation Reserve	OCA Sch C-2	(1,228)	(958)	(2,187)
5	Adjustment to ADIT	OCA Sch B-1	(1,897)	(1,087)	(2,984)
6	Net Rate Base Adjustment		(46,012)	(36,288)	$ (82,299)
	Computation of ADIT by Columbia				
7	Reduction in Plant in Service	= Line 3	$ (49,137)	$ (38,333)	$ (87,470)
8	Bonus Depre	= Line 28	-	-	-
9	Plant in Service Basis after Bonus		(49,137)	(38,333)	(87,470)
10	Repairs Deduction	= Line 27	(8,064)	(7,679)	(15,742)
11	Plant in Service Basis after Repairs		(41,073)	(30,654)	(71,728)
12	MSC Deduction	= Line 29	(191)	(134)	(325)
13	Plant in Service Basis after MSC		(40,882)	(30,520)	(71,403)
14	MACRS Depreciation (20yr) - 1st Year	3.75%	(1,533)	(1,145)	(2,678)
15	Plant in Service Basis after MSC		(39,349)	(29,376)	(68,725)
16	MACRS Depreciation (20yr) - 2nd Year	7.22%	(2,841)		(2,841)
17	Remaining Plant in Service Basis		(36,509)	(29,376)	(65,885)
18	Total Tax Deduction	= Sum Lines 8, 10, 12, 14, 16	(12,628)	(8,957)	(21,585)
19	Total Book Depreciation Addback	= Line 4	1,228	958	2,187
20	Net Book/Tax Difference	= Sum Line 18 and 19	(11,400)	(7,999)	(19,399)
21	Federal Tax Rate		21.00%	21.00%	21.00%
22	Reduction in ADIT	= Line 21 * Line 22	$ (2,394)	$ (1,680)	$ (4,074)
23	Difference between OCA Proposed Adjustment and the Company				(1,090)
	Computation of Repairs and MCS % by Columbia				
24	Repairs on Gas Pipeline	Exhibit 107, Page 16, Line 18	(55,032)	(65,009)	
25	Bonus Depreciation	Exhibit 107, Page 16, Line 19	-	-	
26	Sec 263A Mixed Service Costs	Exhibit 107, Page 16, Line 20	(1,559)	(1,417)	
27	Repairs on Gas Pipeline	= Line 24 / Line 2	16.41%	20.03%	
28	Bonus Depreciation	= Line 25 / Line 2	0.00%	0.00%	
29	Sec 263A Mixed Service Costs	= Line 26 / Line 2	0.46%	0.44%	

COLUMBIA GAS OF PENNSYLVANIA, INC.
PLANT ADDITIONS
TAX DEPRECIATION MACRS TABLE
($000)

Table A-1 3-, 5-, 7-, 10-, 15-, and 20-year Property Half Year Convention

Line No.	Year	(1)	(2)	(3)	(4)	(5)	(6)
		Depreciation rate for recovery period					
		3-year	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**
1	1	33.33%	20.00%	14.29%	10.00%	5.00%	3.750%
2	2	44.45%	32.00%	24.49%	18.00%	9.50%	7.219%
3	3	14.81%	19.20%	17.49%	14.40%	8.55%	6.677%
4	4	7.41%	11.52%	12.49%	11.52%	7.70%	6.177%
5	5		11.52%	8.93%	9.22%	6.93%	5.713%
6	6		5.76%	8.92%	7.37%	6.23%	5.285%
7	7			8.93%	6.55%	5.90%	4.888%
8	8			4.46%	6.55%	5.90%	4.522%
9	9				6.56%	5.91%	4.462%
10	10				6.55%	5.90%	4.461%
11	11				3.28%	5.91%	4.462%
12	12					5.90%	4.461%
13	13					5.91%	4.462%
14	14					5.90%	4.461%
15	15					5.91%	4.462%
16	16					2.95%	4.461%
17	17						4.462%
18	18						4.461%
19	19						4.462%
20	20						4.461%
21	21						2.231%
22		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Original: OCA 1-008
J. Harding
Attachment A
Page 5 of 5

COLUMBIA GAS OF PENNSYLVANIA, INC
DEFERRED INCOME TAXES
BALANCE ENDING
December 31, 2022

Line No.	Acct		Reference	As Submitted (3) Pro Forma FPFTY Balance 12/31/2022		As Corrected (3) Pro Forma FPFTY Balance 12/31/2022	Impact to Rate Base (3) Pro Forma FPFTY Balance 12/31/2022
1		Account 190 - Deferred Income Taxes					
2	19001000	LIFO Inventory Adj - Federal	OCA 1-008, Attachment A, Page 2	6,973,737		6,973,737	0
3	19002000	LIFO Inventory Adj - State	OCA 1-008, Attachment A, Page 2	3,685,709		3,685,709	0
4	19001000	Capitalized Inventory - Fed	OCA 1-008, Attachment A, Page 2	1,015,878		1,015,878	0
5	19002000	Capitalized Inventory - St	OCA 1-008, Attachment A, Page 2	536,904		536,904	0
6	19005000	Cust. Advances - Fed	OCA 1-008, Attachment A, Page 2	327,660		327,660	0
7	19006000	Cust. Advances - St	OCA 1-008, Attachment A, Page 2	138,835	/ 1	173,172	34,337
8	19005000	Federal Net Operating Loss	OCA 1-008, Attachment A, Page 3	31,978,769		31,978,769	0
9	19005000	Deficient Deferred Taxes 190- NOL, Inventory & Customer Advances	OCA 1-008, Attachment A, Page 4	25,402,776		25,402,776	0
10		Total Account 190		70,060,268		70,094,606	34,337
11		Account 282 - Deferred Income Taxes-Depreciation					
12	Various	Excess Accelerated Tax Depreciation - Fed	See Below	(492,255,641)		(491,195,199)	1,060,442
13		Total Account 282		(492,255,641)		(491,195,199)	1,060,442
14		Account 283 - Deferred Income Taxes - Other					
15	28305000	Legal Liability-Lease on G.O. Bldg. - Fed		0		0	0
16	28306000	Legal Liability-Lease on G.O. Bldg. - St		0		0	0
17		Total Account 283		0		0	0
18		Total Accumulated Deferred Taxes		(422,195,373)		(421,100,593)	1,094,779
19		Account 282 - Deferred Income Taxes-Property & Excess Deferred Income Taxes					
20		ADIT Federal Property (2022)	OCA 1-008, Attachment E, Page 2	(374,315,277)		(374,315,277)	0
21		Less: Federal Property Flow-Through (2022)	OCA 1-008, Attachment E, Page 2	34,312,475		34,312,475	0
22		EDIT Federal Property	OCA 1-008, Attachment A, Page 4	(163,628,980)	/ 2	(162,568,538)	1,060,441
23		Normalization Adj	Exhibit 107, Page 5b	10,523,251		10,523,251	0
24		Book/Tax Depreciation Forecast Adjustment		852,890		852,890	0
25		Total ADIT & EDIT - Property		(492,255,640)		(491,195,199)	1,060,441

R. DANHIRES

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
RIBEKA DANHIRES
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

I. Introduction

Q. Please state your name and business address.

A. Ribeka Danhires, 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, Rates & Regulatory Service.

Q. What are your responsibilities as Manager, Regulatory Policy?

A. I am responsible for managing Columbia's rates and regulatory activity before the Pennsylvania Public Utility Commission ("Commission"). This responsibility includes ensuring timely, accurate rate and regulatory filings before the Commission 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").

Q. Please describe your professional experience.

A. I hold a Bachelor of Arts degree in Accounting from the University of Pittsburgh and a Master's of Business Administration degree from Seton Hill University. After graduating from college, I was employed by Duquesne Light Company for ten years. I started in the Rates & Tariff Services Department as a Rates Analyst and concluded my time at Duquesne Light Company in the Regulatory Affairs Department as the Pennsylvania State Regulatory Coordinator. I joined Columbia in December 2015 as a Senior Rate Analyst and moved into my current role as Manager, Rates & Regulatory Service in September 2018.

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

A. Yes. While I have only testified before the Pennsylvania Public Utility Commission in various customer complaint matters, I submitted direct testimony and testified in support of Columbia Gas of Maryland's ("CMD's") 2016, 2017, 2018, 2019 & 2020 Purchased Gas Adjustment ("PGA") filings before the Maryland Public Service Commission in Case Nos. 9510(j), 9510(k), 9510(l), 9510(m) and 9510(n), respectively. I submitted direct testimony in support of the settlement in CMD's 2019-2023 Strategic Infrastructure Development and Enhancement Plan in Case No. 9479. And, I provided testimony in CMD's 2018 Rate Case, Case No. 9480, as the Tariff witness.

Q. Please explain the purpose of your Direct Testimony in this proceeding.

A. My purpose in this proceeding is to present and sponsor Columbia's proposed tariff changes. My testimony lists the exhibits that I am sponsoring as well as a high-level explanation of the proposed tariff revisions. The details of those proposed tariff changes can be found in Exhibit 14, Schedule 2, Attachments B and C.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

Exhibit No.:	Description:
Exhibit No. 10, Schedule 4 (39)	Company policy with respect to relationship with potential customers.
Exhibit No. 14, Schedule 1 (26)	List of information provided to the Commission.
Exhibit No. 14, Schedule 2 (6)	Present and proposed tariff pages.
Exhibit No. 15, Schedule 1 (01)	Corporate history, list of counties and municipalities served and total population in areas served.
Exhibit No. 15, Schedule 2 (02)	System map.
Exhibit No. 114, Schedule 1 (26) (6)	List of information provided to the Commission and tariffs, both present and proposed.
Exhibit No. 115 (01) (02) (24)	Corporate history, system map and affiliate relationships.

II. Tariff Changes Summary

Q. Please provide a brief description of Columbia's proposed tariff changes.

A. There are several proposed tariff changes. The substantive tariff changes proposed in Supplement No. 325 include base rate revisions. In addition to the base rate revisions, Columbia is proposing two new rate riders - the Revenue Normalization Adjustment ("Rider RNA") and the Federal Tax Reform Adjustment ("FTRA"). Columbia is also proposing to amend its Capital Expenditure Policy so that agreements with applicants for commercial and industrial distribution service could be based upon minimum revenue requirements in addition to, or in lieu of, minimum use requirements. Further, Columbia proposes to expand its Rules and Regulations to include a comprehensive gas quality standard with a focus on renewable natural gas ("RNG"). All substantive changes reflect a "(C)" in the right margin of the page. Several non-substantive changes, such as formatting, also are included.

Q. Please provide a listing of all the tariff changes available.

A. Tariff pages 2 through 2b, within Exhibit 14, Schedule 2, Attachments B and C, present the List of Changes to the Tariff proposed in this base rate case.

III. Non-Substantive Tariff Changes

Q. Please explain the formatting changes.

A. The headers on each Tariff page have been updated to reflect Supplement No. 325 and the sequence of each page number has increased by one from the previously filed supplement number for each individual page. The "Issued" date and the "Effective" date in the footer on each Tariff page now reflect "March 30, 2021" and "May 29, 2021", respectively. The President, where applicable, has also been updated in the footer to reflect Columbia's current president, Mark Kempic. Additionally, as shown in the Table of Contents on page 3 of the tariff, the blank space between sections 1 and 2 of the Rules and Regulations has been removed and the pages held for future use have been revised to now include pages 72 through 75 of the tariff. Page 71 of the tariff is now used to propose the Quality of Gas Delivered to Company which will be explained in more detail as one of the "Substantive Tariff Changes".

IV. Substantive Tariff Changes

Q. Please explain the changes to rates within Supplement No. 325 as shown on the "Rate Summary" pages.

A. The "Rate Summary" pages are shown as pages 16 through 19. These pages contain the rate components and the total effective rate for each of the Company's rate schedules. The changes to each rate schedule, by page, will be described below.

Page 16, which details the rates for residential sales service and Choice service (Rate Schedules RSS and RDS), reflects increases to the Customer Charge, Distribution Charge, Gas Supply Charge and Pass-through Charge, whereas the Distribution System Improvement Charge ("Rider DSIC") has been reset to zero. A column for the newly proposed Rider RNA has been added to page 16 and the column that used to reflect the "Federal Tax Adjustment Credit (FTAC)" has been renamed the "Federal Tax Reform Adjustment" ("FTRA").

Commercial and industrial accounts using less than or equal to 64,400 therms per year normally fall into one of three rate schedules depending on their choice of service. Rate Small General Sales Service ("SGSS") reflects the rates for customers purchasing their gas supply from the Company, while Rate Small Commercial Distribution ("SCD") and Rate Small General Distribution Service ("SGDS") are tariffed rate schedules for the mandatory firm capacity Choice program and the Gas Distribution Service program respectively, which are for customers choosing to purchase their gas from a natural gas supplier. Rate Summary page 17, which contains the rates for these rate schedules, reflects an increase to the Customer Charge, the Distribution Charge and Gas Supply Charge, and a reset of Rider DSIC to zero. The FTAC has been renamed FTRA.

Rate Summary page 18 contains customer and distribution charge rates for commercial and industrial customers using more than 64,400 therms per year. Rate Schedule Large General Sales Service ("LGSS") is for those customers who purchase their gas supply from Columbia. Rate Schedules Small Distribution Service ("SDS") and Large Distribution Service ("LDS") are rates for customers purchasing gas from suppliers. This page reflects increases to the Customer Charge, the Distribution Charge and the Gas Supply Charge, and a reset of Rider DSIC to zero, for all rate schedules. The FTAC has been renamed FTRA.

Rate Schedules Main Line Sales Service ("MLSS") and Main Line Distribution Service ("MLDS") are for customers who receive either sales service or distribution service, respectively, and are within two (2) miles of an interstate pipeline or are served directly from an interstate pipeline through a "dual purpose" meter. Columbia is not proposing any changes to the Customer Charge and Distribution Charge rates for these customers, however, Rider DSIC is being reset to zero for these customers and the Gas Supply Charge has increased, as reflected on page 19. The FTAC has been renamed FTRA.

Q. Please explain the changes on the remaining "Summary" pages.

A. The remaining "Summary" pages include pages 20 through 21c.

The "Other Rates Summary", page 20, shows increases to the Price-to-Compare for both residential and commercial gas supply. Those increases are a direct result of the increase to the Gas Procurement Charge ("Rider GPC") and the Merchant Function Charge ("Rider MFC") rates. The "Gas Supply Charge Summary" on page 21a and the "Price-to-Compare Summary" on page 21c includes these increases too. Page 20 also reflects the name change to the existing FTAC which has been renamed FTRA.

Page 21, which is the "Rider Summary", reflects an increase to the Rider Universal Service Plan ("Rider USP") rate, the Rider GPC rate and the Rider MFC rate and a decrease to the Rider DSIC percentage. The "Rider Summary" page also includes a new line for Rider RNA.

The residential rates included on the "Pass-through Charge Summary" on page 21b are impacted by the Rider USP increase which causes the rate in the "Total Pass-through" column to increase for Rate Schedules RSS and RDS.

The rate change for Rider GPC, the Rider MFC percentage and the Rider DSIC percentages are included on Tariff pages 160, 161 and 177 respectively, which are the tariff pages that describe each rider.

Q. Pages 16 and 20 of the tariff designate a location for Rider RNA, however, a rate is not indicated. Please explain.

A. As indicated in the description of Rider RNA on pages 144 and 145 of the Tariff, the Company is not proposing to bill Rider RNA until the October 2022 billing cycle.

Columbia has filed the proposed Tariff with an effective date of May 29, 2021, and at that time a rate for Rider RNA will not be billed. Therefore, it is appropriate that Rider RNA rate is not specified in the Tariff at this time.

Q. Pages 16 through 20 of the tariff designate a location for the FTRA, however, a rate is not indicated. Please explain.

A. As described in Witness Harding's testimony (Columbia Statement No. 10), the Company is not proposing an adjustment in this case. Rather, the Company is proposing a rider to allow the Company to make any future adjustments to its federal taxes outside of a base rate case. Columbia has filed the proposed tariff with an effective date of May 29, 2021 to allow for the rider to become effective should it be needed. Therefore, it is appropriate that a specific adjustment is not specified in the Tariff at this time. The FTRA replaces the FTAC on page 164 of the Company's tariff.

Q. Where do the rate changes contained in your testimony originate?

A. The rate changes affecting the Customer Charge and Distribution Charge for each rate schedule can be found within Exhibit No. 103, Schedule No. 8 pages 5 through 9. The rate change to Rider USP can be found on page 5 within that same exhibit and schedule. Rider GPC and Rider MFC rate changes are shown in Exhibit No. 103, Schedule No. 7, pages 7 and 8. The rate design contained in Exhibit No. 103 is also discussed in Company Witness Notestone's testimony (Columbia Statement No. 11). The percentages for Rider MFC are identified in Exhibit MJB-1 attached to Company witness Bell's testimony (Columbia Statement No. 3).

Q. The Company's tariff includes a proposal for Rider RNA. Please explain.

A. Company witness Notestone's testimony, Statement No. 11, introduces and explains Rider RNA which Columbia proposes to be applicable to non-CAP residential customers under Rate Schedules RSS and RDS. Rider RNA has been added to the Company's tariff on pages 144 and 145.

Q. The Company's tariff includes a proposal to continue the Rider WNA for an additional five years. Please explain.

A. Company witness Notestone's testimony addresses this proposal, but essentially, the Rider WNA will expire upon the issuance of a final order in this case unless the Commission authorizes Columbia to continue the rider. Columbia is proposing to continue the Rider WNA until a final order is entered in the Company's first rate case filed after May 31, 2026. This has been revised on page 162 of the Company's tariff.

Q. The Company's tariff includes a proposal for FTRA. Please explain.

A. Company witness Harding's testimony, Statement No. 10, introduces and explains the need for a rider to adjust for federal taxes, when applicable. The FTRA has been added to the Company's tariff, replacing the existing FTAC on page 164.

Q. Please explain the reason for minimum use agreements that are authorized under Columbia's Tariff provisions regarding Commercial and Industrial Distribution Service.

A. Tariff Section 8.2.2, on page 49 of the Company's tariff, requires an applicant for commercial or industrial distribution service to provide a deposit to the Company that is equal to difference between the minimum capital investment required to serve the applicant's gas requirements and the amount of capital that the Company can justify investing in the project, based on the applicant's anticipated gas requirements. Where anticipated gas requirements justify a project without the need for a deposit, subpart (a) of Section 8.2.2 allows the Company to employ minimum use agreements as a means of guarding against actual gas usage that falls short of those anticipated requirements. Subpart (b), which addresses situations where anticipated gas requirements do not justify an extension of facilities without further customer participation in the project, also permits the Company to employ minimum use agreements to guard against actual gas usage falling short of anticipated gas requirements.

Q. You are proposing to add the phrase "or (2) a minimum revenue agreement, in which applicant contractually agrees to pay a minimum amount over the term of the agreement" to subparts (a) and (b) of Tariff Section 8.2.2. Why?

A. Currently, minimum use agreements are based upon anticipated revenues that are derived from an analysis that uses current rates. In the event of a base rate increase, a customer who complies with their minimum use obligation under such an agreement could end up paying more than the original contract anticipated as the revenue that is required to justify Columbia's investment. Therefore, Columbia seeks approval to employ either a "minimum use" or "minimum revenue agreement" so that the Company may use agreements that focus on the minimum revenue needed to justify its investment to serve applicants in lieu of minimum use. An agreement that uses revenue as the measuring stick, rather than usage, will continue to protect the Company from the risk of unjustified capital investments where anticipated usage does not come to fruition, while also protecting customers from being required to pay more than the amount that would justify the investment to serve them.

Q. The Company's tariff includes a proposal to include a standard gas quality section under its Rules and Regulations with a focus on RNG. Please explain.

A. The changes will allow Columbia to have a more comprehensive gas quality standard dependent upon the origin of natural gas entering Columbia's system. More specifically, these changes provide for a more detailed list of particulate and gas compounds and levels that Columbia will require any gas to meet when introduced into its system. Likewise, these standards provide for a more formalized gas quality testing methodology to ensure that any supplier providing gas to Columbia's system has a clear understanding of testing requirements. Finally, the standards set forth the multiple origins of natural gas supply and define which chemical and particulate standards would likely apply to the natural gas origin. The Quality of Gas section has been added to the Company's tariff on pages 71 through 71d.

Q. Does this complete your Prepared Direct Testimony?

A. Yes.

D. DAVIS

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

TABLE OF CONTENTS

I. Introduction

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 Columbia'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 at a community-based agency assisting low income clients with accessing utility service and providing other basic life necessities. I was hired by Columbia as a Community Relations representative and subsequently became Manager of the Customer Programs Department. My titles have changed over the years, but I have remained in a similar function throughout my 28-year career at Columbia.

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

A. I will provide a summary of customer initiatives in 2020 and the Company's plans to improve its budget program as a result of the 2020 rate case. I will also provide an update to the Company's response to the impacts of COVID-19 on its customers. Pursuant to Columbia's 2016 rate case Joint Stipulation and Settlement, paragraph 41[1], I will provide an update on Columbia's efforts to increase voluntary contributions to Columbia's Hardship Fund. Finally, I will address the Commission's final order in the Company's 2020 rate case (R-2020-3018835) to the extent it addresses universal service programs. I will specifically provide an update on the Company's outreach to low income customers to enroll in the Hardship Fund program, as directed in the 2020 rate case order.

II. Customer Initiatives & the Company's COVID-19 Response

Q. Please explain any new initiatives that the Company has implemented to improve the customer experience?

A. There were several new initiatives that the Company implemented in 2020 to improve customer service.

One initiative was the new customer "welcome" emails. When new and transfer customers start service with the Company, Columbia now sends a series of four emails welcoming them as customer, sharing useful resources and information, and providing natural gas safety information.

Another Company initiative made it easier and quicker for customers to pay their bill with a checking account by having their payment information automatically populate during the payment process. Columbia also improved its

[1] Docket No. R-2016-2529660 (Order Entered October 27, 2016).

AutoPay process by adding PayPal, Amazon Pay and Venmo as payment options. Columbia also updated and improved billing and payment alerts to customers.

Columbia also made improvements to its website. The Company's website now has Google Translate prior to website self-service log-in. The website also now has the ability for customers to enroll in COVID-19 payment plans digitally. In addition, the Company improved the visibility of energy usage information on the customer's web dashboard and made improvements to the budget billing plan explanations on its website.

Columbia's online CAP application also went live in 2021, so now customers have another method in which to apply to the CAP program.

Q. Please explain the planned changes to the budget billing program.

A. In the Company's 2020 rate case, Columbia proposed to revise its budget billing program to offer customers a rolling 12-month payment plan. With the Commission's approval of the case, the Company is moving forward with the necessary programming to update the budget billing program. This update will allow customers to enroll in the budget billing program at any time during the year and have a payment plan equal to $1/12^{th}$ of their expected annual bill. This new enhanced program will continue to be compliant with existing regulations by not having a true up during the winter months and adjusting the bill periodically to minimize a large true up at the cycle's end.

Q. Please explain how the Company has supported customers in response to the COVID-19 Pandemic.

A. The Company has adapted many of its policies and procedures, as well as implemented additional initiatives, to assist customers who have been affected by the pandemic. Specifically, I will address the following areas: Customer Education and Outreach; Termination/Billing/Flexible Payment Plans; Universal Services and Other Assistance Programs; and Waiver of Fees.

<u>Customer Education and Outreach:</u>

Q. Please provide descriptions and/or examples of Columbia's education and outreach to its customers about their rights and responsibilities, available assistance programs, and energy efficiency and conservation opportunities during the COVID-19 pandemic.

A. Columbia has used several different resources to educate customers regarding the Company's current collection practices and available assistance programs. Examples include:

- Social media posts on Facebook and Twitter;
- Targeted outbound calls for Low Income Home Energy Assistance Program ("LIHEAP") recovery CRISIS program;
- E-mails to customers that may be eligible for the LIHEAP recovery CRISIS program;
- E-mails to customers regarding current collection practices;

- Updated information on its website regarding available programs;
- Announcement on its website that the Company has suspended all terminations for non-payment;
- Bill inserts; and
- Customer Newsletters.

Q. Are there any other efforts you would like to highlight?

A. Yes. The Company made outbound calls to customers who were determined to be eligible for the LIHEAP Recovery CRISIS program. The purpose of the call was to obtain customer consent to apply to the LIHEAP program on their behalf. Of the 7,048 accounts that Columbia reviewed, 4,544 customers were identified that qualified for assistance. Multiple phone calls were made to each customer over several weeks, and Company representatives were able to receive authorization to apply for funds on behalf of 947 customers. The Company ultimately received LIHEAP Recovery CRISIS assistance for 1,376 customers for a total of $405,142. Thus, the Company's outbound calling campaign was responsible for 68% of the grants received in 2020.

<u>Termination/Billing/ Flexible Payment Plans:</u>

Q. Is the Company currently terminating service to its customers?

A. Columbia ceased performing customer shut-offs for all customers on March 13, 2020, consistent with the Pennsylvania Public Utility Commission's ("Commission") March 13, 2020 Emergency Order at Docket M-2020-3019244.

Although the Commission lifted the absolute termination moratorium as of November 9, 2020, the Company has not terminated customers.

Q. Does the Company intend to resume service terminations in April once the winter protections expire?

A. Yes. The Company has sent pre-10 day communication letters to those customers that will be subject to termination of service beginning in April 2021. Subsequently, the Company will send out termination notices to customers, as authorized and as required, if they are still at risk for termination at least ten days prior to any termination of service.

Q. What types of payment arrangements did Columbia offer during the pandemic?

A. For residential customers, the Company offered two options in 2020. In addition to Columbia's normal budget plus payment plan offered to its customers based on financial information and household size, the Company provided customers the option of a six month payment plan that allowed customers to pay their current bills, plus 1/6 of their arrears.

In May 2020, the Company began offering commercial customers with arrears of more than $90 and less than $600 a 6 month payment plan. This payment plan option was intended for customers who are normally not payment troubled and financial information was not required for enrollment in this plan. Pursuant to the Commission's October 13, 2020 Order at Docket No. M-2020-

3019244, Columbia began offering small commercial customers an extended 18 month payment plan.

<u>Universal Services Programs and Other Assistance Programs:</u>

Q. Is the Company currently removing customers from the Customer Assistance Program ("CAP") for failure to verify their incomes?

A. No. While CAP participants are subject to removal from CAP if they do not verify their income eligibility annually, Columbia is currently not removing customers from CAP if they do not provide income verification. The Company intends to continue this temporary relief through the remainder of 2021.

Q. What changes has the Company made to CAP, or to other programs, as a result of the pandemic?

A. The Company has made the following changes to the CAP program and Hardship Fund program as a result of the pandemic:

- Customers were not removed from CAP for failing to pay their CAP bill.
- Any additional per week increase from Unemployment Compensation due to Pandemic relief funding is not/was not being counted as income in the determination of CAP eligibility since the income is short term.
- Any "stimulus" income received by customers is not being counted as income.
- Proof of income is not required at this time for CAP customers who are unable to verify income.

- The Company has also made changes to its Hardship Fund guidelines in order to assist customers during the pandemic. The Hardship Fund is a fund of last resort that assists customers in maintaining or restoring their service with a maximum grant of $500 and is typically available to customers who are at or below 200% of poverty and have arrears. In response to the pandemic, the Company is waiving the requirement of a sincere payment effort and, therefore, no payment is required in order to be eligible for hardship funds. Second, all low income customers are eligible regardless of CAP status so long as their account is in arrears.

Q. Will the Company continue these practices for the duration of 2021?

A. The Company will continue to not count stimulus money, including temporary increases to unemployment compensation, as household income for potential CAP customers. The Company will also accept self-certification of income for CAP eligibility if income documentation is unavailable.

The changes to the Hardship Fund eligibility guidelines will remain in effect through the program year ending September 2021. This includes eliminating the sincere effort of payment and ensuring all customers are eligible regardless of CAP status so long as their account is in arrears.

The Company will also begin actively collecting on delinquent CAP accounts as described in its approved USECP on or after April 1, 2021. The Company will continue to promote all available programs to customers through its contact center, website and social media postings.

Q. Are there other assistance programs that Columbia developed as a result of the COVID 19 pandemic?

A. Yes. On April 24, 2020, the Company filed a petition for approval of a temporary customer grant program aimed at assisting residential customers not eligible for Columbia's low income customer programs. The temporary grant program would have provided customers with grants up to $400 to reduce arrears and offer credit counseling. This petition was denied by the Commission on July 16, 2020. In response to this denial, the Company sought and obtained Commission approval to temporarily expand the Hardship Fund income guidelines from 200% of FPIG to 300% FPIG in an effort to provide relief to those struggling as a result of the Covid-19 pandemic but who are slightly over the income guidelines. Columbia shareholders donated an additional $400,000 to help fund the expansion. This was approved on November 17, 2020 and was implemented on December 15, 2020.

<u>Waiver of Fees</u>:

Q. Please summarize the fees that are being waived as a result of the pandemic.

A. Policies for late fees and reconnect fees have been modified, as per below:

Late Payment Fees: The Company has waived all late payment fees since April 2020. Since then, late fees in excess of $1,800,000 have been waived for customers.

Reconnect Fees: Columbia's normal policy is to waive the $24 reconnect fee for customers who are identified as having a household income of less than 150% FPIG. However, during the COVID-19 pandemic, Columbia has expanded that policy and is waiving the reconnect fees for customers who contact the Company to have service restored and are identified as payment troubled. Some customers during the pandemic have experienced a loss in income, thereby becoming payment troubled, yet still remain above 150% of FPIG and may or may not be eligible for energy assistance. Additionally, for customers who have been previously disconnected for lack of payment, and who would normally be charged a reconnect fee prior to reconnection, the Company is using discretion in applying the reconnect fee to the customer's first bill if the customer informs us that an upfront payment would result in financial hardship due to loss in income experienced during the pandemic.

III. Hardship Fund Program Update

Q. Please explain Columbia's Hardship Fund program.

A. The Hardship Fund is a Columbia-sponsored fuel fund that provides financial assistance through grants to low-income, payment-troubled residential customers, and is administered by the Dollar Energy Fund ("DEF"). Columbia's Hardship

Fund program is a fund of last resort providing cash assistance to eligible customers to reduce arrears, reconnect service or stay a service termination. To be eligible, a customer's household income must be less than 200% of the Federal Poverty Income Guidelines ("FPIG"), the customer must be a residential heat customer, and the customer must demonstrate an imminent need due to a pending termination notice, overdue arrears or loss of service and finally, the customer must show that he or she has made a sincere effort to pay at least some of his or her bill in the last 90 days.

Over the past ten years, the average Hardship Fund grant provided to Columbia customers has ranged from $370 to $410. The DEF administers the program, which includes developing and maintaining an online application and database system for processing Hardship Fund applications. DEF contracts with various community-based agencies throughout Columbia's service territory to accept applications, which are then reviewed by the Company and DEF personnel for approval. As stated earlier in my testimony, in 2020 the Company implemented an on-line CAP application, but customers can use the on-line application to apply for the Hardship Fund program too. The on-line application makes it very convenient for customers to apply for the program because they no longer have to go to an agency or speak with a DEF representative.

Q. How does Columbia fund its Hardship Fund program?

A. Columbia contributes one dollar of shareholder money for every dollar contributed by its customers to its Hardship Fund. Annually, through fundraising efforts, Columbia raises between $125,000 and $150,000 in customer contributions. Combined with the shareholder match, typically about $300,000 is contributed by customers and Columbia towards the accounts of Columbia's payment-troubled, low-income customers through the Hardship Fund. Columbia also has Commission approval to use the residential portion of federal pipeline penalty credits and supplier refunds to supplement the Hardship Fund up to $375,000 annually. Columbia is permitted to maintain a balance of up to $750,000 from pipeline penalty credits and supplier refunds for funding for the Hardship Fund.[2]

Q. What is the current balance of the pipeline penalty credits and supplier refunds to be used to supplement the Hardship Fund?

A. The current balance is $336,098.28. The Company made its annual transfer of $375,000 to the DEF in January 2021. The Company anticipates adding to the fund balance when additional pipeline penalty credits and supplier refunds are received.

Q. What is the primary source of voluntary contributions for the Hardship Fund?

A. The primary source of voluntary contributions for the Hardship Fund is the Company's "Add a Buck" campaign, which solicits voluntary donations from

[2] If the amount of the residential portion of the pipeline penalty credits and supplier refunds received by Columbia exceed the $750,000 maximum balance, the excess funds are passed back to residential customers through gas cost rates.

customers via a message on their bills. Columbia's "Add a Buck" campaign has raised the following amounts over the past years:

Year	Total Customer Bill contribution
2010	$73,803.22
2011	$76,566.00
2012	$73,094.50
2013	$70,798.26
2014	$63,494.50
2015	$74,001.50
2016	$68,819.00
2017	$68,249.00
2018	$62,282.00
2019	$57,229.00
2020	$68,043.50

Q. Please provide a history of the Company's efforts to promote its Hardship Fund and raise donations for the Fund.

A. Columbia has a long history of seeking alternative ways to fund its Hardship Fund including:

- In 1998, the Company formalized its Gift of Energy Certificate program. The Company incentivizes customers, friends and family to purchase gifts of energy for other Columbia customers to be credited to low-income customer accounts. A total of all Gifts of Energy sold are matched and donated to the DEF by Columbia's shareholders.

- In 1998 and 1999, the Company contracted to sell antique miniature replicas of two different models of company trucks with $5.00 of every purchase donated to the DEF.
- In 2002, the Company sponsored the City of Pittsburgh, Light Up Night Warm Up tent promoting the DEF and soliciting donations.
- In 2002 and 2003, the Company purchased radio ad time to promote donations to the DEF.
- In 2004, the Company partnered with the Punxsutawney Groundhog Club to develop and implement an online donation campaign. The campaign solicited raffle prizes for online donations, while the Groundhog took a vacation throughout Pennsylvania asking people to donate online to the DEF and documenting his travels on the campaign website. Radio ads and web ads were used to promote the campaign and solicit donations.
- In 2006, the Company started a long-standing annual partnership with the Trans-Siberian Orchestra ("TSO"). A donation is made to the DEF for every ticket sold. This sponsorship continues today.
- Also in 2006, the Company was a primary sponsor of the Irish Heritage Festival and negotiated the opportunity to promote the DEF and provide donation opportunities at the two-day event.
- In 2007, the Company sponsored a theatrical performance of *Edward Scissorhands* with a dollar for every ticket purchased going to the DEF.

- During the heating season in 2008 and 2009, Columbia contracted with the Pittsburgh Penguins with the Check the Box campaign. Every time a player was sent to the penalty box, an announcer reminded attendees to check the box on the gas bill for a monthly pledge to DEF. Additional radio spots were used to promote the program as well.
- In 2012 and 2013, the Company sent thank you letters signed by the DEF Executive Director and Columbia's President to the prior year's donors.
- In 2015 and 2016, the Company sponsored a hot oatmeal breakfast for employees where donations were requested for the DEF as an avenue to increase funds for the Cool Down for Warmth promotion.
- In 2016, the Company held poverty simulations with operations employees and included DEF personnel asking them to speak about their organization and its mission.
- In 2017, Columbia held a campaign to increase E-Bill participation. An incentive for signing up was a $5.00 contribution to the Dollar Energy Fund. The Company raised $4,900 through this effort with 980 new E-bill participants.
- Also in 2017 and 2018, the Company partnered with Nest Thermostat Labs, to promote Nest thermostat use. For every Nest Thermostat purchased as a result of this campaign, a donation was made to the Dollar Energy Fund.

Despite numerous email blasts, web mentions and social media promotions, less than $10,000 was raised over the two years.

- In 2018 Columbia initiated a fundraising opportunity at Top Golf in Bridgeville, PA. Held in the fall, this fundraiser capitalized on existing contacts with Dollar Energy Fund's summer golf outing as well as brings in new donors that Company employees invite. The event was held in 2018 and in 2019 and raised a combined total of $26,980, resulting from sponsorships, participants and gift baskets generously donated by Company employees.

Q. Does the Company participate in Dollar Energy Fund sponsored/developed fundraisers?

A. Yes. Over the years, the DEF has developed and sponsored various fundraisers. The proceeds of these events are divided among participating utilities. Specific events in which Columbia has participated include:

- Station Square – Pittsburgh Light Up Night – Columbia provided volunteers to staff the event.
- Westmoreland County Light Up Night – Columbia assisted in planning and staffing the event.
- Duquesne vs. Pitt basketball game donation at the door event – Columbia provided volunteers to collect money at the entrances.

- Warmathon radio call-in campaign — Columbia provides sponsorship money and volunteers to answer telephone calls.
- Cool Down for Warmth - Now in its seventh year, Columbia's President has participated for two years, Columbia's Assistant General Counsel participated in 2017 and in the past four years, a new group of dedicated employees participate to raise funds by sitting in a house made of ice until they reach their contribution goal through donations from family, friends and co-workers.
- DEF Golf Outing - Columbia Gas sponsors this event and sponsors two teams.
- DEF Request a Thon, a partnership with a local radio station has been the newest initiative beginning in 2018. Listeners can call in to the station and make a pledge and hear their song request on the air. Columbia's sponsorship extends to this effort as well.

Q. Are there any other yearly promotions Columbia participates in to promote its Hardship Fund?

A. Yes, the following activities occur annually:

- Bill insert in December requesting donations;
- Social Media posts on Facebook and Twitter about events and requesting donations;
- E-mail blast requesting donations yearly;

- Coupon on paper bill and E-bill copy to those who have not yet signed up for monthly donations;
- Website postings which explain how and where to contribute; and
- Annual Thank you letter or post card to existing donors from the President of Columbia Gas and The CEO of the Dollar Energy Fund.

Q. Does Columbia continue to seek and support new opportunities to promote the Hardship Fund and donations to Dollar Energy Fund?

A. Yes. Last year, 2020, was a difficult year to fundraise due to the COVID 19 pandemic restrictions on large gatherings of people. The Tran Siberian Orchestra concert was cancelled and the Top Golf fundraiser was not possible. Columbia reacted to this by doing alternative fundraising and awareness activities. Columbia partnered with Steel City Radio and WQED to sponsor TSO Re-imagined which broadcast past concerts and had live interviews and segments to promote the TSO during the holidays. The DEF was provided on-air segments and ads to encourage donations.

Additionally, Columbia developed and marketed "Digger Dog" craft kits for kids with proceeds of each kit sold going to the DEF. This initiative was promoted on our website, Dollar Energy's website, with social media posts and to our Universal Service Advisory Council.

IV. <u>CAP Outreach & Collection Issues</u>

Q. Are there any other issues you would like to address?

A. Yes. I will address the Commission's final order in the Company's 2020 rate case to the extent it addressed Universal Service programs.

Q. Please summarize the issue raised regarding CAP outreach.

A. Essentially, there was feedback that the Company should expand its efforts to more effectively target the lowest income customers with incomes at or below 50% FPIG.

Q. Do you agree that the Company needs to expand its outreach efforts?

A. The Company endeavors to implement new outreach avenues on a regular basis and will continue to do so. The Company met with its Universal Service Advisory Council ("USAC") in April 2020 and again in October, 2020. The agenda for both meetings included a review of existing and planned outreach activities. At both times, the Company asked for feedback and recommendations. The Company will continue to meet with its USAC regarding outreach to identify potential improvements. While the Company recognizes the importance of investigating ways to improve outreach, the Company notes that its CAP participation rates are not below that of other Pennsylvania utilities.

Q. Does the Company specifically target customers between 0 and 50% of poverty?

A. The Company utilizes a broad range of outreach efforts and opportunities to reach all low income customers. Columbia partners with other utilities on outreach initiatives and often mirrors similar events held by other utilities across the state to reach out to customers. The 2019 USRR reports Columbia has the second highest number of customers between 0 and 50% of poverty enrolled in CAP of all gas utilities. Currently, the Company has 5,921 customers enrolled in CAP that are between 0 and 50% of poverty which is 25% of all CAP customers. Nevertheless, the Company has already implemented several changes and will be consulting with its USAC this year to examine further outreach efforts focused on those in the lowest poverty levels.

Q. Please explain the changes that have been made in the last year that may increase CAP participation from customers within this lowest poverty guideline?

A. In its last Universal Service and Energy Conservation Plan, the Company agreed to change reverification of customers with zero income from three to six months. In addition, the Company implemented an on line application for customers to complete without having to make a phone call to the Company or a screening agency. The application went on line December 1st and in the first three months of operation, 105 customers were enrolled via the on line application. The Company plans to promote this new opportunity as soon as the existing process is streamlined and optimized. The Company is projecting a campaign as early as April, 2021.

Q. Are there any other new strategies the Company will be implementing to promote programs?

A. Yes, the Company will be reviewing its website to ensure programs information is visible and accessible to any customers looking for information on its website. In addition, the Company will be creating an ad campaign focused on energy efficiency and educating customers on the importance of reducing energy usage and what Columbia can do to help customers conserve energy.

Q. Please summarize the issues raised related to CAP collections.

A. The Commission's 2020 base rate case order concluded that "the manner in which Columbia conducts collection activity for CAP accounts presents some concerns and that Columbia should submit to its USAC, within six months of the entry of this Opinion and Order, the question of how customer payments on CAP bills can be pursued through a reasonable collections process, consistent with the OCA's recommendation." The order questions whether the Company is following Commission advice to conduct timely collections of CAP customers to ensure a balance does not accrue beyond an ability to catch up.

Q. Do you agree with the Commission recommendation that timely collections are important to ensure balances do not accrue?

A. Yes. The Company put into place its current collections policies based on feedback from the Commission as early as 1996. At that time, the Commission recommended the Company not only remove customers from the CAP program for failure to pay, but first terminate service as a response to non-payment. The Commission also recommended prioritizing CAP accounts after two missed payments for shut off. The Company complied with both of these recommendations and these remain in the Company's plan today. However, due to the requirement to terminate service for failing to pay, the Company must also follow all collections regulations established for all residential customers. Therefore, a CRISIS grant will delay a termination until at least May of each year, a medical certificate will delay collections, a complaint filed with the Commission will delay collections activity and finally no collections occurs on CAP accounts from December 1 through April 1. Additionally the month of November is limited in collections due to holidays and temperatures. These all impact timely collections. The Company made the decision to accept the maximum the Department of Human Services (DHS) will authorize for CRISIS in an effort to assist the customer with bill payment regardless if it pays the entire CAP amount owed. This benefits the customer, however, it will lead to delayed collections.

Q. What is the status of CAP accounts today?

A. The Company has experienced a further decline in payments to billing. Due to the Pandemic, there were minimal collections activities occurring in 2020. Instead, the Company focused on extensive outreach efforts to promote the programs available for assistance. However, customer engagement was very low, which was experienced by most utilities and evidenced by low LIHEAP CARES Act applications. The Company received 65% payments of CAP bills in 2020. Recent statistics show 68% of customers billed in February, 2021 were current on their

CAP payment plan or had a credit and another 6% of customers owed less than one month's bill. 619 customers had arrears over $800 suggesting that CRISIS could assist the majority of customers to reduce their arrears if they apply for assistance. In total, 12% of CAP customers have arrears over $300.

Q. Please summarize the actions the Company is prepared to take to address the concerns raised by the Commission.

A. The Company will present a detailed review of its current CAP collections policies at its next Universal Service Advisory Council meeting in April 2021. As part of the response to the Company's management audit, the Company will convene a team of interdepartmental personnel representing Universal Services, Regulatory Compliance, Meter to cash and operations personnel to develop a plan to improve overall collections with implementation to begin in April, 2022. The Company will present its plan to its Universal Service Advisory Council at its October 2021 meeting and solicit feedback.

Q. Please address the Commissions directive to explain Columbia's efforts to promote the Hardship Fund program to low income customers?

A. The Hardship Fund was promoted beginning in October 2020 with multiple channels. Information was included in the various forms of legislative events and forums, The Company held a virtual town hall with legislative offices and community based agencies to explain programs including the Hardship Fund, information was posted on the Company's website, the Company posted information on various social media channels. In addition, the Company implemented an online application for Hardship funds in conjunction with its CAP on line application. Finally, all low income customers are eligible for assistance regardless of CAP status. As of February, 28, 2021, 767 customers have received grants as compared to 356 customers during the same program time frame in 2020.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 13-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

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. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding related to Universal Service Programs provided by Mr. Roger Colton of the Office of Consumer Advocate ("OCA"), Mr. Harry Geller of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") and Mr. Eugene Brady of the Pennsylvania Weatherization Providers Task Force ("PWPTF").

Q. What issues will you address related to Mr. Colton's testimony?

A. I will address Mr. Colton's recommendations to implement an additional COVID relief program. I will address Mr. Colton's concerns with the Company's CAP exits related to recertification and mobility. I will address Mr. Colton's recommendation on outreach and specifically regarding outreach to increase enrollment into CAP. Lastly, I will address Mr. Colton's recommendation to reduce its USP rider charge.

Q. Please summarize Mr. Colton's recommendations to implement an additional COVID-19 relief program.

A. Mr. Colton recommends the Company implement a similar program as it previously proposed in April 2020 with some additional cost control features. In addition, Mr. Colton recommends the Company track recipients of this new program who subsequently enter CAP and that any costs incurred be recovered through a regulatory asset in the next base rate case.

Q. Does the Company support the development, proposal and implementation of an additional COVID-19 relief program?

A. Due to the numerous resources currently available to eligible households, the Company does not support an additional COVID relief program at this time. In an effort to relieve the financial burdens Columbia's customers experienced as a result of COVID, the Company proposed and received approval from the Commission for a COVID relief program that expanded its Hardship Fund to 300% of poverty and increased the fund by $400,000 with donations by the Company. Currently, the Company has over $750,000 left in this fund to assist customers. Based on the current average grant, the Company can assist an additional 2,500 customers with existing funds.

In addition, Pennsylvania received $564 million to implement the Emergency Rental Assistance Program (ERAP) to provide rental and utility assistance for households with income at 80% of the Area Median Income ("AMI"). Based on a report shared by the LIHEAP Advisory Committee, the ERAP program's remaining funding at the end of April 2021 was $548 million. Furthermore, the

Department of Human Services (DHS) is considering several proposals to spend $50 million prior to the start of the 2022 LIHEAP fiscal year. Regardless of the decision on the method in which they intend to spend the funds, DHS has more than double the allotment to spend between now and August 2022 compared to prior years.

Lastly, the Company has heard of the potential of other available resources such Community Development Block Grants ("CDBG") grants and assistance for home owners that will provide further utility assistance to eligible households. Therefore, the resources to assist customers are already available and the implementation of an additional COVID-19 relief program would be premature, as it is not needed at this time.

Q. What are the differences between the program Mr. Colton proposes and the current Hardship Fund guidelines?

A. Mr. Colton's proposal does not explicitly offer an income guideline. The Company's prior proposal also did not include an income guideline, but rather a documented drop in income. The Hardship Fund was increased to 300% of the FPIG regardless of a drop in income. Therefore, only customers over 300% of the FPIG are excluded from assistance through the Hardship Fund which should encompass most if not all of the customers Mr. Colton's proposal was seeking to assist.

The major difference between Mr. Colton's proposal and the Company's Hardship Funds is the benefit level. Hardship Funds currently assist customers with a maximum benefit of $500. Mr. Colton's proposal recommends limiting the benefit to $200 or 25% of the customer's arrears, whichever is greater. This is more often than not, much less than a $500 benefit. The existing hardship fund would be more advantageous for customers.

Q. Is the Company recommending any initiative to assist customers affected by the COVID-19 Pandemic?

A. Yes. Although the Company recognizes there are ample funds to assist customers, it also recognizes that not all funds are being utilized. Therefore, the Company proposes a new outreach campaign to assist and link customers to available resources and promote all programs. The Campaign will include TV ads, social media and digital ads, written materials, website modifications and a pilot concierge component to assist its lowest income customers to apply for programs.

Q. Please explain the concierge component in more detail.

A. The Company will contract with a part time consultant to proactively reach out to customers with incomes less than 50% of poverty that are in arrears and have not applied for available resources. The concierge will provide individualized information to increase motivation and reduce barriers to promote program participation. When necessary, the concierge will act as an advocate on behalf of the customer with community partners to reduce barriers of participation and ease the application process.

Q. How is the Company proposing to fund this campaign?

A. The Company proposes to fund the campaign through its Rider USP for costs not to exceed $200,000 in 2022.

Q. Please summarize Mr. Colton's recommendations related to CAP exits.

A. Mr. Colton is recommending that the Commission order the Company to develop remedies for exits related to recertification and mobility.

Q. Please clarify the Company's procedures when a customer moves from one address to another.

A. Mr. Colton incorrectly assumes the Company does not transfer a customers' CAP plan and its benefits when customers move residences within the Company's service territory. The Company's current (and long standing) procedure is for its billing system to automatically transfer a customer's CAP plan to the new account without a loss of CAP benefits. In certain situations, such as when a customer connects service at a new residence prior to disconnecting at the old residence, the automatic transfer does not occur. To rectify this situation, a daily report is generated which contains a list of accounts that recently connected service and participated in CAP at the previous address. A representative manually reviews these accounts and re-enters customers into CAP without requiring customer intervention. The Company does report its highest number of defaults as a result of moving. However, this exit status is actually due to customers moving outside of the Company's service territory. The Company shares its service territory with another gas company, sometimes with two sets of lines on the same street. Therefore, it is more common for customers to move on and off company lines than may occur in other parts of the state.

Q. Please address the issue of exits related to recertification.

A. Mr. Colton is recommending the Commission order the Company to remedy what he suggests is a too high removal rate for failing to recertify. However, it is important to note that in the Company's most recent USECP proceeding, at Docket M-2018-2645401, the Commission ordered Columbia to increase the rate of recertification required by the Company. The August 8, 2019 order specifically requires income for all customers at a minimum of every three years. Prior to this change, the Company did not require a recertification of LIHEAP recipients.

I also note that in response to the pandemic, the Company stopped removing customers for failing to recertify in March 2020 and does not intend to reinstate that provision prior to December 2021. Furthermore, the Company did not require customers to provide proof of income from April 2020 through June 2021 in order to be enrolled into CAP. For these reasons, the Company expects to see an initial increase in removals from recertification, not less, once the Company resume its recertification process. Although the Company has and will take steps to reduce the burdens of income documentation for customers, the Company recognizes there may be current active CAP customers who are no longer eligible and as a result will eventually be removed from the program. This will occur at the time of recertification either by customers providing documentation verifying that they are over income or, in most cases, customers will not take any action, recognizing they will be removed after the recertification process is complete.

Q. What steps has the Company taken to reduce the burden to provide income documentation by CAP customers?

A. Traditionally, the customer is told at intake they will be required to verify their income annually or in six months if they have no income. The customer receives a letter two months before their anniversary date requesting that they mail or fax their information to the CAP administrator. The customer is also sent a reminder letter 30 days prior to their anniversary date requesting income documentation. Finally, a letter is mailed on or after their anniversary date stating that they are being removed from CAP. At any point, including after they are removed, if the customer provides income documentation verifying they are eligible for CAP, they will be recertified or re-entered into CAP.

In 2020, the Company began accepting scanned documents or pictures of income documentation emailed to the CAP administrator. Anecdotal results indicate that customers like this option; however, the Company has not been able to fully analyze results since it is not removing for failing to recertify income at this time.

The Company intends to begin to send email reminder notices that income is required as an additional communication. With this function, the customer needs only to reply to the email with proof of income either by scan or picture.

Since the Company has not removed customers for failing to verify income since March 2020, the change to the USECP has not been enforced and the Company does not know how this will affect removal rates. In addition, the ability to accept pictures of documentation and scanned documents as proof of income, as well as the future capability to send email reminder notices, will also impact recertification results. The Company respectfully suggests at this time it is too difficult to measure any one specific catalyst to affect a change (positive or negative) in the number of recertifications. Any metrics should be developed only after the Company has time to balance the current dynamics.

Q. Please address Mr. Colton's concerns related to outreach.

A. First, I note the Company is being measured on outreach efforts during a time when face to face outreach efforts were prohibited or significantly deterred. In addition, all Pennsylvania utilities as well as other program administrators, such as LIHEAP administrators, reported and experienced a decline in participation and a general lack of customer engagement in 2020.

Mr. Colton refers to comments submitted by Commissioners in early 2020, right before a stay at home mandate was issued in Pennsylvania. Mr. Colton's apparent expectation that the Company should have addressed and responded to these efforts in a meaningful way with demonstrative results is simply not reasonable. However, I would like to highlight key activities the Company has made since the Commissioners' comments were received.

- Provided a comprehensive review of its Outreach plan at the April 2020 Universal Service Advisory Council (USAC) meeting and requested feedback from council members. Attendance included representatives of the Office of Consumer Advocate, Pennsylvania Utility Law Project, and the Pennsylvania Utility Commission's Bureau of Consumer Services including Communications personnel, among other community based organizations.
- Provided updates and specific examples of outreach activities and materials in October 2020 and April 2021 to the USAC.
- Held a virtual town hall in September 2020 inviting more than 200 individuals to promote programs and provide electronic materials for dissemination to their clients/constituents.
- Hired a CARES representative with a background in Communications and program outreach to focus solely on outreach using recommendations from all stakeholders.
- Conducted one on one sessions with partners including USAC members requesting feedback and recommendations.
- Continue to refine an outreach strategy that includes all recommendations including recommendations provided in this proceeding by Mr. Colton.

Q. Please address Mr. Colton's comments related to outreach to customers with less than 50% of the Federal Poverty Income Guideline.

A. Mr. Colton suggested the Company target certain zip codes for outreach to specifically reach these customers. In 2020, the opportunities to reach customers face to face proved impossible and local events in geographic areas were either cancelled or modified due to the pandemic. As a result, the company utilized media and digital advertisements. Zip codes were targeted; however, there were funds available for more than just the lowest income zip codes. Therefore, the Company advertised more broadly. This does not suggest that the Company did not reach out to those less than 50%. Rather, in the unusual circumstances of the COVID-19 pandemic when there were limited avenues for outreach, limiting outreach to certain groups was impractical. Likewise, the Company attempted outbound calls to all customers that needed assistance, which seemed more prudent than targeting only the lowest income.

Furthermore, in 2020, due to the pandemic, the households that needed financial assistance to pay household bills expanded as people were unable to perform their jobs, or were losing vital work hours needed to pay bills. It would have been irresponsible for the Company to limit outreach to only target traditional low income populations especially since those efforts may have missed those that qualified for CAP and other programs due to recent circumstances.

Q. Mr. Colton suggests that outreach to SNAP, public assistance and SSI recipients would be beneficial to target to reach the lowest income customers. Do you agree?

A. Yes, because these groups do meet the income guidelines of available programs. However, I disagree to the extent that the Office of Consumer Advocate is recommending that each utility, assuming this is not just a recommendation for Columbia, should spend ratepayer funds on chasing down these outreach avenues individually when state entities such as the Department of Human Services could promote these programs statewide more cost effectively, and receive funds for this purpose. Utilities have overlapping territories and would therefore, have duplicative efforts with costs passed on to the same ratepayer at least twice. In addition, Mr. Colton recognizes the advantage of using trusted community advisors to disseminate information to eligible populations. Columbia agrees with Mr. Colton that a state agency already providing some assistance to a client can be a stronger referral than that of a utility to some customers. Regrettably, based on the response to Data Request OCA II-8 (Exhibit DD-1R), the OCA is missing an opportunity to encourage DHS to promote LIHEAP using these statewide channels by not providing comments to the LIHEAP plans.

Q. Please elaborate on the Company's efforts to inform its key partners of outreach efforts.

A. As mentioned above, the Company provided a detailed outline of its Outreach plan at its April 2020 USAC meeting. At that time, the Company asked for and received feedback from members including local community based agencies, the PUC's Communications representatives and members of the Bureau of Consumer Services. Most of the feedback came from community based agencies and has since been incorporated into the plan.

Q. Do you agree with Mr. Colton that the Company has a gap between eligible customers and the number of customers that participate in CAP?

A. I suspect every program will have customers that are eligible but not enrolled. It would be nearly impossible to claim a gap does not exist. However, the Company is continually measured on the percentage of customers categorized as "confirmed low income" that are in CAP, which is an erroneous comparison for two fundamental reasons. The first reason is the Commission's definition of "confirmed low income" includes self-declared income, not documented and therefore, not confirmed. Many customers do not know their gross monthly salary, forget to include their pension, or do not provide income from their small side job when they contact the Company. When they apply for CAP and are required to provide income, they either fail to follow through or they are determined ineligible at that time. The second fundamental reason is that Columbia's CAP eligibility guidelines include payment troubled. This guideline has existed since the inception of Columbia's CAP and is included to ensure customers that can afford their gas bill are not offered a subsidy paid for by non-CAP customers. Mr. Colton testified that many of Columbia's low income customers are also low usage customers. There is no value in having customers subsidize bills for other customers who can afford their entire bill or perhaps afford it with the help of a LIHEAP grant.

Q. Please summarize the Company's position related to outreach.

A. The Company has spent many resources over the years to promote programs. However, the Company recognizes other parties, including Public Utility Commissioners believe it can do better as evidenced by the Comments provided in early 2020. As a result, the Company has attempted to improve and expand its outreach efforts. However, the Company was greatly hindered by a pandemic which did not allow for community events, the subject of much of Mr. Colton's and the Office of Consumer Advocate's recommendations. The Company has hired a CARES representative to solely focus on outreach efforts. Thus far, the representative has already taken steps to understand the Company's outreach shortfalls and has begun to strengthen partnerships with grassroots agencies by reaching out to food banks, community action agencies, USAC members, agencies working with Domestic Violence victims, school districts and visiting nurses associations. The Company has incorporated the advice it received in all three USAC meetings and will continue to seek advice and recommendations with every intention to follow through with actionable items. The Company did undertake significant outreach efforts in 2020 with digital and radio ads, outbound calls, emails, and letters to inform customers of available assistance programs and payment plan options. As explained prior in this rebuttal testimony, the Company is also proposing an outreach campaign to assist customers affected by the Pandemic to take advantage of available resources and Company programs.

Q. Please summarize Mr. Colton's recommendation to reduce the USP rider to reflect a reduction of administrative costs in 2020

A. Mr. Colton testifies that administrative costs incurred in 2020 should be lower than prior years. He bases his conclusions on the reduction of activity that occurred in 2020.

Q. Is Mr. Colton's assessment accurate?

A. No. Mr. Colton is correct in stating less customers re-verified income, enrolled in programs and called the contact center. However, the administrative charges are largely fixed monthly fees. The CAP administrator charges a fixed monthly fee to provide the services of oversight of the program. This includes, answering phone calls, training and updating community based agencies, verifying income, and updating the Company billing system among other responsibilities. This charge did not change in 2020 even with less activity because these services were still being performed.

Costs related to the Company call center also did not decrease in 2020. Although the Company's call center received fewer inbound calls than in years past, Customer

Service Representatives made outbound calls to all customers that were in arrears to explain programs including LIHEAP and CAP.

The USP rider reflects incurred costs that are trued up on a yearly basis. In this case, in April of 2021.

Q. Does this conclude your testimony related to Mr. Colton's testimony?

A. Yes.

Q. What issues will you address regarding Mr. Geller's testimony?

A. I will address the following recommendations:

- To reduce the CAP energy burden to 4 and 6%;
- Increase the LIURP Health and Safety pilot budget,
- Develop multi lingual programs materials; and
- Refunding security deposits to low income customers and changing tariff language.

Q. Please address Mr. Geller's recommendation to reduce the CAP energy burden to 4 and 6%

A. The Company continues to hold the position that it should not change its CAP payment plan structures without considering the impact of and changes on other control features. Columbia currently has the lowest average CAP Payment plan of all Pennsylvania utilities. It has calculated the cost of reducing the percent of income plan to 4% and 6% without any other changes to be more than $1 million annually, and that number will increase with an increase in participation.

Q. Please explain what control features should be considered should be

evaluated prior to changing the CAP payment plan structure?

A. Factors such as usage, maximum CAP credits, minimum payments and other available resources should be reviewed as part of any program design changes. For instance, Columbia does not remove customers or raise payments if or when a customer exceeds a standard maximum CAP credit. Instead, Columbia provides LIURP benefits, or if LIURP was already received, remedial energy education to customers who continue to have high usage. The Company recognizes that in many cases the usage is beyond a customer's control and, therefore, the customer should continue to receive an affordable payment plan even if their CAP credits are higher than other customers or exceed a standardized threshold. Another utility may agree to reduce a customer to four and six percent of income, but if that utility has a maximum CAP credit as part of its CAP design, the utility will continue to remove customers from CAP or raise their payment the month the customer goes over the maximum CAP credit. Thus, in effect, those customers are not provided with a year round four and six percent payment plan. These nuances become critical to truly addressing and understanding the affordability of any CAP payment plan, and no single design aspect should be changed without reviewing the other design factors.

In response to data request CAUSE PA 1-4 (Exhibit DD-2R), Mr. Geller stated that there was no need for additional control features than those already in place, seemingly accepting that the $1 million in increased cost was reasonable for non-CAP customers to absorb and offering no recommendations on balancing the needs of all residential ratepayers.

Q. Please summarize the existing energy burdens for the Company's CAP customers.

A. The chart below provides the energy burden based on February 2021 billing and the most recently reported income. The chart provides the energy burden average by overall (i.e., all CAP customers), FPIG % and Payment Option, along with the number of customers in that subset.

	Energy Burden	# of Customers
Zero Income		1,150
Customers not reporting zero income but on minimum		1,299
Overall Average	4.63%	20,746
0 - 50%	6.75%	3,129
51-100	4.99%	10,305
101-150	3.25%	7,312
Option #1	7.30%	4,382
Option #2	3.86%	2,169
Option #3	3.94%	14,560

The chart demonstrates that the vast majority of customers are already being asked to pay less than 6%. The 0 – 50% of FPIG is asked to pay on average 6.75% of their income for their natural gas service. However, the asked to pay percentage does not take into account the fact that this group of customers can seek the assistance of LIHEAP or CRISIS. All of these customers are eligible for LIHEAP or CRISIS. At their reported income, they would receive more than the minimum payment of

$200. However, assuming they only received the minimum LIHEAP grant and no CRISIS grant, their asked to pay drops to 4% of their income (the average payment drops from $46.00 a month to $29.00 a month). Therefore, if the customer receives LIHEAP or CRISIS, the payment plan would be less than the 4% or 6% energy burden. This does not even account for the numbers of customers who receive utility assistance from other entities including housing authorities that are not counted as income but must be used to pay utility bills.

Q. Why do you think LIHEAP should be considered when establishing payment plan design?

A. LIHEAP is funded by the federal government to assist low income households in meeting their immediate home energy needs. Currently in Pennsylvania, the minimum grant is $200, but can be as high as $1,000 depending on income, family size and fuel type. DHS has filed a proposed plan to raise the minimum to $300 for the 2022 program year.

Although LIHEAP cannot be counted towards income or used as resource for other programs, The *Home Energy Affordability for Low-Income Customers in Pennsylvania* (Report), at Docket No. M-2017-2587711, a study conducted by the Commission, states on page 42, "LIHEAP had a measurable impact on energy burdens for CAP customers. After applying LIHEAP, CAP customers with incomes at or below 50% FPIG level experienced an energy burden decrease of approximately 5 to 6 percentage points for gas heating."

Recognizing the impact that LIHEAP grants have on reducing customer payments for utility service, the Commission ordered Columbia to "encourage its customers to apply for LIHEAP at every opportunity" in its USECP order (page 13). As such, CAP payment plans should be designed with recognition that LIHEAP is also available and can reduce energy burdens by as much as 6 percentage points for the 0 – 50% of FPIG tier. To design a CAP program without leveraging available federal grant dollars unfairly burdens the other residential customers funding the program.

Q. How does usage play a role in determining payment plan options?

A. The Company calculates a payment plan based on 50% of the annual budget as one of three options to select a CAP payment plan. The three CAP payment options are (1) 7% and 9% of income ("percent of income plan"), (2) average of payments in the year prior to joining CAP and (3) 50% of the promoted budget. The percent of income plan is often chosen when the percent of budget is higher than the percent of income plan. Many customers on percent of income plans have significant usage which would make the 50% of budget plan unaffordable, therefore the percent of income plan was selected for the customer. Therefore, non-cap customers are subsidizing a much higher portion of these customer's bills than customers on Option 3. Without adding maximum CAP credits, reducing the energy burden will only increase the percentage of the bill non-cap customers have to subsidize.

Q. How does high usage impact the costs to residential customers not enrolled in the CAP program?

A. Residential customers pay the difference between a CAP customers full bill and the amount a CAP customer is asked to pay (this difference is known as the CAP shortfall). This means that if the Company moves from using 7 and 9 percent of income down to 4 and 6 percent of income, there would be a significant increase to the Company's CAP shortfall, since many of these customers have high usage. Mr. Geller points out that customers would only have to pay between $2.84 and $2.89 per year to cover the cost of this program design change. However, that figure is based on current gas costs, current rates, and current participation rates. Any increase in any of those factors will increase the subsidy. It is also important to note that a customer who is only over by $1.00 of the annual 150% of FPIG will be ineligible for CAP and LIHEAP, but required to pay their full bill plus the additional $.24 per month to assist CAP customers. Further, increasing the CAP shortfall is unnecessary when CAP customers can use federal funds to reduce their payment even further.

Q. Please summarize Mr. Geller's recommendation on the LIURP Health and Safety Pilot.

A. Mr. Geller is recommending an increase of the Health & Safety Pilot from $200,000 to $600,000 annually and an extension of the program beyond its current end date of 2022.

Q. Please provide an update of the current Health & Safety Pilot.

A. The Company was scheduled to begin the Health & Safety ("H & S") pilot upon approval in 2020. When the COVID-19 pandemic ceased all in home LIURP activity, the H & S pilot was also suspended. When work was able to resume, the first step involved identifying potentially eligible homes. The Company reviewed past deferred jobs as well as current jobs for eligibility. The Company has recognized that its USECP approved model works well for those customers with extremely high usage, more than 3000 therms annually. Only a small percentage of customers meet that usage threshold and all of these properties have been reviewed. The difficulty is the model's allowance for H & S. Though more than traditional H & S allowance, it is still too low to address the primary obstacle to weatherization. Often times, an entire roof needs replaced, not just a patch. Mold or mildew needs remediated and then the source of water needs remedied. This can cost between $10,000 and $20,000, which is higher than the model allows in most cases.

Q. How many homes have been completed to date?

A. Unfortunately, the Company only has three homes in progress and no completions. The Company continues to review records to find more homes; however, it is unlikely the Company will meet its goals under the current model. The experience of the Company demonstrates this pilot is very time consuming, requiring a lot of research of contractors, visits to the homes and oversight. The Company has identified over ten homes that qualify, but after weeks of review and contractor appointments, most were deemed too costly and outside the model scope.

Q. Do you support the concept of a Health & Safety Pilot?

A. Yes. For all the reasons Columbia initially proposed the pilot, the Company still supports the effort. However, Columbia recognizes that the model needs adjusted to increase the number of customers that can be assisted. The Company has done some analysis and believes adjusting the model to recognize savings that can be realized through a reduction of shortfall would increase the Health & Safety allowance providing for homes with lower usage to have an allowance that would be sufficient to remediate the reason for the deferral.

Q. If these adjustments can be made, would the Company support an increase to $600,000?

A. The Company currently has a LIURP budget over $7 million due to a large carryover in 2020. In addition, due to staffing shortages and a lack of customer engagement the Company will have a large carryover this year as well. The Company would support increasing the allotment from the overall LIURP pool to the Health & Safety pilot to $400,000 and extending the program out through the end of 2023 if these adjustments can be made. The Company would also agree to raise the allotment to $600,000 in 2023 if homes are identified and the pilot is proving successful in 2022.

Q. Please summarize Mr. Geller's recommendation on multilingual communications.

A. Mr. Geller is recommending the Company develop universal service outreach materials including bill inserts, which will inform customers of the existing translation services available on its website.

Q. Do you agree with Mr. Geller's recommendations?

A. The Company is not opposed to adding a brief statement to Universal Service materials to explain the translation services available on the Company's website, as the need for re-printing of a particular document becomes necessary. Currently, there is an existing supply of materials already produced for the upcoming heating season that would need to be used first. However, the Company agrees this information will be helpful to a small group of customers going forward and will endeavor to add the information over time. In addition, the Company is researching the cost to track what languages are requested on the interpreter line for Pennsylvania customers only.

Q. Please summarize Mr. Geller's recommendations regarding security deposits.

A. Mr. Geller is recommending several items related to security deposits. He recommends that the Company refund deposits associated with a low income customer that is currently being retained by the Company, that the Company review accounts on a regular basis to refund any deposits charged to low income customers, and that the Company revise its tariff pages to reflect all customers confirmed to be CAP eligible will not be charged a deposit.

Q. Please clarify the Company's current security deposit policy.

A. At the time a customer calls to establish service, the customer's credit score and any previous accounts will be reviewed to determine if a security deposit will be required. However, if at any point during the call the customer reports income at or below 150% of the FPIG, the Company will waive the requirement based on the self-declared income. If the Company charges a customer a security deposit and later determines the customer is low income by either receipt of LIHEAP funds or CAP enrollment, the Company will refund to the account any deposit that was previously paid.

The Company also contracts with a third party to administer its Security Deposit Assistance Fund (SDAF) for customers between 151% and 250% of FPIG. Customers can complete the application process with the administrator who will authorize a benefit to assistance with the security deposit. This fund has been in existence since 2009 and has remained available to all eligible customers without interruption. The program, which costs up to$50,000 per year, is paid for by the Company's shareholders.

Q. If the Company waives deposits for level one customers, why are some deposits attributed to level one customers?

A. It is possible a customer does not claim income below 150% of the FPIG when they connect service and pay a security deposit but subsequently call in and self- declare income below 150% of the FPIG. At that time, the customer is referred to CAP. If they follow through with CAP and confirm they are CAP eligible, their security deposit will be refunded at that time.

Q. Do you agree with Mr. Geller's testimony that the Company is not in compliance with regulations?

A. No. Mr. Geller cites the regulation in his testimony that states the applicant needs to be confirmed to be eligible by providing income documents. The emphasis is on confirmed. A customer that does not provide income information is not confirmed to be eligible. Therefore, the Company's policy is in line with the regulation.

Q. On page 34 of CAUSE-PA's direct testimony, Statement 1, Mr. Geller raises concerns that the Company's current tariff does not specifically address the fact that security deposits are not required for CAP eligible customers – that all customers confirmed to be income eligible for CAP will not be charged a security deposit, regardless of whether the household subsequently enrolls in CAP. Do you agree?

A. Yes. On the Tenth Revised Page No. 140 of the Company's current tariff, and also referenced in Mr. Geller's testimony, the Security Deposit section indicates that "CAP customers will not be charged security deposits". Per the Public Utility Code and Commission regulations, the Company agrees that the language should be revised to read that "CAP eligible customers will not be charged security deposits".

Q. Is there a reference in the Company's current tariff that references that security deposits would be waived for CAP eligible customers?

A. Yes. On the Ninth Revised Page No. 44 of the Company's current tariff, the Deposits section does specifically address that "A customer or Applicant who is confirmed to be eligible for the Customer Assistance Program shall not be asked to provide a cash deposit".

Q. Despite the language in the tariff on the Tenth Revised Page No. 140 only indicating that CAP customers will not be charged a security deposit, is the Company following all of the regulations around CAP eligible customers and security deposits?

A. Yes.

Q. Are you proposing changes to the Company's current tariff to address Mr. Geller's concern?

A. Yes. The Company is proposing to add the word 'eligible' within the Security Deposits section of the current tariff on the Tenth Revised Page No. 140. The new sentence will read: CAP eligible customers will not be charged security deposits.

Q. Do you agree with Mr. Geller's recommendation to refund security deposits and regularly scan future deposits to refund them?

A. No. The Company follows Commission guidelines for refunding security deposits to customers including when a customer confirms they are eligible for CAP.

Q. Are there any other issues you wish to address in Mr. Geller's

testimony?

A. No.

Q. What issues will you address regarding Mr. Brady's testimony?

A. I will address the recommendation for additional COVID-19 assistance similar to UGI's Emergency Relief Program ("ERP"), increases to the budgets for LIURP and Hardship Fund, and the recommendation to partner with PWPTF member agencies.

Q. Do you believe additional assistance such as UGI's ERP program is necessary?

A. First, I note that OCA witness Colton made a similar recommendation regarding Columbia implementing an ERP-like program, and my response to Mr. Brady's applies to Mr. Colton's recommendation as well. It is the Company's position that an additional assistance program is not necessary at this time. As explained earlier in my rebuttal testimony and in my direct testimony, there are ample resources available to assist customers, including the Company's Hardship Fund, which was expanded in 2020 to assist customers financially impacted by COVID-19.

Q. Do you believe there is a need for additional funds for LIURP?

A. Due to a large carryover in 2020, the Company's 2021 budget is $7.3 Million. As of June 1, 2021 the Company has spent roughly $900,000. The Company continues to struggle to find cooperative customers who agree to have their home weatherized. In addition, contractors report staffing shortages and other priorities creating production slowdowns. In response to Data request PWPTF 1-4, Mr. Brady acknowledged that he is aware of workforce shortages that may have hindered production. The Company is planning a promotion in the fall of this year to encourage energy efficiency; however, the Company believes it will again have a large carry over balance. At this time, increasing LIURP does not make sense. The Company contractors will not be able to spend the money, which results in the Company having a surplus of ratepayer funds from Rider USP.

Q. Does the Company support Mr. Brady's recommendation to partner with member agencies?

A. As stated prior, the Company is struggling to spend its budget. If there are contractors already doing weatherization that have the capacity to do more work in the counties that Columbia serves, the Company would welcome the partnership so long as the organization can do enough homes to warrant the training. However, in response to data request PWPTF I-3, Mr. Brady did not identify any specific member agencies and the Company is unaware of any member agencies not currently in partnership with the Company in counties where a need exists.

Q. Does the Company support increasing its Hardship Fund Budget?

A. At this time there is no need to increase the Hardship Fund. The Company expects to carry over funds into the next program year. In addition, the next program year will have a minimum of $675,000 in addition to funds carried over. The LIHEAP program has significant dollars to spend between now and August 2022 and the

Company is aware of other COVID-19 relief funding that will be made available in the future as well.

Q. Does the Company support Mr. Brady's recommendation to allocate funds to specific geographical areas?

A. The Company recognizes the value of such allocations when funds are scarce and there is a possibility due to administrative inconsistencies that some areas may not be able to access funds as quickly as others. If funds were scarce, there would be a value to geographical allocations. However, the Company currently has ample funds and no customers have been turned away in several years for lack of funds. Therefore, the risk to geographical allocations is that money will be unspent in some areas, while a need exists in others. For these reasons, the Company does not support geographical allocations.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

OCA-II-8. Please provide a copy of any comments filed in response to the 2021 fiscal year LIHEAP proposed state plan and please forward any copy of comments filed for the 2022 fiscal year LIHEAP proposed state plan when complete.

Answer:

The Office of Consumer Advocate did not file comments in response to the FY 2021 LIHEAP State Plan. The Office of Consumer Advocate does not anticipate that it will file comments to the FY 2022 LIHEAP State Plan.

Prepared by: Christy Appleby
Dated: 07/06/21

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2021-3024296
Data Requests for CAUSE-PA

CAUSE-PA-I-4. What control features would CAUSE-PA recommend to coincide with a reduction in energy burden to 4 and 6%?

Response: CAUSE-PA asserts that there are already Commission approved control features within Columbia's CAP. Adoption of reduced energy burden standards would not require additional control features.

Respondent: Harry Geller

Date: July 1, 2021

COLUMBIA STATEMENT NO. 13-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

SURREBUTTAL TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 27, 2021

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. Have you previously filed Direct and Rebuttal testimony in this matter?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to the rebuttal testimony served in this proceeding by Mr. John Zalesky representing the Bureau of Investigation and Enforcement. Specifically, I will respond to Mr. Zalesky's recommendations regarding the Emergency Relief Program ("ERP") proposed by the Office of Consumer Advocate's ("OCA") witness, Mr. Roger Colton.

Q. What did Mr. Zalesky recommend regarding the OCA's ERP proposal?

A. Mr. Zalesky recommended that the proposal for an ERP be denied because it is not needed. However, Mr. Zalesky also stated that if the Commission were to approve an ERP, the ERP should be "fully funded by shareholders as opposed to the Company's ratepayers." I&E St. No. 1-R, p. 6.

Q. Do you agree with Mr. Zalesky that an ERP is not necessary?

A. Yes. As stated in my rebuttal testimony, there is ample funding available to assist customers with their delinquent gas bills. The Company has experienced a lack of engagement from customers to apply for these funds, and therefore has recommended a multi-faceted outreach campaign to help link customers to available resources.

Q. Do you agree with Mr. Zalesky's recommendation that any ERP program approved by the Commission be funded by shareholder dollars?

A. No. Company shareholders currently voluntarily contribute $150,000 to the Hardship Fund to match customer donations. In addition, shareholders voluntarily contribute up to $50,000 yearly to fund the Company's Security Deposit Assistance Fund. In 2020, shareholders did contribute $400,000 to support the expansion of the Hardship Fund income guidelines up to 300% of the Federal Poverty Income Guidelines. These funds represent the majority of donations made to all organizations from the Company's shareholders. Finally, I have been advised by legal counsel that if the donation of additional shareholder dollars were the result of a Commission directive, the Company would have a right to seek full recovery of those dollars

Q. Does this complete your prepared surrebuttal testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 13-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

REJOINDER TESTIMONY OF
DEBORAH DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2021

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. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your Rejoinder testimony?

A. I will respond to the testimony served in this proceeding by Mr. Roger Colton representing the Office of Consumer Advocate related to a recommendation to reduce CAP administrative costs for 2020 and available COVID-19 relief funding.

Q. Mr. Colton recommends the Company reduce its USP Rider charge for 2020 to reflect reduced CAP administrative charges in 2020. What issues related to this will you be clarifying in this testimony?

A. In surrebuttal testimony beginning on page 20, Mr. Colton suggests that costs associated with outreach for the CAP program are not part of Universal Service administration. He further states that CAP administrative costs are not fixed costs and suggests a decline in enrollment and reverification activity should equate to a reduction in administrative costs.

Q. Please address why outreach activities such as outbound calling should be considered part of Universal Service Administration.

A. The Commission recently recommended as part of the revised CAP policy statement that all Universal Service and Energy Conservation Plans should incorporate a consumer education and outreach plan. Various strategies and methods of outreach are considered including outbound calls. Outbound calls confirm eligibility for programs and start the application process when the customer agrees.

Q. Please address Mr. Colton's statement that CAP administrative costs are not fixed costs as it relates to its call center.

A. The Company staffs its call center to meet historic demand. It was not possible to project what activities would occur that would impact call volume as the pandemic extended into the summer, fall and winter. Likewise, it was not possible to staff down during the time period that COVID-19 stay at home orders were in effect and expect that staffing would be available when the situation changed. These fixed costs were unavoidable. The Company took steps to use existing resources wisely including outbound calls to refer to the open LIHEAP and CAP programs.

Q. Please clarify the activities that continued to occur in 2020 even as enrollment and reverification decreased.

A. The Company continued to promote CAP, process enrollments and verify income. The Company sent letters to all customers that needed to verify income in the same manner as prior to the pandemic including an initial and a reminder notice. Though the Company did stop the process at the point a customer would be removed from CAP, reverification of income still occurred.

Q. Please explain why CAP administrative costs did not largely drop when applications declined.

A. The Company's contract with its administrator includes full time staffing solely dedicated to taking calls and applications from customers. The Company transfers interested customers from its call center directly to the administrator's call group for application processing. Several years ago, the Company was able to negotiate a lower application rate by staffing full time employees rather than pay a per application fee for applications taken over the phone by this call team. Historically, this has resulted in a savings in administrative costs. However, due to the Pandemic in 2020, this created a need to maintain staffing even though there was a drop in activity. The Company did see a drop in application fees related to community based agencies since agencies paid on a per application basis were not taking as many applications. Because the CAP Rider is reconciled, reductions in these application fees were reflected in CAP costs.

Q. Please summarize why the Company's CAP administrative costs are largely fixed costs.

A. The Company's CAP administration includes permanent full time staffing at its call center as well as its administrator for the purposes of responding to customer questions, making referrals and taking applications. In addition, administrative fees include staffing to process applications and verify income. All of the costs associated with these activities are staff related and therefore fixed costs. The variable costs are associated with agency fees for applications taken which is paid as a per application fee. Using Mr. Colton's chart found on page 63 of direct testimony, the categories of Labor, Outside Services, and Call Center Costs are fixed costs. In addition, a portion of the application fees are fixed costs. Please note that Labor represents internal staffing and is not recovered through Rider USP.

Q. Mr. Colton explains that the resources available are not substantial enough to negate the need for an additional emergency relief fund. Can you clarify the funds that are available to Columbia Gas customers?

A. Yes. The chart below illustrates the resources that are known at this time. The available funding is the total pool of funds available for all components of the program for all eligible customers including non- utility assistance as defined by each program. The average grant identifies the current average grant received by Columbia Gas customers. I note that LIHEAP and the Homeowner Assistance Fund are projected to open in the Fall, 2021.

Program	Available Funding	Eligibility Guidelines	Average Grant	Maximum
Emergency Rental Assistance Program	$564,000,000	*80% of Median Income *Renters only	$862	all arrears accrued since April, 2020
Community Development Block Grant	$1,000,000	*80% of Median Income *Homeowners only *Allegheny County resident not within Pittsburgh city limits	$438	
Low Income Home Energy Assistance (CASH)		< or =150% FPIG	Unknown	$1,500
Low Income Home Energy Assistance (CRISIS)	$337,500,000	< or =150% FPIG	Unknown	$1,200
Homeowner Assistance Fund	$350,000,000	Homeowners only	Unknown	all arrears accrued since April, 2020
Columbia Gas Hardship Fund	$1,125,000	*300% of poverty until 9/30/21 *200% of Poverty (10/1/21 - 9/30/22)	$300	$500

This chart illustrates the significant funds that are and will be available to assist customers with utility arrears and will provide adequate relief without the need for an additional emergency relief program.

Q. Does this complete your Prepared Rejoinder Testimony?

A. Yes, it does.

C. ANSTEAD

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
C.J. ANSTEAD ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. C.J. Anstead, 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 the Vice President of Gas Operations.

Q. What are your responsibilities as Vice President of Gas Operations?

A. My responsibilities include overseeing:

- Delivery of safe and reliable natural gas distribution service to our customers;
- Leak detection, leak investigation, leak response and leak repair activities;
- Customer metering activities;
- Plant operations and system regulation;
- All required leakage surveys and system inspections, testing and inspection of cathodic protection systems for steel facilities, and performing underground facilities locating for third-party excavators;
- The day-to-day operations of Columbia's physical natural gas piping system; and

- Field customer service to Columbia customers including: odor complaints, meter turn-ons and turn offs, and all other customer interfacing field interactions.

Q. Please briefly describe your professional experience?

A. I have over thirty years of experience in the natural gas industry with a large focus, primarily in gas operations and construction. Prior to joining Columbia in 1998, I worked for a natural gas pipeline contractor. During my tenure at Columbia, I have worked in a variety of roles across the NiSource companies and within NiSource Corporate Services in field activity based roles and manager level roles. Most recently, I served as the Director of Technical Services for NiSource Corporate Services from May of 2017 through June of 2019 where I was responsible for the quality assurance and operator qualifications programs across the NiSource companies. In June of 2019, I moved into the role of Director of Safety, Compliance and Risk Management for Columbia Gas of Ohio, where I was responsible for initiatives to address risk and improve safety. I will transition into the Vice President of Gas Operations role for Columbia Gas of Pennsylvania on April 1, 2021.

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

A. No.

Q. Please describe your membership in, or affiliation with, any industry organizations.

A. I have been a member of the American Gas Association Quality Management

Committee since March of 2017.

Q. What is the purpose of your direct testimony?

A. I will provide an overview of Columbia's distribution system. 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 Distribution Integrity Management Program ("DIMP"), the strategic operation and maintenance ("O&M") activities that it has undertaken to improve its system, and the additional O&M activities that Columbia is planning to undertake.

II. Overview of Columbia's Pipeline Distribution System

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves approximately 436,000 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 7,737 miles of distribution and transmission mains and approximately 435,106 services that it owns, operates, and maintains.[1] These facilities (as of January 1, 2021) are composed of

[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

approximately 1,046 miles of bare steel, 23 miles of cathodically protected bare steel, 4 miles of cast iron, 54 miles of wrought iron mains (in total, 1,127 miles of "first generation priority pipe" main), and 40,456 bare steel services.[2] The balance of the system is comprised of cathodically protected coated steel (some of which is pre-1971 coasted steel), or plastic (some of which is pre-1982 plastic) mains and services, and 26.8 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")

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the service line to the building.

[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 26.8 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 2012.

to the natural gas before it is put into the distribution system. The gas then goes into the distribution system where the pressure is often further reduced to delivery pressure in a series of district regulator stations, before being delivered to each customer. Once the gas is delivered on the customer's side (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 initial 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 to slow the inevitable deterioration process. 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. Coated steel pipe continues to be used, but it is cathodically protected with an electric current. Further, since that time Columbia has retrofitted all of its unprotected coated steel facilities with cathodic protection systems.

Q. **What is the outlook for UPCS pipe?**

A. Since Columbia installed the last miles of UPCS in 1970, that pipe is reaching the end of its useful life just by the passage of time and the inevitable resulting corrosion. In addition, however, even though that pipe was coated to protect against corrosion, some of that pipe is now being found to have been ineffectively coated. Ineffectively coated steel pipe refers to coated steel pipe that may have inadequate, field-applied coatings. Columbia continues to perform all routine monitoring and inspecting activities to ensure that this type of coated steel pipe will continue to operate safely, however, Columbia has a long-term concern that field-applied coatings used primarily on steel pipe prior to 1955 - and intermittently between 1955 to 1970 - have or will become ineffective over time. As this occurs, these coated steel lines demonstrate the leakage characteristics of our bare steel pipe. In the interest of safety and reliability, Columbia has been replacing many sections of coated steel main installed prior to 1971 as it is encountered in association with a bare steel or cast iron replacement project. Columbia first inspects the pipeline coating for damage (e.g., scrapes, gouges), deterioration, or disbonding (e.g. cracking, blistering, chipping, flaking, or loose) and completes a field analysis to assess the cathodic protection current requirements of the pipe. To the extent that these analyses identify segments of protected steel pipe that are ineffectively coated, Columbia replaces that pipe as part of its bare steel or cast iron replacement.

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. In addition, 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 also known as "Pre-1982 Plastic", typically installed between mid to late 1960s and 1981 in most distribution systems and more brittle than today's material (due to the different composition of the base plastic material), has demonstrated itself to be prone to stress propagation cracking under some circumstances. In a special investigation report completed by the National Transportation Safety Board on April 23, 1998, it concluded that between the 1960s through the early 1980s, the procedure used in the United States by manufacturers to rate the strength of this plastic pipe may have overrated the strength and resistance to brittle-like cracking. The investigation performed further clarified that such first-generation plastic pipe was susceptible to premature brittle-like failures when subjected to stress intensification and as a result represented

a potential safety hazard. Given the safety concerns that arise when this pipe is subjected to stress intensification, the most efficient course of action has been for Columbia to replace Pre-1982 pipe when it is encountered in association with a pipeline replacement project. This eliminates the need to induce stress on the first-generation plastic pipe during the standard squeeze-off operation performed to control or stop gas flow when preparing to reuse and reconnect existing first generation plastic pipe to newly installed plastic pipe, and it eliminates the risk of the pipe cracking due earth movement or other forces. As this Pre-1982 pipe continues to age, the risk of it developing Type 1 leaks continues to grow and will need to be replaced even when it is not associated with a bare steel or cast iron replacement program. 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. Regarding excavation damage, Columbia has made significant progress in reducing facility damage rates. In 2007, damages per thousand locates were at 5.39. By 2020, Columbia was able to reduce the damages per thousand locate tickets to 2.05. Locate ticket volumes were down 6% last year. Total number of damage reduced from 287 in 2019 to 278 in 2020. Efforts to improve locator performance and improved techniques for finding difficult to locate facilities have proven to be effective.

Excavator negligence remains the highest cause of damages to our facilities, at 57% of total damages in 2019. Columbia continued to intervene and educate excavators – especially the problematic ones – and was able to achieve a 7% reduction to excavator error between 2019 and 2020. Columbia adopted a "Damage Prevention Risk Model" to guide its outreach to the riskiest excavators. 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.

Columbia continues to deploy global positioning system ("GPS") mapping and locating technology that provide sub-decimeter accuracy in identifying the location of new or replacement facilities. This technology will enable the Company to accurately locate its new facilities in the field.

In order to address the issues discussed above with Pre-1971 coated steel pipe and Pre-1982 plastic pipe, Columbia is replacing those sections which are uncovered in the course of executing the bare steel and cast iron replacement program Additionally, 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.

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."

III. 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:

- Integrity Management Program for Gas Distribution Pipelines (74 FR 63906) - This final rule amended 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. Distribution integrity management is playing a significant role in Columbia's gas operations, allowing us to focus resources to reduce risks, thereby improving safety for our customers, the public, and our employees.

- Safety of Underground Natural Gas Storage Facilities (85 FR 8164 supersedes 81 FR 91860) – Pursuant to Section 12 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" or the "PIPES Act of 2016", this Federal Department of Transportation final rule ("FR") amends the Federal pipeline safety regulations to establish minimum federal safety standards for underground natural gas storage, including critical safety issues related to downhole facilities--well integrity, wellbore tubing, and casing. The FR incorporates the American Petroleum Institute's ("API") recommended practice 1171 by reference into the pipeline safety regulations. This recommended practice outlines the standard for the functional integrity of natural gas storage in depleted hydrocarbon reservoirs and aquifer reservoirs. Incorporating these recommendations will provide the Pipeline and Hazardous Materials Administration ("PHMSA") and the states with a minimum federal standard for inspection, enforcement, and training through a federal/state partnership and certification process modeled after the current pipeline safety program. The FR applies to Columbia's Blackhawk underground storage facility located at 115 Felt Lane, Beaver Falls, Pennsylvania. While fulfilling its obligations under this Final Rule, Columbia conducted casing integrity logs on its Blackhawk wells during 2020. The results of the casing integrity logs revealed casing deterioration damage on the top joint of the production casing on two of the wells. To perform the necessary repairs, Columbia safely isolated the wells. Impacted joints were then safely replaced, the plugs removed, and the wells were brought back into service. As part of API 1171, Columbia will continue to manage and maintain protocols associated with the safe operations of the wells. This is a great example of how recommended practices, Integrity Management Programs and SMS identify and bring to light latent risks so that they may be prioritized to protect the distribution system, customers, the communities and employees.

- <u>Pipeline Safety:</u> Gas Pipeline Regulatory Reform (86 FR 2210) PHMSA is amending the Federal Pipeline Safety Regulations (PSR) at 49 CFR parts 191 and 192 to ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering pipeline systems without adversely affecting safety. These amendments include regulatory relief actions identified by internal agency review, petitions for rulemaking, and public comments submitted in response to a Department of Transportation (DOT) regulatory reform notice entitled "Notification of Regulatory Review." Specifically, the changes to the regulations that can impact the Company include the following:

- Amending the definition of an incident (§191.3) by increasing the cost of property damage from $50,000 or more to $122,000 or more. The rule also gives PHMSA the ability to adjust the reporting threshold based on inflation and posted on PHMSA's website.
- Removes the requirement to report mechanical fitting failures by removing §191.12 Distribution Systems: Mechanical Fitting Failure Reports and §192.1009 What must an operator report when a mechanical fitting fails. However, PHMSA is revising the Gas Distribution Annual report form (PHMSA Form F 7100.1-1) to identify the number of leaks involving a mechanical joint failure as a separate line item from the count of leaks by cause.
- Giving the Company the choice of managing inspections of pressure regulators serving farm taps under its distribution integrity management plan (DIMP) (§192.740 Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to production, gathering, or transmission pipelines).

- Revision of § 192.465, External corrosion control: Monitoring, to clarify that operators may remotely inspect rectifier stations for external corrosion.
- Revision of the welding process requirement at § 192.229, Limitations on welders and welding operators, to align better with welder requalification requirement to specify that welders or welding operators may not weld with a particular welding process unless they have engaged in welding with that process within the preceding 7½ months. This change would provide operators some flexibility in scheduling welding activities to maintain welder requalification.
- Revision of atmospheric corrosion monitoring requirements (at §§ 192.481, 192.491, 192.1007, and 192.1015) both to align the inspection interval for atmospheric corrosion on gas distribution service pipelines with leakage survey requirements at § 192.723, and to clarify that consideration of corrosion risks under DIMP explicitly includes atmospheric corrosion.
- Revision of requirements governing plastic pipe (at §§ 192.7, 192.121, 192.281, 192.285, and appendix B to part 192) to improve alignment with, and incorporate by reference, certain updated industry standards.

    - Revision of test requirements for pressure vessels at § 192.153 to align pressure test factor requirements with industry standards, and to clarify certain other pressure testing requirements.
    - Revision of language at § 192.507 to extend an existing authorization for pretesting of fabricated units and short segments of steel pipe prior to installation on pipelines with high-stress operating conditions to pipelines operating at lower-stress operating conditions.
- <u>Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments</u> (84 FR 52180) – Pursuant to National Transportation Safety Board ("NTSB") recommendations and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA has promulgated regulations governing the safety of gas transmission pipelines. The purpose of this final rule is to increase the level of safety associated with the transportation of gas. This rule requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the maximum allowable operating pressure ("MAOP") of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. This includes previously untested pipelines, which are commonly referred to as "grandfathered" pipelines, operating at or above 30 percent of specified minimum yield strength

("SMYS"). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location. Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created a framework whereby operators with insufficient material property records can obtain such records. PHMSA considers "insufficient" material property records to be those records where the pipeline's physical material properties and attributes are not documented in traceable, verifiable, and complete records. PHMSA is requiring operators to perform integrity assessments on certain pipelines outside of high consequence areas ("HCAs"), whereas prior to this rule's publication, integrity assessments were only required for pipelines in HCAs. Pipelines in Class 3 locations, Class 4 locations, and in the newly defined moderate consequence areas ("MCAs") must be assessed initially within 14 years of this rule's publication date and then must be reassessed at least once every 10 years thereafter. These assessments will provide important information to operators about the conditions of their pipelines, including the existence of internal and external corrosion and other anomalies, and will provide an elevated level of safety for the populations in MCAs while continuing to allow operators to prioritize the safety of HCAs.

This action fulfills the section 5 mandate from the 2011 Pipeline Safety Act to expand elements of the IM requirements beyond HCAs where appropriate.

- Pipeline Safety: Inside Meters and Regulators, issuance of advisory bulletin ADB-2020-01 (85 FR 61101) - To further enhance PHMSA's safety efforts and implement NTSB's April 24, 2019, Recommendations P–19–001 and P–19–002, PHMSA issued this advisory bulletin to remind operators of the requirements for inside meters and regulators and of the existing Federal DIMP regulations to reduce the possibility of the failure of inside meter and regulator installations. NTSB Recommendations to the Pipeline and Hazardous Materials Safety Administration:
    - P-19-001: Require that all new service regulators be installed outside occupied structures.
    - P-19-002: Require existing interior service regulators be relocated outside occupied structures whenever the gas service line, meter, or regulator is replaced. In addition, multifamily structures should be prioritized over single-family dwellings.

PHMSA is alerting owners and operators of natural gas distribution pipelines to the consequences of failures of inside meters and regulators and existing Federal regulations covering the installation and maintenance of inside meter and regulators. PHMSA is also reminding operators of their obligation to continually assess risks to their systems and address those risks as required by the DIMP regulations (§ 192.1007). PHMSA reminds pipeline operators of their responsibilities to continuously improve their knowledge of their pipeline systems, identify integrity threats, evaluate and rank risks, and identify, evaluate, and implement preventative and mitigative measures as required by the Federal Pipeline Safety Regulations.

- Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems, issuance of advisory bulletin ADB-2020-02 (85 FR 61101) - PHMSA is reminding all owners and operators of low-pressure natural gas distribution systems of the risk of failure of overpressure protection systems. Advisory bulletin ADB-2020-02 is intended to clarify the existing pipeline safety standards and highlight the importance of evaluating and implementing overpressure protection design elements and operational practices within their compliance programs. This advisory reminds pipeline operators of their obligations to comply with the gas DIMP regulations at 49 CFR part 192, subpart P. Under DIMP, gas distribution operators must have knowledge of their pipeline systems; identify threats to their systems; evaluate and rank risks; and identify, evaluate, and implement measures to address those risks. ADB-2020-02 highlights the need for operators of low-pressure systems to review thoroughly their current DIMP for the threat of overpressurization and to make any necessary changes or modifications to become fully compliant with the Federal Pipeline Safety Regulations (§192.1007(f)).

In addition to the FRs and Advisories above, the following proposed rules or recommendations are currently being made by, or are under consideration by PHMSA:

- Valve Installation and Minimum Rupture Detection Standards (PHMSA-2013-0255 RIN 2137-AF06) - PHMSA has issued a notice of proposed rulemaking ("NPRM") proposing regulations for: the installation of remote-control valves ("RCV"), automatic shutoff valves ("ASV"), or equivalent technology, on all newly constructed and fully replaced gas transmission pipelines to meet a congressional mandate (Section 4 of the 2011 Pipeline Safety Act); NTSB safety recommendations that followed the San Bruno incident; U.S. General Accounting Office ("GAO") recommendations on the ability of operators to respond to commodity releases in HCAs; and technical reports commissioned by PHMSA on valves and leak detection from Oak Ridge National Laboratory ("ORNL") and Kiefner and Associates, respectively. Also, the NPRM would establish Federal minimum standards for the identification of ruptures and the initiation of pipeline shutdowns, segment isolation, and other mitigating actions, which are designed to reduce the volume of commodity released due to a pipeline rupture and thereby minimize potential adverse safety and environmental consequences. This NPRM would also establish standards for improving the effectiveness of emergency response.

- Pipeline Safety - Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (PHMSA-2011-0023 RIN 2137–AF39) - This rulemaking would amend the pipeline safety regulations relevant to gas transmission pipelines by adjusting the repair criteria in HCAs and creating new criteria for non-HCAs, requiring the inspection of pipelines following extreme events, requiring safety features on in-line inspection tool launchers and receivers, updating and bolstering pipeline corrosion control, codifying a management of change process, clarifying certain IM provisions, and strengthening IM assessment requirements.
- NTSB Recommendation P-12-17 Pipeline Safety Management Systems (API Recommended Practice 1173) – Conceptually, Pipeline Safety Management Systems are 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
- Providing 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."

The API 1173 Standard for Pipeline Safety Management Systems is only a recommended practice, but Columbia and NiSource have chosen to pursue the adoption and implementation of a Safety Management System ("SMS"). As an early adopter of deploying an SMS, Columbia has aggressively educated the entire workforce and key contractor resources on what it is and why we are using API 1173 as our guideline to measure progress. We have implemented a Corrective Action Program ("CAP") with all employees and key contractor resources that enables a more robust and formal process for identifying risks and developing actions to reduce risk. We have also established a new governance model to review and prioritize identified risks. The building of additional capacities within our SMS are underway and will continue, centered in process safety improvements, asset management improvements and safety culture improvements.

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 40.2 miles of transmission class pipelines (6.2 miles within HCAs) per the 2019 PHMSA Annual Report for Natural Gas Transmission and Gathering Systems for Columbia that meet this definition. Further, following the San Bruno, California explosion which occurred on a Pacific Gas and Electric 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 material and 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. PHMSA continues to focus heavily on Transmission Operations with the new Gas Transmission Rulemaking (promulgated October 1, 2019) that makes the inspection procedures and safety requirements of the various class locations more rigorous, and creates a definition of a MCA in addition to the existing HCA already defined in the rule. Future rulemaking regarding transmission class lines is already being discussed by PHMSA and industry representatives.

IV. <u>Strategic O&M Safety Initiatives</u>

Q. Please discuss Columbia's strategy regarding Operating and Maintenance ("O&M") safety initiatives going forward.

A. 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:

- **System Pressure Viability Program:** The System Pressure Visibility Program is an example of how Columbia's SMS is identifying risks and, at times, results in changes to priorities. The System Pressure Visibility Program focuses on the installation of digital pressure recording telemetry equipment at natural gas pressure regulator stations across the CPA operating territory to remotely monitor operating pressures and abnormal operating pressure conditions. The new digital devices will transmit pressure data back to Gas Control Supervisory Control and Data Acquisition (SCADA) systems where pressures and alarms will be monitored by Gas Control personnel and computer systems 24/7. The new digital devices will replace the existing analog paper pressure chart recording devices that are stand alone and unable to be observed in real time.

Benefits include the real time monitoring of natural gas pressure regulator stations, resulting in improved operational safety thru immediate awareness of operating pressure conditions at the regulator stations. The new digital devices will provide for additional trending and analysis opportunities given the pressure data granularity and data storage capabilities that analog devices cannot provide, further enhancing the understanding of how the system is or was operating at any point in time. The use of digital devices that communicate back to a SCADA system will reduce the human error that can occur when interpreting analog paper pressure chart recording devices. The Company is requesting $230,000 of incremental expense for the implementation of this program as reflected in Exhibit 104, Schedule 2, pg. 19, Line 11.

- **Enhanced Red Tag Process:** Another initiative identified by SMS is an enhanced red tag process, which consists of two processes. First, Columbia will re-design the red tag itself to enable current and new data to be collected about our customer's assets and safety issues encountered. Specifically, the re-design will enable the Company to standardize processes and procedures, provide clear actions for customers to take once an appliance has been red tagged, and will include a carbon copy of the tag for the Company's record retention purposes. Second, subsequent to appliances being red tagged, when requested by the customer, the Company will perform an inspection in the customer's home in order to proactively identifying unsafe gas situations downstream of the meter. Examples of when this could occur would be after a red tag is identified and repaired by a contractor, for a new home-owner or after a remodel. Such inspections identify risks that may be present downstream of the meter, while closing the loop in the company red tag process by providing a follow up for our customers. Allows for data collection on corrected red tag conditions. The Company is requesting $20,000 of incremental expense for the implementation of this program as reflected in Exhibit 104, Schedule 2, pg. 19, Line 11.

- **Low Pressure Program.** Columbia is continuing its Low Pressure ("LP") Program that resulted in enhanced engineering designs, enhanced damage prevention practices and changes to work rules for tie-ins, construction involving system configuration changes, and any O&M work that involved excavation to include additional field monitoring of stations. Installation of automatic shut off devices continue to be the primary form of additional overpressure protection.
- **Cross Bore Program.** 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 has inspected over 445.2 miles of sanitary and storm sewer mains, and 29,872 customer laterals since

2013. During this inspection, 475 cross bores were identified, with 311 of those involving Columbia's system. Given program results, cross bores are now identified as a high risk in Columbia's DIMP plan. Consistent with Company's proposal in its 2020 rate case (Docket No. R-2020-3018835) to accelerate this program by increasing resources to it, the program is currently on pace to be completed in 31 years.

- **Legacy Service Line Enhancement Program.** In January 2019, Columbia implemented a legacy service line record enhancement program, and was granted part of its request to fund this initiative in the Company's 2020 rate case. Based upon the Commission's recent order, the Company will move forward with this program in 2021, which will correct inaccurate and/or incomplete data within legacy records. This is vital, as accurate records are critical to ongoing maintenance of the system.
- **Field Assembled Riser Replacement Program.** During the winter of 2014-2015, failures were experienced with field assembled risers and as such, they have been identified as a high risk in Columbia's DIMP plan. Columbia developed a program to address the risk of field assembled riser failures. The program included a survey of customer-owned and Company-owned service lines to identify and quantify field assembled risers in use. Columbia utilized the collected data to further assess DIMP risk and prioritize efforts. Columbia began replacing field assembled risers identified on Company-owned service

lines in 2015. Recognizing the same risk existed on customer-owned facilities, the Company petitioned for a waiver to address customer-owned field assembled risers, which was approved by the Pennsylvania Public Utility Commission on December 6, 2018. In deciding the Company's 2020 rate case, the Commission granted, in part, Columbia's request for funding in order to accelerate this important program. At this time, Columbia is working to build in the acceleration of its field-assembled riser program into its 2021 work plans.

- **Picarro Leak Detection Program**. Columbia has employed the Picarro platform system to enhance its process for leak detection and to refine the prioritization of repairs and replacements for its natural gas distribution system. The use of the Picarro Leak Detection System will serve to advance the Company's leak detection capabilities, as well as estimate leak density and methane emissions across its service territory. Additionally, the Picarro system will support the Company's Operations and Construction departments by aiding in the prioritization of system risk for the Company's ongoing infrastructure replacement program, and by providing quality assurance checks following the installation of new infrastructure.
- **Safety Management System (SMS).** As previously noted in my testimony, Columbia is pursuing the adoption and implementation of a Safety Management System (SMS). As an early adopter of deploying an SMS, Columbia has aggressively educated the entire workforce and key contractor

resources on what it is and why Columbia is using API 1173 as our guideline to measure progress. The Company has implemented a Corrective Action Program (CAP) with all employees and key contractor resources that enables a more robust and formal process for identifying risks. Columbia also has established a new governance model to review and react to risks identified. The building of additional capacities within the SMS are underway and will continue, centered in process safety improvements, asset management improvements and safety culture improvements.

The O&M safety initiatives identified above, in conjunction with the Company's ongoing 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. The implementation of SMS will continue to mature and strengthen the culture of risk identification and reduction at Columbia.

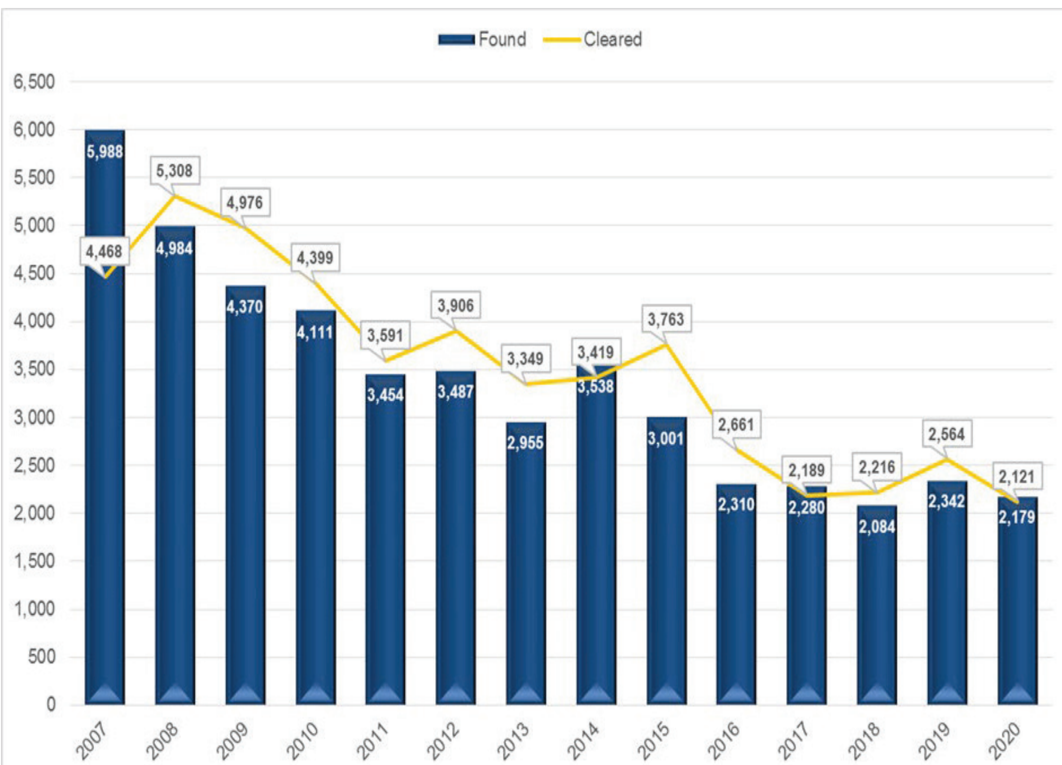
Q. Are there any additional details demonstrating the improvement of Columbia's system operations?

A. Some of the results from DIMP-driven practice enhancements or procedural changes, which improve Columbia's system, include:

Leakage Reduction: Since the inception of our accelerated infrastructure replacement program, Grade 2 leaks have been significantly reduced, thereby increasing the safety of our customers. Figure 4 below shows a comparison of Grade

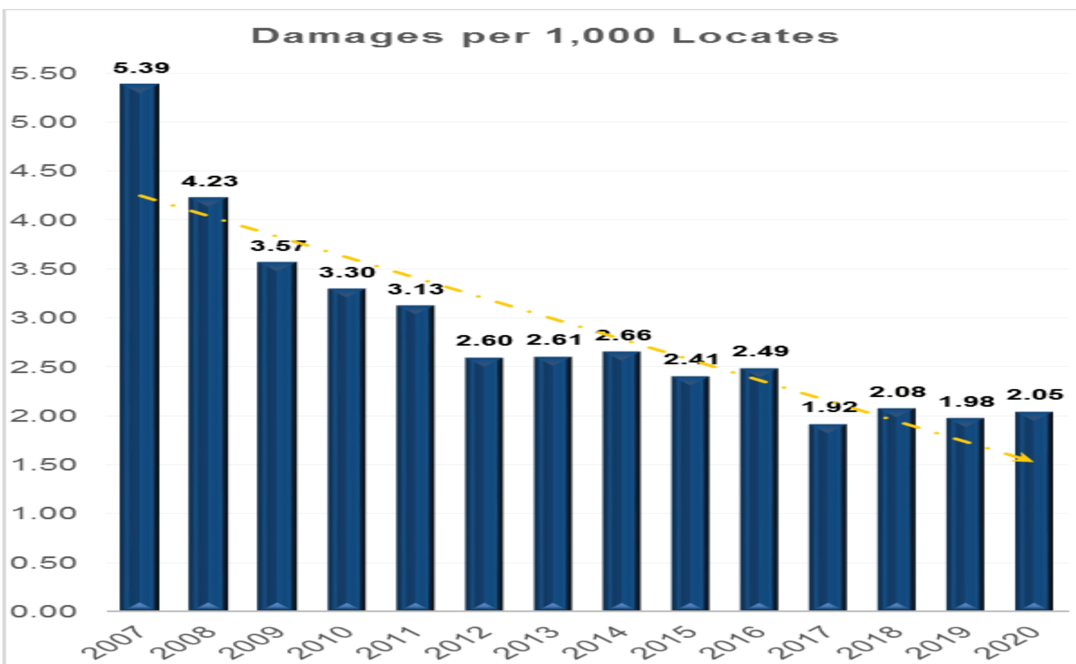
2 leaks found during the year, as compared to Grade 2 leaks repaired during the year. In the last ten years alone, Columbia's pipeline replacement efforts were responsible for cutting the number of leaks found from 4,111 in 2010 to only 2,179 in 2020. That's nearly a 50% reduction in leaks. That reduction in leaks improves safety, reduces methane emissions, and even improves service to customers since there are fewer service interruptions due to water offs and leakage repairs. Going forward, reduction of Grade 2 leaks will continue to be a focus.

Figure 4
Columbia Gas of Pennsylvania, Inc.
Grade 2 Leaks



Damage Prevention: The Company continues to focus on damage prevention. Since 2007, the Company reduced damages per 1,000 locates, as noted in Figure 5 below. In particular, the Company has focused on improving third party damages per 1,000 locates, as excavation damage is the leading cause of federally reportable pipeline incidents. These efforts have contributed to the 62% reduction in the damage rate on the Columbia system between 2007 and 2020, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 2.05 through December 31, 2020, as shown in Figure 5 below.

Figure 5



- *Training Center*. Columbia constructed a new training center that opened in mid-2016 which provides the facilities needed to conduct classroom training, enhanced hands on training and operator qualification training. The facility is currently being used for multiple training purposes, including: new employee training, employees transitioning into higher skilled positions, annual refresher training for the existing workforce and emergency response training. 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. Columbia 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 incorporates 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 educates employees on every aspect of the job and its importance, from physical work performed to its accurate documentation.

V. Columbia's Operating Performance

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. Over the course of the last six years, Columbia initiated and/or continues to expand on a number of customer service delivery improvements. These improvements include 45-minute or less emergency response times and providing customers the option of a two hour appointment window, which have resulted in a safer and better experience for our customers. For example:

- Columbia implemented 45-minute or less Emergency Response Rate targets. 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 safely and as quickly 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. Additionally, the Company negotiated residency requirements to better support emergency response efforts. The results of these focused efforts have resulted in improved performance in emergency response times. A comparison of the data showing the 45-minute or less response rates from 2015 to 2020 as follows:

	2015	**2016***	**2017**	**2018**	**2019**	**2020**
Day	96.79%	99.17%	99.16%	98.70%	98.99%	99.51%
Evening	90.95%	95.24%	94.87%	95.61%	97.28%	97.09%
Holiday	91.59%	92.11%	85.25%	86.32%	88.79%	95.35%
Overnight	85.87%	94.86%	95.19%	92.43%	90.42%	95.62%
Weekend	82.76%	91.83%	92.66%	91.72%	93.66%	95.31%
Total	**92.68%**	**96.88%**	**96.82%**	**96.40%**	**97.28%**	**98.12%**
**Note: Columbia implemented 45 minute response targets in 2016*						

- 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[4]. As more and more customers need to take time off

[4] The percent of customer-generated appointments that are met within the appointment window or according to state regulation, where applicable.

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 97.10% in 2014, to a rate of 99.5% in 2020.

Q. Please describe the Company's reduction in Occupational Safety and Health Administration ("OSHA") recordable injuries.

A. Columbia continues to enhance its culture of safety for customers, communities, and employees. Employee safety has significantly improved as Columbia has experienced a significant reduction in OSHA Recordable Injuries. For comparison, at the end of 2006, Columbia had 48 OSHA recordable injuries. This past year in 2020 that number was 14 OSHA recordable injuries which is a reduction in frequency of 71%. Columbia has previously received industry awards from both the American Gas Association and the Energy Association of Pennsylvania in recognition of its safety performance. Our goal is for every employee to go home safe and healthy every day. Columbia's safety efforts include:

- Columbia delivers safety training to all employees. This training spans skills from employee safe driver training to office ergonomics.
- Columbia uses Safety Telematics in Company vehicles 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 has local and state-wide safety teams made up of engaged front line workers, leaders, contractors and managers. These teams make recommendations on, and implement, safety improvement opportunities.
- Columbia performs a post-incident root cause analysis involving the team of the involved business unit of every OSHA recordable injury and preventable vehicle collision that involves a Columbia employee. Near miss discussions are also conducted.
- Columbia has implemented a job site safety observation program in which leaders perform job site safety observations in the field to coach employees on safe working behaviors, field work activities, and to provide feedback to employees' on their safety performance.

- Columbia employees evaluate risk and the work hazards at each jobsite prior to beginning work and complete a pre-job safety briefing which is reviewed with each employee on the job site or project. A new pre-job safety briefing is completed when the risks or the scope of the work changes so that our teams perform our work as safely as possible. This process was reviewed and updated in 2020 with updated pre-job safety briefing form supported by employee computer-based training in November of 2020.
- In March of 2020, Columbia hired an additional safety professional to support our PA East operating area. Our team of safety professionals include a Safety Manager and four Safety Coordinators who each support one of operating areas.

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 timelier basis than if it were only meeting the minimum federal standards.

Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 14-R (Public)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
C. J. ANSTEAD
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

Q. **Please state your name and business address.**

A. C. J. Anstead, 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 General Manager and Vice President.

Q. **Have you previously filed testimony in this matter?**

A. Yes.

Q. **What is the purpose of your rebuttal testimony?**

A. I will address the testimony of Michael Hicks, Sr., who testified at the afternoon public input hearing on June 16, 2021.

Q. **Mr. Anstead, are you familiar with the testimony of Michael Hicks, Sr., given at the public input hearing on June 16?**

A. Yes. Mr. Hicks indicated that he is currently without service from Columbia because the Company instructed him to replace the service line at his residence at 2 Eighth Street in Uniontown, Pennsylvania, and he was unable to afford to pay a plumber the estimated cost of $6,000 to do so. Mr. Hicks was not specific as to the timing of the discontinuation of this natural gas service or as to his attempt to restore service.

Q. **Has Columbia looked into its records regarding the discontinuation of service at 2 Eighth Street in Uniontown?**

A. Yes. Columbia's records indicate that [**BEGIN CONFIDENTIAL**] [redacted]

[redacted] [END CONFIDENTIAL]

Q. Was his service restored at that time?

A. Unfortunately, no.

Q. Did the customer service line at 2 Eighth Street in Uniontown have anything to do with the inability to restore Mr. Hicks' service in January of 2011?

A. No. Service could have been restored in January of 2011 without any requirement to replace the customer service line because Mr. Hicks' service line had not yet been abandoned under Section 59.36 of the Commission's regulations.

Q. Was the service line to 2 Eighth Street in Uniontown eventually abandoned?

A. Yes. In November of 2014, Columbia abandoned the inactive service line at that address in compliance with Section 59.36(2). Abandoning an inactive service line involves physically cutting the connection between the service line and Columbia's main line, and purging the service line of gas.

Q. After that, did Mr. Hicks contact Columbia about restoring his service?

A. Yes. In December of 2015, thirteen months after the service line had been abandoned, Mr. Hicks contacted Columbia to request the restoration of his service. Since the service line had been physically abandoned, Columbia would have advised him that he would be required to replace the customer-owned portion of the service line.

Q. Could Columbia have replaced the customer-owned portion of the service line?

A. No. Under Columbia's tariff, customers in Fayette County own, and are responsible for maintaining, the portion of the service line that is beyond Columbia's point of delivery at their premises. The point of delivery is designated as the curb valve or, if there is no curb valve, the property line. Columbia's tariff also provides that the customer is responsible for installing, at the customer's expense, the service line to the point of connection to Columbia's main. The Commission has granted limited waivers to these tariff provisions where service line replacement must be done in conjunction with a main replacement project. Since the need to replace the service line at 2 Eighth Street in Uniontown was not related to a main replacement project, those waivers do not apply to Mr. Hicks' situation.

Q. Could Columbia just have restored service through the existing service line that had been abandoned?

A. No. Whether a service line is company-owned or customer-owned, once a service line has been physically abandoned by severing the connection to Columbia's main, Columbia will not re-introduced service through the abandoned service line.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 15-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

REBUTTAL TESTIMONY OF
KIMBERLY K. CARTELLA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

Q. Please state your name and business address.

A. My name is Kimberly K. Cartella. My business address is 3101 N. Ridge Rd., Lorain, OH 44055.

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

A. I am employed by NiSource Corporate Service Company ("NCSC") as Director of Compensation. I develop and implement strategies for broad based compensation and incentive programs provided to the employees of NiSource Inc. ("NiSource") and its subsidiaries, including Columbia Gas of Pennsylvania ("Columbia" or the "Company").

Q. What is your educational background?

A. I received a Bachelor of Science degree in Financial Planning from Purdue University in 1992. I am a certified Professional in Human Resources ("PHR") and a Certified Compensation Professional ("CCP").

Q. What is your employment history?

A. I have worked for NiSource in a human resources capacity since 1999. I have held the position of Director of Compensation at NiSource since January 2019. Prior to that, I was Manager of Compensation, Senior Compensation Analyst, Senior Human Resource Consultant, and Executive/College Recruiter.

Q. Have you previously submitted testimony in matters before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. I previously submitted rebuttal testimony in CPA's base rate proceedings at

Docket No. R-2015-2468056, Docket No. R-2016-2529660, Docket No. 2018-2647577, and Docket No. 2020-3018835.

Q. What is the purpose of your rebuttal testimony?

I will respond to the testimony served in this proceeding by the Bureau of Investigation and Enforcement ("I&E") witness John Zalesky and Office of Consumer Advocate ("OCA") witness David Effron regarding employee incentive and stock compensation.

Q. Please describe NiSource's total rewards philosophy.

A. NiSource's total rewards philosophy is to compensate employees and provide benefits that are competitive in comparison to the utility industry, as well as general industry (non-utility) employers, in order to attract, retain and motivate employees who are qualified to perform the functions needed by the Company. This philosophy enables the Company to meet its obligations to provide safe, reliable and affordable service to its customers. This philosophy is consistent across all NiSource companies.

Q. Please briefly describe Mr. Zalesky's position regarding incentive compensation.

A. Mr. Zalesky proposes that the Company use a three year historic average for incentive compensation expense and states that such a proposal is justified in anticipating future results. Mr. Zalesky proposes to disallow $925,097 in FPFTY incentive compensation to be paid by the Company and a reduction of $782,759 for NCSC. He also bases his three year average calculation on accrued expense, not actual payouts.

Company witness Paloney (Columbia Statement No. 9-R) provides further rebuttal with respect to the calculation.

Q. Do you agree with Mr. Zalesky's recommendation?

A. No. As noted by Company witness Paloney in her Rebuttal Testimony (Columbia Statement No. 9-R), Mr. Zalesky's adjustment departs from the principles of a FPFTY claim in seeking an adjustment based on historical results. Incentive compensation is based upon achievement of performance metrics including customer service, safety, and financial as well as individual employee contributions and performance which is all supported by NiSource's total rewards philosophy. The proposed disallowance should be disregarded.

Q. Please briefly describe the position of Mr. Zalesky on stock rewards.

A. Mr. Zalesky proposes 100% disallowance of the stock reward cost. He claims stock rewards are linked to financial goals such as earnings per share, return on equity, or appreciation of the parent company's stock.

Q. Do you agree with Mr. Zalesky's recommendation?

A. No. These rewards are not based upon return on equity or appreciation of the parent company's stock. Stock rewards are based on achievement of metrics that include safety, customer perception, employee culture, environmental, financial and employee diversity. Goals include: top decile results in the National Safety Council Barometer Survey, top quartile performance in the J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies, top quartile performance in the Employee

Engagement Survey Culture Index, reduction of greenhouse gas emissions, etc. See Statement No. 15-R Attachment A for performance measures for stock rewards for 2018-2020 and CONFIDENTIAL Attachment B for performance measures for 2021. The proposed disallowance should be disregarded.

Q. Mr. Zalesky further asserts, at page 25 of his testimony, that stock rewards are limited to executives, and that it is not clear to him how stock reward are related to safe and reliable service. Please comment.

A. Stock rewards are part of the Company's design of its total rewards program to remain competitive with other employers, retain employees, and further drive requirements to provide safe, reliable and cost-effective service to its customers. An individual's incentive compensation could be reduced if safety or customer goals are not achieved. The Company recognizes that the stock rewards should not be based upon financial metrics alone but should also include the achievement of goals that are beneficial to customers. Stock reward metrics include safety, customer perception, budget, employee culture, environmental, and employee diversity.

Q. Please briefly describe Mr. Effron's position regarding incentive compensation.

A. Mr. Effron proposes to reduce the costs associated with the Company's incentive compensation through application of the Historic Test Year ("HTY") ratio of incentive compensation to labor expense to the FPFTY labor expense. Mr. Effron proposes to disallow $810,000 in FPFTY Incentive Compensation to be paid by the Company.

Q. Do you agree with Mr. Effron's recommendations?

A. No. In regard to incentive compensation, similar to I&E witness Zalesky's recommendation, Mr. Effron's adjustments depart from the principles of a FPFTY claim in seeking an adjustment that is based on historical results. Witness Paloney addresses this concern in her rebuttal testimony.

Q. Please briefly describe the position of Mr. Effron's on stock rewards.

A. Mr. Effron recommends 100% disallowance of costs related to stock rewards which totals $2.7 Million. Mr. Effron opines that stock rewards are solely based on attainment of financial goals and stock price appreciation and should be removed from the cost of service.

Q. Do you agree with Mr. Effron's recommendations?

A. No. Mr. Effron's claim that stock rewards are solely based upon appreciation in stock value is not correct. Stock rewards include a variety of metrics as shared above.

Q. Why does NiSource provide incentive compensation and stock rewards?

A. Incentive compensation and stock rewards are part of the Company's design of its total rewards program to remain competitive with other employers, retain employees, and further drive requirements to provide safe, reliable and cost-effective service to its customers. An individual's incentive compensation could be reduced if safety or customer service goals are not achieved.

In addition, stock rewards are a common element of compensation at certain levels of organizations throughout the U.S. and, as such, these costs should be allowed. Stock rewards allow Columbia and NCSC to attract and retain individuals at executive levels and doing so would be difficult to accomplish without this element of compensation.

Q. From a policy perspective, why is it important that stock rewards be recovered in base rates?

A. If the Commission disallows recovery of stock rewards, it sends the message that variable incentive compensation is not valued as a viable tool to encourage company efficiencies and promote customer service and safety goals. Further, denial of recovery of stock rewards means that fixed base pay without incentives would become the preferable means to attract, motivate, and retain talented employees while retaining a reasonable opportunity for full recovery of that compensation. Incentive compensation is an element of competitive total compensation in the labor market both within the utility industry and within the broader employer base. The importance of incentive plans as part of a company's total compensation package is evidenced in the following excerpt from the Aon Hewitt survey "U.S. Total Compensation Measurement (TCM) - Executive Compensation Policies and Programs U.S. Edition" (2018), which included participation by 436 companies.

> Of these 436 companies, 81% reported at least one form of long-term incentive. Topics covered for each long-term incentive plan include eligibility, grant frequency, range of award opportunity, exercise restrictions, form and timing of payment, and treatment of dividends.

> Of those companies reporting a long-term incentive plan, 73% have two or more vehicles in 2018 as compared to 76% in 2017. Three or more plans were reported by 32% of the companies this year.

With 81% of companies surveyed providing at least one form of long-term (generally stock) incentive, the Company and NCSC would be at a major disadvantage in attracting new executives or retaining current leaders without the ability to also provide such forms of compensation.

Q. Do customers benefit from retaining existing quality leadership and attracting new corporate leaders?

A. Yes. Retaining key leaders and attracting new talented individuals is critical to maintaining high quality of service, efficiency and safety; therefore, offering stock rewards is an appropriate cost of providing reliable service to Columbia's customers. If the Company did not provide stock rewards, it would be at high risk of losing talent to competitors. The potential departure of Company leadership would create a loss of valuable skills and would have a significant financial impact in the form of turnover costs, including recruiting, relocation, and training costs. In addition, leadership sets the tone and direction for the Company. Failure to retain and attract experienced, skilled leaders can adversely affect Columbia's ability to continue to provide safe and reliable service for its customers.

Q. Do you have any further comments with respect to Mr. Zalesky's and Mr. Effron's testimony on incentive compensation and stock rewards?

A. Yes. The incentive compensation plan and goal setting process are designed to support safety, customer, and financial goals. Also, I am advised by counsel that the Commission has allowed recovery of incentive compensation as a part of payroll where the compensation plan includes provisions that are designed to provide benefits to customers, as the Company's plan does. Moreover, I am aware of the PPL Electric Utilities decision that permitted incentive compensation consistent with prior Commission decisions when such compensation programs are focused on improving operations effectiveness. *Pa. PUC v. PPL Electric Utilities Corp., R-2102-2290597,* (Order entered Dec. 28, 2012).

Q. Should the increase in FTY and FPFTY incentive compensation be allowed?

A. Yes, increases in the FTY and the FPFTY for incentive compensation should be permitted as explained above and as supported by Company witness Paloney in her rebuttal testimony.

Q. Does this complete your rebuttal testimony?

A. Yes.

2018 LTI Plan Design and Measures

PUBLIC VERSION

K. Cartella
Statement 15-R
Attachment A

2018 LTI Measures			
2018 Grant Type	**Vesting Criteria** 3-Year Performance Period	**Weight**	**Measurement / Leverage**
Restricted Stock Units	Time Based	20%	N/A
Performance Shares	Performance Based		
1. Cumulative NOEPS		65%	Trigger = $4.13: 50% of award Target = $4.34: 100% of award Stretch = $4.55: 200% of award
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return			• Top quartile=25% increase in cumulative NOEPS shares vested • Bottom quartile=25% decrease in cumulative NOEPS shares vested • No interpolation
2. Customer Value Index		15%	See next page

2018 LTI: Customer Value Framework

PUBLIC VERSION

K. Cartella
Statement 15-R
Attachment A

Customer Value Framework for Long Term Incentive				
Area of Focus	**Measures**	**Weight**	**Baseline 2017**	**3-Year Goal** Achievement at end of 3 years
Safety	National Safety Council Barometer Survey	20%	Top quartile	Top decile by end of year 3
Customer	J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies	20%	Bottom of second quartile	Top quartile by end of year 3
Financial	O&M	20%	Bottom of third quartile	O&M per plan
Culture	Continuous Improvement Management Practices Organizational Health Index	20%	Second quartile	Top quartile by end of year 3
Environmental	Greenhouse Gas Reductions	20%	Emissions 11.19 million tonnes	Emissions 9.19 million tonnes

PUBLIC VERSION

2019 LTI Plan Design and Measures

K. Cartella
Statement 15-R
Attachment A

2019 LTI Measures	
2019 Grant Type	**Weight**
Restricted Stock Units	20%

Performance Shares	80%	**2019-2021 Goals**	
1. Cumulative NOEPS	65%	Stretch = $4.35 Target = $4.14 Trigger = $3.93	
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile	+25%
		Second Quartile	+0
		Third Quartile	+0
		Fourth Quartile	-25%
2. Customer Value Framework (Enterprise Level Measures)	15%	See next page for details	

2019 LTI: Customer Value Framework

PUBLIC VERSION

K. Cartella
Statement 15-R
Attachment A

Customer Value Framework for Long Term Incentive				
Area of Focus	**Measures**	**Weight**	**Baseline 2018**	**3-Year Goal** Achievement at end of 3 years
Safety	National Safety Council Barometer Survey	20%	Top decile	Remain in top decile
Customer	J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies	20%	Bottom of second quartile	Achieve top quartile
Financial	O&M Financial Plan	20%	NA	Maintain flat O&M per plan
Culture	Organizational Health Index	20%	Second quartile	Achieve top quartile
Environmental	Greenhouse Gas Reductions	20%	Emissions 12.21 million tonnes	Emissions 11.85 million tonnes

2020 LTI Plan Design and Measures

2020 LTI Measures	
2020 Grant Type	**Weight**
Restricted Stock Units	20%

Performance Shares	80%	**2020-2022 Goals**	
1. Three Year Cumulative NOEPS[2]	65%	Stretch = $ 4.60 Target = $ 4.38 Trigger = $ 4.16	
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile	+25%
		Second Quartile	+0
		Third Quartile	+0
		Fourth Quartile	-25%
2. Customer Value Framework (Enterprise Level Measures)	15%	See next page for details	

2020 LTI: Customer Value Framework

K. Cartella
Statement 15-R
Attachment A

Customer Value Framework for Long Term Incentive				
Area of Focus	**Measures**	**Weight**	**Baseline 2019**	**3 Year Goal** Achievement at end of 3 years
Safety	National Safety Council Barometer Survey	25%	Top decile	Remain in top decile
Customer	J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies	25%	Second quartile	Top quartile
Culture	Employee Engagement Survey: Culture Index	25%	Second quartile	Top quartile
Environmental	Greenhouse Gas Reductions	25%	Emissions 9.83 million tonnes	Emissions 9.73 million tonnes

COLUMBIA STATEMENT NO. 16-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)
	)
	)
	)
v.	)
	)
	)
	)
Columbia Gas of Pennsylvania, Inc.	)
	)
	)

REBUTTAL TESTIMONY OF
PATRICK L. BARYENBRUCH
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 14, 2021

DOCKET NO. R-2021-3024296
COLUMBIA GAS OF PENNSYLVANIA
REBUTTAL TESTIMONY OF PATRICK BARYENBRUCH

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REBUTTAL TESTIMONY

PATRICK L. BARYENBRUCH

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, position of employment and business address.

A. My name is Patrick L. Baryenbruch. I am the President of my own consulting practice, Baryenbruch & Company, LLC, which was established in 1985. In that capacity, I provide consulting services to utilities and their regulators. My business address is 2832 Claremont Road, Raleigh, North Carolina 27608.

Q. Summarize your academic and professional background.

A. I received a Bachelor's degree in Accounting from the University of Wisconsin-Oshkosh and a Master's in Business Administration degree from the University of Michigan. I am a member of the American Institute of Certified Public Accountants and the North Carolina Association of Certified Public Accountants.

I began my career with Arthur Andersen & Company, where I performed financial audits of utilities, banks and finance companies. I left to pursue an M.B.A. degree. Upon graduation from business school, I worked with the management consulting firms of Theodore Barry & Associates and Scott Consulting Group (now ScottMadden) before establishing my own firm.

Q. Do you hold any professional certifications?

A. Yes. I am a Certified Public Accountant (CPA) with active licenses from the states of Wisconsin and North Carolina. I am a Certified Information Technology Professional (CITP), an accreditation awarded by the American Institute of Certified Public Accountants to CPA professionals who can demonstrate expertise in information technology management. I also hold a Global Information Assurance Certification (GIAC) in cybersecurity from the SANS Institute.

Q. Have you provided testimony in other regulatory proceedings on the issue of utility/affiliate transactions?

A. Yes. In the course of my career, I have performed more than 120 evaluations of affiliate charges to 42 utility companies. I have acted as an expert witness on utility/affiliate charges in over 80 rate case proceedings before regulators in 20 states. Schedule PLB-1 presents my previous affiliate transaction-related assignments.

Q. What other work experience do you have with the utility industry?

A. Besides my rate case support work, much of my career has been spent as a management consultant for projects related to the utility industry. I have performed consulting assignments for more than 60 utilities and 10 public service commissions. I have participated as project manager, lead consultant or staff consultant for 24 commission-ordered management and prudence audits of public utilities. Of these, I have been responsible for evaluating the area of affiliate charges and allocation of corporate expenses in the Commission-ordered audits of Connecticut Light and Power (now Eversource), Connecticut Natural Gas, General Water Corporation (now United Water Company), Philadelphia Suburban Water Company (now Aqua America) and Pacific Gas & Electric Company.

My firm performed the commission-ordered audit of Southern California Edison's 2002, 2003, 2004 and 2005 transactions with its non-regulated affiliate companies.

For 20 years, I provided consulting services related to information technology (IT) infrastructure within the utility industry. These projects involve improvements in IT business management practices of utility IT organizations, covering processes such as planning, risk management, performance measurement and reporting, cost recovery, budgeting, cost management and personnel development.

I acted as the project manager or member of the project management team for 20 large-scale IT implementation projects involving a total of 800,000 hours work of hundreds of utility client employees and contractor personnel.

II. INTRODUCTION

Q. Have you provided testimony in this proceeding?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. I am presenting rebuttal testimony addressing the direct testimony of Mr. David Effron, witness for the Pennsylvania Office of Consumer Advocate.

Q. What part of his direct testimony will you address?

A. I will cover his comments in section III.C.1.f. NCSC Expense and his recommendation that $14,959,000 in NCSC expense-related charges be eliminated from Columbia's 2022 Fully Projected Future Test Year (FPFTY) operations and maintenance expenses. More specifically, I will address the increase in NCSC charges resulting from the divestiture of Columbia Gas of Massachusetts (CMA). Company witness Ms. Nicole Paloney will address the portion of increased NCSC charges associated with the expansion of the Safety Management System of NiSource Inc. (NiSource).

Q. How much are NCSC operations and maintenance (O&M)-related charges to Columbia expected to increase over those of the historical test year (HTY)?

A. 2020 HTY actual NCSC O&M charges to Columbia totaled $62,365,898. Future Test Year (FTY) 2021 O&M charges to Columbia are estimated to total $73,507,000. FPFTY 2022

O&M charges to Columbia are projected to be $76,860,000. From the HTY to the FPFTY, NCSC O&M charges increase by approximately $14.5 million.

Q. What portion of the projected increase in NCSC charges are associated with the divestiture of CMA?

A. Approximately $11.4 million.

Q. What is the basis for Mr. Effron's recommended disallowance?

A. Essentially, Mr. Effron believes Columbia should only be allowed 2020 HTY NCSC O&M charges escalated by historical increases without regard for NCSC's cost of providing services to Columbia.

Q. Do you agree with Mr. Effron's recommended disallowance?

A. No. I disagree for the following reasons:

1) Columbia's charges from NCSC are reasonable, even with the additional NCSC charges associated with the CMA divestiture.

2) NCSC's projected charges to Columbia represent its cost to deliver services and are in line with the Affiliate Interest Agreement (AIA) between Columbia and NCSC.

3) Accepting the disallowance would represent inconsistent treatment of NCSC charges to Columbia. In the past, the growth of NiSource's regulated utility business has enabled NCSC expenses to be allocated over a larger customer base. Columbia was never permitted in a rate case to retain a share of the associated economies of scale that flowed through to its customers. It is inconsistent and unfair to use a decrease in NiSource's total customer base as the basis for disallowing NCSC charges to Columbia.

4) The customer base of utilities is dynamic, regularly increasing and, sometimes, decreasing. NiSource's sale of CMA is not an unusual event in the utility industry.

5) The services provided by NCSC are vital and allow Columbia and its customers to take advantage of synergies and economy of scale that come from a service company arrangement.

These points are covered in the remainder of my testimony.

III. NCSC CHARGES ARE REASONABLE

Q. Concerning your first point, how did you determine NCSC charges to Columbia are reasonable?

A. I compared NCSC's charges to Columbia to similar charges of other utilities. I performed two cost comparisons: (1) service company Administrative and General (A&G) charges per customer and (2) total A&G expenses (both incurred by the utility and allocated from a service company affiliate) per customer. I compare A&G costs because substantially all service companies that are part of a utility holding company structure deliver A&G services to their utility affiliates. This is true because there are considerable economies of scale derived from centralizing the management of corporate (i.e., A&G) services such as information technology, finance and human resources.

Service Company A&G Charges per Customer

Q. What were Columbia's 2020 A&G charges per customer from NCSC?

A. An analysis of Columbia's 2020 NCSC charges by Federal Energy Regulatory Commission (FERC) account is shown in Schedule PLB-2. A&G costs are those charged to the 900 series of FERC accounts. As calculated below, Columbia was charged $130 per customer for NCSC A&G-related services during 2020.

2020 NCSC A&G-Related Charges per Customer

NCSC 2020 A&G Charges	$ 57,139,961
Columbia Customer Count (12/31/2020)	440,651
2020 NCSC A&G Charges per Customer	$ 130

Source: Company data; Baryenbruch & Company, LLC, analysis

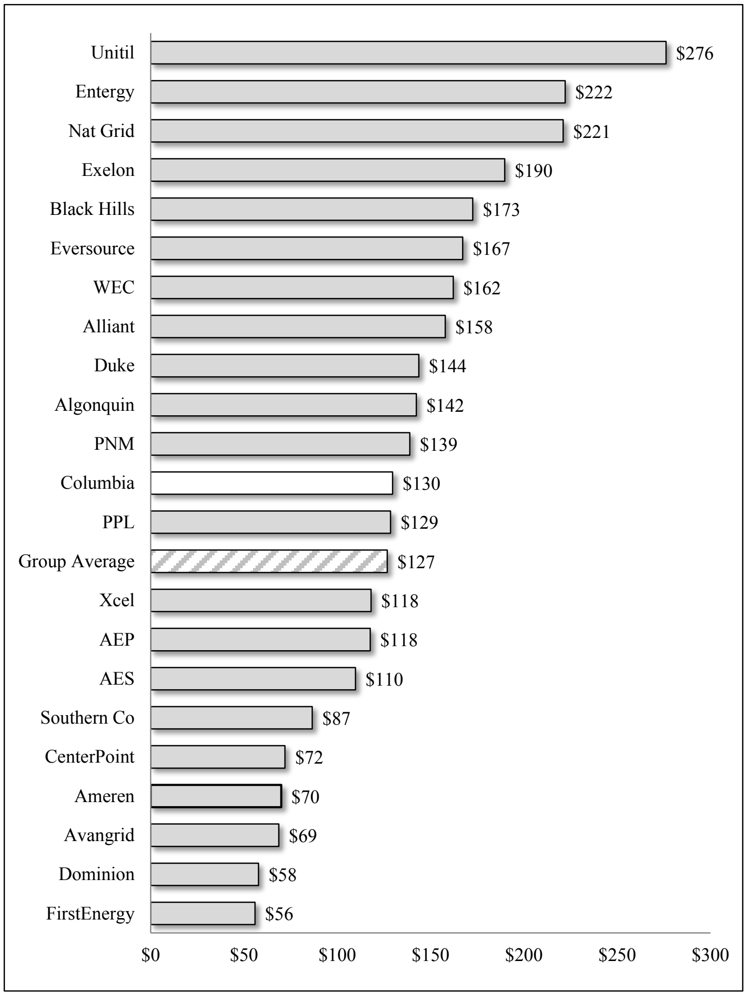
Q. Which companies make up the comparison group and what are their service companies' 2020 A&G charges per customer?

A. The comparison group consists of utility service companies that file a Form 60 with the FERC. For 2020, a Form 60 was filed by over 30 service companies associated with 22 utility holding companies, including NiSource. NiSource/NCSC is not included in the comparison group because only its charges to Columbia are relevant to this analysis. A&G charges per customer for the other 21 utility companies are calculated in the table below.

Utility Company	2020 Regulated Retail Service Company A&G Charges	Regulated Retail Customers	Cost per Customer
AEP	$646,851,371	5,500,000	$ 118
AES	$87,069,654	793,500	$ 110
Algonquin	$96,401,587	677,000	$ 142
Alliant	$219,478,305	1,390,000	$ 158
Ameren	$230,863,986	3,300,000	$ 70
Avangrid	$226,514,627	3,300,000	$ 69
Black Hills	$220,941,474	1,280,000	$ 173
CenterPoint	$534,602,218	7,427,500	$ 72
Dominion	$402,456,711	6,963,000	$ 58
Duke	$1,370,697,707	9,541,000	$ 144
Entergy	$711,090,586	3,202,000	$ 222
Eversource	$670,381,082	4,009,000	$ 167
Exelon	$1,897,471,383	10,000,000	$ 190
FirstEnergy	$335,285,366	6,000,000	$ 56
Nat Grid	$1,547,203,999	7,000,000	$ 221
PNM	$110,905,641	798,700	$ 139
PPL	$347,100,031	2,700,000	$ 129
Southern Co	$747,147,289	8,630,000	$ 87
Unitil	$53,216,126	192,700	$ 276
WEC	$371,892,429	2,294,000	$ 162
Xcel	$673,297,436	5,700,000	$ 118
Total/Average	$11,500,869,009	90,698,400	$ 127

Source: FERC Form 60; Baryenbruch & Company, LLC, analysis

The graph below shows Columbia's 2020 average of $130 is just above the comparison group average of $127. The per-customer costs for 11 companies, 52% of the comparison group, are higher cost than that of Columbia.



Source: Company information; FERC Form 60; Baryenbruch & Company, LLC, analysis

Q. What happens when you factor in the additional $11.4 million in future NCSC allocations due to the divestiture of CMA?

A. If I assume the $11.4 million is made up of the same percent of A&G expenses (91.6% as shown in Schedule PLB-2) as were NCSC's 2020 actual charges, then the 2021 post-divestiture charges per Columbia customer increases to $153, as calculated below.

Post Divestiture NCSC A&G-Related Charges per Customer

NCSC 2020 A&G Charges		$ 57,139,961
Additional NCSC Allocation A&G Charges		
Total Additional Allocation	$ 11,400,000	
2020 Actual A&G Percentage	91.6%	
Additional A&G Amount	$ 10,444,740	$ 10,444,740
Total Post Divestiture A&G Charges		$ 67,584,701
Columbia Customer Count (12/31/2020)		440,651
Post Divestiture A&G Charges per Customer		$ 153

Source: Company data; Baryenbruch & Company, LLC, analysis

Q. What are the comparison group's estimated 2021 A&G charges per customer?

For the comparison group, I escalated their actual 2020 costs per customer by 2.44%, a rate that Mr. Effron indicates in his testimony is reasonable for the increase in total service company expenses.

> *This translates into an increase of 2.44% per year over this two year period, which does not seem unreasonable.* (David Effron direct testimony, page 26 lines 13-15)

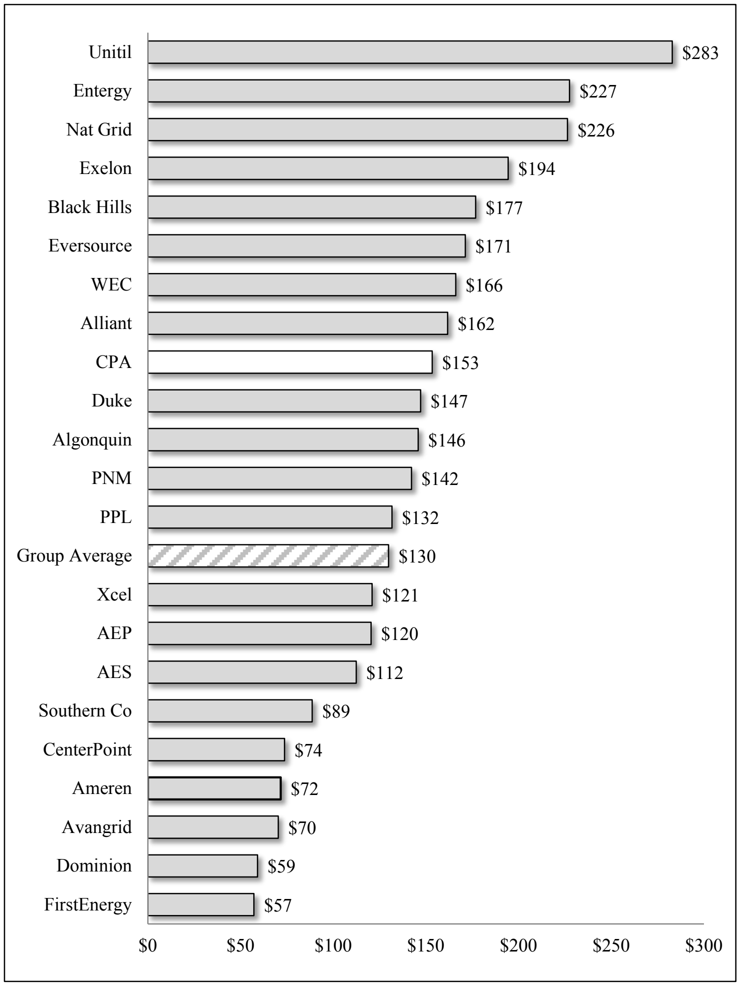
As shown in the table below, the comparison group's estimated 2021 cost per customer is $130.

		2021 Estimate	
Utility Company	2020 Cost per Customer	Escalation Rate	Escalated Cost per Customer
AEP	$ 118	2.44%	$ 120
AES	$ 110	2.44%	$ 112
Algonquin	$ 142	2.44%	$ 146
Alliant	$ 158	2.44%	$ 162
Ameren	$ 70	2.44%	$ 72
Avangrid	$ 69	2.44%	$ 70
Black Hills	$ 173	2.44%	$ 177
CenterPoint	$ 72	2.44%	$ 74
Dominion	$ 58	2.44%	$ 59
Duke	$ 144	2.44%	$ 147
Entergy	$ 222	2.44%	$ 227
Eversource	$ 167	2.44%	$ 171
Exelon	$ 190	2.44%	$ 194
FirstEnergy	$ 56	2.44%	$ 57
Nat Grid	$ 221	2.44%	$ 226
PNM	$ 139	2.44%	$ 142
PPL	$ 129	2.44%	$ 132
Southern Co	$ 87	2.44%	$ 89
Unitil	$ 276	2.44%	$ 283
WEC	$ 162	2.44%	$ 166
Xcel	$ 118	2.44%	$ 121
Group Average	$ 127	2.44%	$ 130

Source: FERC Form 60; Baryenbruch & Company, LLC, analysis

The graph below shows Columbia's average of $153 in post-divestiture NCSC A&G charges per customer to be somewhat higher than the comparison group average $130.

Eight companies, 38% of the comparison group, have a higher cost per-customer than Columbia.



Source: Company information; FERC Form 60; Baryenbruch & Company, LLC, analysis

<u>**Total A&G Expenses per Customer**</u>

Q. What were Columbia's Total 2020 A&G charges per customer?

A. An analysis of Columbia's Total 2020 A&G expenses by Federal Energy Regulatory Commission (FERC) account is shown in Schedule PLB-3. As calculated below, Columbia's total A&G expenses per customer were $282 for 2020.

2020 Columbia Total A&G Expenses per Customer

Columbia Total 2020 A&G Charges	$ 124,279,054
Columbia Customer Count (12/31/2020)	440,651
2020 Total A&G Charges per Customer	$ 282

Source: Company data; Baryenbruch & Company, LLC, analysis

Q. What utilities were included in the total A&G comparison group and where did you obtain their cost information?

A. The comparison group includes 28 utilities in Pennsylvania and neighboring states that filed a Form 1 with the FERC for 2020. Total A&G expenses and customer counts were obtained from the Form 1.

Q. What were the total 2020 A&G expenses per customer for the comparison group utilities?

A. Total A&G expenses per customer for the comparison 28 utility companies are calculated in the table below.

2020	Total A&G Expenses	Total Customers	A&G Expenses per Customer
Appalachian Power Company	$ 141,757,343	960,162	$ 148
Atlantic City Electric Company	$ 211,512,314	562,054	$ 376
Baltimore Gas and Electric Company	$ 271,130,208	1,312,219	$ 207
Central Hudson Gas & Electric Company	$ 145,662,098	244,944	$ 595
Cleveland Electric Illuminating Company	$ 130,066,356	754,024	$ 172
Consolidated Edison Company	$ 1,127,308,671	3,517,291	$ 321
Dayton Power and Light Company	$ 123,162,459	281,989	$ 437
Delmarva Power & Light Company	$ 164,621,296	534,749	$ 308
Duke Energy Ohio, Inc.	$ 69,950,011	731,414	$ 96
Duquesne Light Company	$ 179,124,620	603,791	$ 297
Jersey Central Power & Light Company	$ 283,917,796	1145080	$ 248
Metropolitan Edison Company	$ 124,342,312	577,500	$ 215
Monongahela Power Company	$ 104,852,957	393,758	$ 266
New York State Electric & Gas Corporation	$ 305,860,007	907,336	$ 337
Niagara Mohawk Power Corporation	$ 758,081,544	1,421,431	$ 533
Ohio Edison Company	$ 144,149,065	1,058,301	$ 136
Ohio Power Company	$ 300,154,431	1,501,571	$ 200
Orange and Rockland Utilities, Inc.	$ 125,474,843	236,634	$ 530
PECO Energy Company	$ 369,811,261	1,671,433	$ 221
Pennsylvania Electric Company	$ 122,875,410	587,567	$ 209
Pennsylvania Power Company	$ 29,526,425	168,117	$ 176
Potomac Edison Company	$ 71,199,682	423,085	$ 168
Potomac Electric Power Company	$ 285,006,844	901,712	$ 316
PPL Electric Utilities Corporation	$ 301,897,607	1,457,376	$ 207
Public Service Electric and Gas Company	$ 501,138,768	2,033,919	$ 246
Toledo Edison Company	$ 48,743,376	313,654	$ 155
West Penn Power Company	$ 133,621,851	730,526	$ 183
Wheeling Power Company	$ 10,116,941	41,715	$ 243
Total	$ 6,585,066,496	25,073,352	$ 263

Source: FERC Form 1; Baryenbruch & Company, LLC, analysis

The graph in Schedule PLB-4 shows Columbia's 2020 average of $282 is just above the comparison group average of $263. Ten utilities, 36% of the total comparison group, have a higher 2020 cost than Columbia.

Q. What happens when you factor in the additional $11.4 million in future NCSC allocations due to the divestiture of CMA?

A. If I assume the $11.4 million is made up of the same percent of A&G expenses (91.6% as shown in Schedule PLB-2) as were NCSC's 2020 actual charges, then Columbia's post-divestiture total A&G expenses per customer increases to $306, as calculated below.

Post Divestiture Columbia Total A&G Expenses per Customer

Columbia Total 2020 A&G Charges		$ 124,279,054
Additional NCSC Allocation A&G Charges		
Total Additional Allocation	$ 11,400,000	
2020 Actual A&G Percentage	91.6%	
Additional A&G Amount	$ 10,444,740	$ 10,444,740
Total Post Divestiture A&G Charges		$ 134,723,794
Columbia Customer Count (12/31/2020)		440,651
Post Divestiture A&G Charges per Customer		$ 306

Source: Company data; Baryenbruch & Company, LLC, analysis

Q. What are the comparison group's estimated 2021 total A&G charges per customer?

As shown in the table below, the comparison group's estimated 2021 cost per customer is $269.

The graph in Schedule PLB-5 shows Columbia's 2020 average of $306 somewhat above the comparison group average of $269. Nine utilities, 32% of the total comparison group, have a higher 2020 cost than Columbia.

Q. Do your cost comparisons demonstrate charges from NCSC are reasonable?

A. Yes. I benchmarked the vast majority of NCSC's O&M charges (A&G-related costs make up 91.6% of the total) and found them to be in line with the same charges of other utilities.

On this basis, I can conclude that NCSC's O&M charges to Columbia are reasonable, even considering the additional charges associated with the divestiture of CMA.

Q. Does Mr. Effron present any evidence showing that cost of NCSC services after the divestiture of CMA are unreasonable?

2021 Estimate	2020 Total A&G Expenses per Customer		2021 Estimate Escalation Rate	2021 Estimate Escalated Cost/Customer	
Appalachian Power Company	$	148	2.44%	$	151
Atlantic City Electric Company	$	376	2.44%	$	386
Baltimore Gas and Electric Company	$	207	2.44%	$	212
Central Hudson Gas & Electric Company	$	595	2.44%	$	609
Cleveland Electric Illuminating Company	$	172	2.44%	$	177
Consolidated Edison Company	$	321	2.44%	$	328
Dayton Power and Light Company	$	437	2.44%	$	447
Delmarva Power & Light Company	$	308	2.44%	$	315
Duke Energy Ohio, Inc.	$	96	2.44%	$	98
Duquesne Light Company	$	297	2.44%	$	304
Jersey Central Power & Light Company	$	248	2.44%	$	254
Metropolitan Edison Company	$	215	2.44%	$	221
Monongahela Power Company	$	266	2.44%	$	273
New York State Electric & Gas Corporation	$	337	2.44%	$	345
Niagara Mohawk Power Corporation	$	533	2.44%	$	546
Ohio Edison Company	$	136	2.44%	$	140
Ohio Power Company	$	200	2.44%	$	205
Orange and Rockland Utilities, Inc.	$	530	2.44%	$	543
PECO Energy Company	$	221	2.44%	$	227
Pennsylvania Electric Company	$	209	2.44%	$	214
Pennsylvania Power Company	$	176	2.44%	$	180
Potomac Edison Company	$	168	2.44%	$	172
Potomac Electric Power Company	$	316	2.44%	$	324
PPL Electric Utilities Corporation	$	207	2.44%	$	212
Public Service Electric and Gas Company	$	246	2.44%	$	252
Toledo Edison Company	$	155	2.44%	$	159
West Penn Power Company	$	183	2.44%	$	187
Wheeling Power Company	$	243	2.44%	$	248
Group Average	$	263	2.44%	$	269

A. No. His recommended disallowance appears to be based strictly on his personal opinion that Columbia's NCSC charges should only increase by historical escalation rates (2.44% for 2021 and 2.65% for 2022). He makes no attempt to benchmark NCSC's costs to substantiate his disallowance.

<u>IV. NCSC CHARGES ARE IN LINE WITH THE AIA</u>

Q. Does the AIA provide guidance on the treatment of post-CMA divestiture allocations to Columbia?

A. Yes. The AIA between Columbia and NCSC was approved by the Commission on April 1, 2019. It sets forth the following relevant stipulations:

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with Exhibit A, which is filed annually with the FERC. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed. (AIA, page 3)

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A. (AIA, page 3)

Section 1.3 requires the client (i.e., Columbia) pay for NCSC's full cost for services provided. Post divestiture, NCSC's full cost of services will result in the additional allocation of $11.4 million to Columbia.

Section 2.1 requires that NCSC follow the allocation methods called out in Exhibit A to the AIA. NCSC intends to continue following that allocation methodology post divestiture. They are projected to produce an additional allocation to Columbia of $11.4 million. Thus, NCSC will continue to be in compliance with both sections of the AIA following the divestiture of CMA.

Q. The AIA also calls for NCSC services to be provided at the lower of cost or market. Have you performed work to make that determination?

A. The current AIA between Columbia and NCSC is an update of a prior AIA that the Commission had approved in 2005. When Columbia first presented the updated AIA to the Commission for its approval, the language called for NCSC's services to be provided at cost, without any reference to market. The Commission's Bureau of Technical Utility Services requested that Columbia revise that language to refer to the lower of cost or market. While Columbia initially resisted that revision, Columbia retained me to do an analysis of its NCSC costs for the year ended December 31, 2015. Based upon my analysis, which I completed in April of 2016, I concluded that on average, the hourly rates for outside service providers were 37% higher than comparable hourly rates charged by NCSC to Columbia. I also concluded that if all of the managerial and professional services provided by NCSC had been outsourced in 2015, Columbia and its customers would have incurred $23.5 million in additional expenses. In terms of cost savings, Columbia's costs savings in 2015 alone dwarf the impact of the sale of CMA. When one accounts for inflation, outsourced services would obviously cost more today than they did when I completed my analysis of Columbia's 2015 NCSC costs.

Q. Have you performed an updated study to determine whether NCSC's services are billed to Columbia at the lower of cost or market?

A. I have not performed a market cost comparison on NCSC's 2020 charges to Columbia. However, I have made such a comparison for NCSC's 2020 charges to Columbia Gas of Virginia (CVA), a gas distribution affiliate of Columbia. In May 2021, my report was filed with the Virginia State Corporation Commission along with CVA's annual report on affiliate transactions. I have attached my report to this testimony as Schedule PLB-6. I was able to reach the following conclusions concerning CVA's charges from NCSC:

- NCSC's services were provided to CVA during 2020 at the lower of cost or market.
- On average, the hourly rates for outside service providers are 71% higher than comparable hourly rates charged by NCSC.
- If all of the managerial and professional services now provided by NCSC had been outsourced in 2020, CVA and its customers would have incurred over $19.4 million in additional expenses.
- NCSC charges actual costs of service.

It should be noted that in terms of customers, Columbia's customer count of approximately 440,000 as of December 31, 2020 is much larger than that of CVA, which has a customer count of 279,900. Also, Columbia's O&M-related charges from NCSC are larger than those of CVA. Thus, Columbia's savings from using NCSC would likely be proportionately higher than the $19.4 million CVA realizes.

I have performed a market cost comparison for NCSC charges to CVA for 18 straight years (2003-2020) and have reached the same conclusion in every study. That is, the cost of NCSC's services is far below the cost of outside service providers. I believe this is directly relevant to Columbia's charges from NCSC because the allocation process and factors used to assign NCSC expenses to Columbia and CVA are the same.

V. NCSC CHARGES SHOULD RECEIVE CONSISTENT TREATMENT

Q. How would you describe the growth of NCSC charges to Columbia during the past 5 years?

A. The growth in Service Company charges has been moderate. As shown in the table below, during the 5-year period 2016 to 2020, NCSC charges to Columbia grew by a compound annual growth rate of 2.6%.

Year	Total NCSC O&M Charges to Columbia
2016	$ 56,266,223
2017	$ 68,728,457
2018	$ 63,076,368
2019	$ 64,057,477
2020	$ 62,365,898
Increase	$ 6,099,675
CAGR	2.6%

Q. How much has NiSource's total customer base increased in the past?

A. As shown in the table below, between 2010 and 2019, NiSource's total retail customer base increased by almost 200,000. The additions allowed NCSC's O&M expenses to be allocated over more customers.

Year	Total NiSource Retail Customers at Dec. 31,
2010	3,786,666
2011	3,785,735
2012	3,805,577
2013	3,828,989
2014	3,849,468
2015	3,867,306
2016	3,893,464
2017	3,923,691
2018	3,953,908
2019	3,985,517
Increase	198,851
% Change	5.3%

Q. Do you believe it is equitable for Columbia to recover the additional allocation of NCSC charges related to the divestiture of CMA?

A. Yes. The most equitable outcome is produced by a consistent treatment of the cost of NCSC's services provided to Columbia. In the past, when NiSource's total customer base grew, Columbia's customers received the benefit of economies of scale that flowed through in the form of actual NCSC costs. Columbia did not receive any premium because NCSC's services became relatively less expensive as the enterprise customer base grew. The same treatment should be applied to instances where NiSource's customer base declines. It would be inconsistent for Columbia to be penalized with a disallowance of the NCSC's actual costs of service that have been demonstrated to be reasonable.

VI. THE CUSTOMER BASE OF UTILITIES IS DYNAMIC

Q. Does the retail customer base of utilities owned through a holding company structure experience expansion and contractions?

A. Yes. The retail customer base of utilities owned by a holding company is dynamic, expanding and, sometimes, contracting over time. During the 10 years from 2010 to 2019, NiSource's total regulated retail customers increased 5.3% from 3,786,666 to 3,985,517 through internal growth, as shown in the previous table. Then in October 2020, NiSource's total customer base decreased by 330,639 customers when CMA was sold.

Q. How often do divestitures of regulated retail utility businesses occur?

B. In the past few years, the following regulated utility divestitures have been taken place or are planned to take place:

- PPL Electric sells generation assets to Talen Energy (closed in 2015)
- Southern Company sells Gulf Power to NextEra Energy (closed in 2018; 395,000 retail customers)

- Emera sells Emera Maine to ENMAX (closed in 2020; 159,000 retail customers)
- CenterPoint Energy plans to sell gas distribution business in Arkansas and Oklahoma to Summit Utilities (anticipated close in 2021; 520,000 retail customers)
- American Water plans to sell New York American Water to Liberty Utilities (anticipated close in 2021; 126,000 customers)

In each of these cases, the selling utility holding company owns a service company that continues to provide serves to the remaining regulated utilities affiliates. Thus, the divestiture of CMA and its impact on service company allocations is not an uncommon event in the utility industry.

VII. NCSC SERVICES ARE VITAL AND REMAIN A VALUE TO COLUMBIA

Q. Do you believe services provided in the future by NCSC will continue to benefit Columbia?

A. Yes, Columbia and its customers will continue to benefit from the high-quality services of NCSC, which will remain a good value in the future. In the following excerpt, the AIA clearly recognizes the benefits a service company arrangement provides to regulated utility affiliates.

> *Whereas, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.* (Affiliate Interest Agreement, page 2)

By allowing Columbia to recover its post-divestiture costs-of-service charges from NCSC, the Commission will ensure that Columbia continues to receive the essential services provided by NCSC.

Q. Does this conclude your testimony?

A. Yes,

Patrick Baryenbruch's Previous Affiliate Transactions and Rate Case Engagements

	Client	State	Year	Purpose	Rate Case Witness?
1	Connecticut American Water	Connecticut	1999	Rate Case	Yes
2	Illinois American Water	Illinois	2007	Rate Case	Yes
3	Indiana American Water	Indiana	2017	Rate Case	Yes
4	Iowa American Water	Iowa	2020	Rate Case	Yes
5	Kentucky American Water	Kentucky	2003	Rate Case	Yes
		Kentucky	2006	Rate Case	Yes
		Kentucky	2008	Rate Case	Yes
		Kentucky	2009	Rate Case	Yes
		Kentucky	2018	Rate Case	Yes
6	Massachusetts American Water	Massachusetts	2000	Rate Case	Yes
7	Missouri American Water	Missouri	2002	Rate Case	Yes
		Missouri	2008	Rate Case	Yes
		Missouri	2014	Rate Case	Yes
		Missouri	2016	Rate Case	Yes
		Missouri	2019	Rate Case	Yes
8	New Jersey American Water	New Jersey	2005	Rate Case	Yes
		New Jersey	2007	Rate Case	Yes
		New Jersey	2009	Rate Case	Yes
		New Jersey	2010	Rate Case	Yes
		New Jersey	2014	Rate Case	Yes
		New Jersey	2017	Rate Case	Yes
		New Jersey	2019	Rate Case	Yes
9	New Mexico American Water	New Mexico	2007	Rate Case	Yes
10	New York American Water	New York	2006	Rate Case	Yes
		New York	2010	Rate Case	Yes
		New York	2013	Rate Case	Yes
		New York	2015	Rate Case	Yes
11	Ohio American Water	Ohio	2006	Rate Case	Yes
		Ohio	2010	Rate Case	Yes
12	Pennsylvania American Water	Pennsylvania	2008	Compliance	No
		Pennsylvania	2011	Compliance	No
		Pennsylvania	2014	Compliance	No
		Pennsylvania	2017	Compliance	No
13	Tennessee American Water	Tennessee	2006	Rate Case	Yes
		Tennessee	2010	Rate Case	Yes
14	Virginia American Water	Virginia	1996	Rate Case	Yes
		Virginia	1999	Rate Case	Yes
		Virginia	2000	Rate Case	Yes
		Virginia	2001	Rate Case	Yes
		Virginia	2003	Rate Case	Yes
		Virginia	2007	Rate Case	Yes
		Virginia	2009	Rate Case	Yes
		Virginia	2011	Rate Case	Yes
		Virginia	2014	Rate Case	Yes
		Virginia	2018	Rate Case	Yes
15	West Virginia American Water	West Virginia	2002	Rate Case	Yes
		West Virginia	2006	Rate Case	Yes
		West Virginia	2007	Rate Case	Yes
		West Virginia	2009	Rate Case	Yes
		West Virginia	2012	Rate Case	Yes
		West Virginia	2014	Rate Case	Yes
		West Virginia	2017	Rate Case	Yes
16	Atlanta Gas Light (Southern Co)	Georgia	2009	Rate Case	Yes
17	Atmos Energy Corporation	Virginia	2004	Compliance	No
18	Columbia Gas of Kentucky	Kentucky	2015	Rate Case	Yes
19	Columbia Gas of Maryland	Maryland	2015	Rate Case	Yes
20	Columbia Gas of Massachusetts	Massachusetts	2004	Rate Case	Yes
		Massachusetts	2006	Internal Info	No
		Massachusetts	2011	Internal Info	No
		Massachusetts	2012	Internal Info	No
		Massachusetts	2014	Internal Info	No
		Massachusetts	2017	Internal Info	No

Patrick Baryenbruch's Previous Affiliate Transactions and Rate Case Engagements

	Client	State	Year	Purpose	Rate Case Witness?
21	Columbia Gas of Pennsylvania	Pennsylvania	2015	Rate Case	Yes
22	Columbia Gas of Virginia	Virginia	2003	Compliance	No
		Virginia	2004	Compliance	No
		Virginia	2005	Rate Case	Yes
		Virginia	2006	Compliance	No
		Virginia	2007	Compliance	No
		Virginia	2008	Compliance	No
		Virginia	2009	Rate Case	Yes
		Virginia	2010	Compliance	No
		Virginia	2011	Compliance	No
		Virginia	2012	Compliance	No
		Virginia	2013	Rate Case	Yes
		Virginia	2014	Compliance	No
		Virginia	2015	Rate Case	Yes
		Virginia	2016	Compliance	No
		Virginia	2017	Rate Case	Yes
		Virginia	2018	Compliance	No
		Virginia	2019	Compliance	No
		Virginia	2020	Compliance	No
23	Northern Indiana Public Service	Indiana	2015	Internal Info	No
		Indiana	2016	Rate Case	Yes
24	Dominion Resources, Inc.	Virginia	2008	Rate Case	Yes
		Virginia	2009	Compliance	No
		Virginia	2010	Compliance	No
		Virginia	2011	Compliance	No
		Virginia	2012	Compliance	No
		Virginia	2014	Compliance	No
		Virginia	2017	Compliance	No
		Virginia	2019	Compliance	No
25	Duke Energy	North Carolina	2006	Compliance	No
26	Elizabethtown Gas (Southern Co)	New Jersey	2008	Rate Case	Yes
27	Electric Transmission Texas	Texas	2016	Rate Case	Yes
28	General Water Works of Rio Rancho	New Mexico	1993	Rate Case	Yes
29	General Water Works of Virginia	Virginia	1992	Rate Case	Yes
30	Po River Water and Sewer	Virginia	1993	Rate Case	Yes
		Virginia	2007	Rate Case	Yes
		Virginia	2008	Rate Case	Yes
31	Progress Energy	North Carolina	2001	Internal Info	No
32	Roanoke Gas	Virginia	2006	Compliance	No
33	Southern California Edison	California	2002	Compliance	No
		California	2003	Compliance	No
		California	2004	Compliance	No
		California	2005	Compliance	No
34	AEP Texas	Texas	2018	Rate Case	Yes
35	Southwestern Electric Power	Texas	2016	Rate Case	Yes
		Texas	2020	Rate Case	Yes
36	Virginia Natural Gas (Southern Co)	Virginia	2004	Compliance	No
		Virginia	2005	Rate Case	Yes
		Virginia	2010	Rate Case	Yes
37	United Water of Pennsylvania	Pennsylvania	2004	Rate Case	Yes
38	Corix Infrastructure/Water Services Corp.	Enterprise	2018	Internal Info	No
		Enterprise	2019	Internal Info	No
39	Massanutten Public Service Company	Virginia	2006	Rate Case	Yes
		Virginia	2008	Rate Case	Yes
		Virginia	2013	Rate Case	Yes
		Virginia	2019	Rate Case	Yes
40	Water Service Corporation Kentucky	Kentucky	2010	Rate Case	Yes
		Kentucky	2012	Rate Case	Yes
		Kentucky	2019	Rate Case	Yes
41	Corix Utilities Oklahoma	Oklahoma	2019	Compliance	Yes
42	Great Basin Water Company	Nevada	2020	Rate Case	Yes

Total Studies	123
Number of Rate Cases	83
Number of Utility Clients	41
Number of States	20

Columbia Gas of Pennsylvania, Inc.
Analysis of NCSC A&G Charges to Columbia – 2020

Historical Test Year - 2020 Actual				
	A&G	Operations	Non O&M	Total
Capital and Other Non-O&M Expenditures			$ 23,831,000	$ 23,831,000
Operations and Maintenance Expenses				
807 - Purchased gas expenses		$ 1,194,929		$ 1,194,929
870 - Operation supervision and engineering		$ 2,331,137		$ 2,331,137
874 - Mains and services expenses		$ 367,720		$ 367,720
875 - Measuring and regulating station expenses—General		$ 83,583		$ 83,583
876 - Measuring and regulating station expenses—Industrial		$ 68,386		$ 68,386
878 - Meter and house regulator expenses		$ 309,841		$ 309,841
879 - Customer installations expenses		$ 323,441		$ 323,441
880 - Other expenses		$ 74,448		$ 74,448
887 - Maintenance of mains		$ 93,184		$ 93,184
889 - Maintenance of measuring and regulating station equipment—General		$ 83,552		$ 83,552
890 - Maintenance of measuring and regulating station equipment—Industrial		$ 79,246		$ 79,246
892 - Maintenance of services		$ 38,494		$ 38,494
893 - Maintenance of meters and house regulators		$ 30,782		$ 30,782
894 - Maintenance of other equipment		$ 147,193		$ 147,193
Administrative and General Expenses				
901 - Supervision	$ 4,655,836			$ 4,655,836
903 - Customer records and collection expenses	$ 922			$ 922
908 - Customer assistance expenses	$ 10,940			$ 10,940
909 - Informational and instructional advertising expenses	$ 974,823			$ 974,823
910 - Miscellaneous customer service and informational expenses	$ 21,061			$ 21,061
912 - Demonstrating and selling expenses	$ 321,060			$ 321,060
913 - Advertising expenses	$ 35,622			$ 35,622
920 - Administrative and general salaries	$ 18,225,721			$ 18,225,721
921 - Office supplies and expenses	$ 1,311,905			$ 1,311,905
923 - Outside services employed	$ 21,208,622			$ 21,208,622
924 - Property insurance	$ 2,730			$ 2,730
925 - Injuries and damages	$ 299,453			$ 299,453
926 - Employee pensions and benefits	$ 4,680,548			$ 4,680,548
928 - Regulatory Commission Expenses	$ 31,587			$ 31,587
930.1 - General advertising expenses	$ 69,039			$ 69,039
930.2 - Miscellaneous general expenses	$ 76,629			$ 76,629
931 - Rents	$ 2,333,060			$ 2,333,060
932 - Maintenance of general plant.	$ 2,880,406			$ 2,880,406
Total NCSC Charges to Columbia	$ 57,139,961	$ 5,225,937	$ 23,831,000	$ 86,196,898

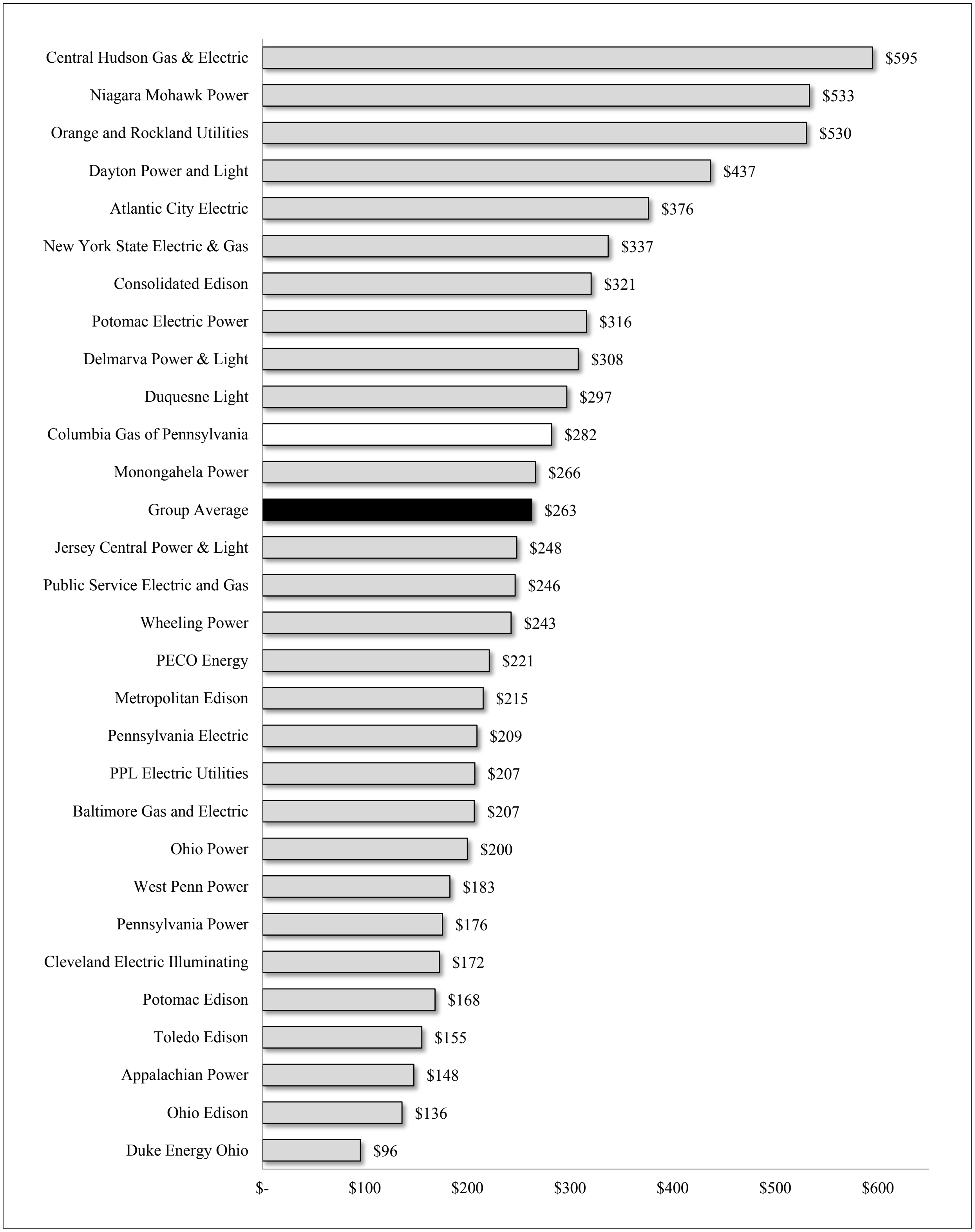
	Percent of Total O&M		
	A&G	Non-A&G	Total O&M
Total 2020, per Above	$ 57,139,961	$ 5,225,937	$ 62,365,898
Percent of Total 2020	91.6%	8.4%	100.0%

Columbia Gas of Pennsylvania, Inc.
Analysis of Total Columbia A&G Expenses – 2020

Account		2020 Actual
90200000	Cust Accnt Meter Reading Exp	609,051
90300000	Cust Records Collection Exp	6,712,939
90400000	Uncollectible Accounts	23,484,843
90500000	Misc Cust Accts Exp	2,597
90800000	Customer Assistance Exp	3,446,010
90900000	Inform_Instruct Advertisng Exp	293,668
91000000	Misc Cust Serv and Info Exp	1,508,476
91100000	Sales Supervision	21,061
91200000	Demonstrating and Selling Exp	321,060
91300000	Sales Advertising Exp	35,622
92000000	A_G Salaries	25,211,753
92001000	Discretionary and Spot Awards	112,027
92002000	Stock Compensation Expense	1,651,844
92100000	Office Supplies and Exp	5,157,568
92101000	Employee Expenses	463,437
92300000	Outside Service Employed	17,560,610
92301000	Mgmt Fee Actuals-Affil	6,958,692
92400000	Property Insurance	137,961
92500000	Injuries and Damages	6,434,762
92600000	Employee Pensions and Benefits	15,184,399
92601000	Non Service Pension & OPEB	(2,859,373)
92800000	Regulatory Commission Exp	2,715,434
93010000	General Advertising Exp	323,016
93020000	Misc General Exp	709,345
93100000	Rents Admin and General	4,800,299
93200000	Maint General Plant	3,281,423
93500000	Maint General Plant Electric	530
99000001	Gross Payroll Hyperion	31,550,517
99000004	Management Fee Hyperion	82,448
99900001	Gross Pay Offset Hyperion	(31,550,517)
99900002	Mgmt Fee Offset Hyperion	(82,448)
Total Columbia 2020 A&G Expenses		124,279,054

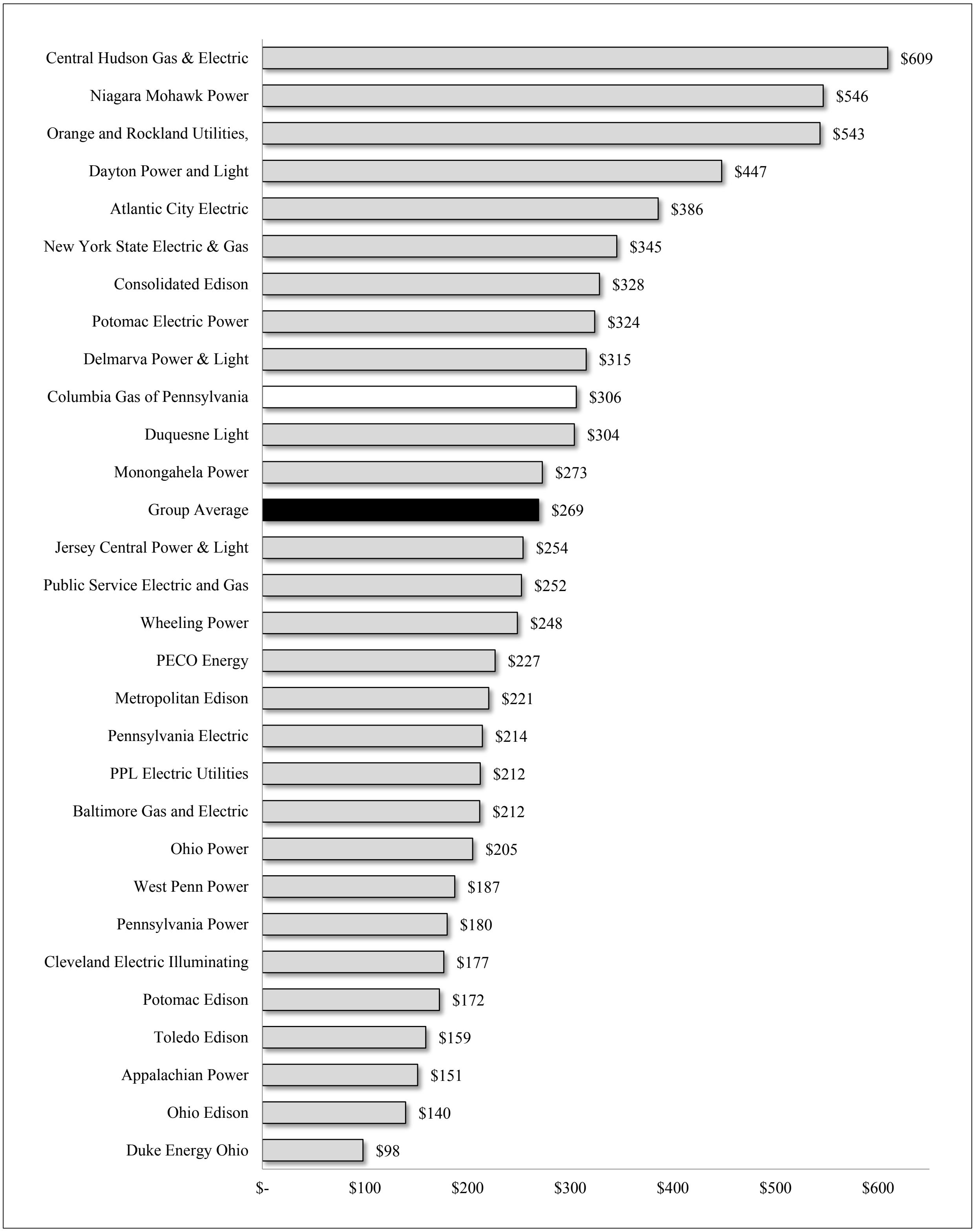
Source: Company information

Columbia Gas of Pennsylvania, Inc.
Comparison of 2020 Total A&G Expenses Per Customer



Source: FERC Form 1; Baryenbruch & Company, LLC Analysis

Columbia Gas of Pennsylvania, Inc.
Comparison of Estimated 2021 Total A&G Expenses Per Customer



Source: FERC Form 1; Baryenbruch & Company, LLC Analysis

Columbia Gas of Virginia, Inc.

Market Cost Comparison for Affiliate Company Charges
12 Months Ended December 31, 2020

April 2021

Baryenbruch & Company, LLC

Columbia Gas of Virginia, Inc.
Market Cost Comparison for Affiliate Company Charges
12 Months Ended December 31, 2020

Table of Contents

Purpose of This Study

This study was undertaken to determine the reasonableness of Columbia Gas of Virginia, Inc.'s, (CVA) charges from NiSource Corporate Services Company (NCSC) and several NiSource operating companies for services provided during 2020. Reasonableness was determined by answering the following three questions:

1. Are affiliates' 2020 administrative and general (A&G) charges to CVA reasonable compared to other utility service companies?
2. Did NCSC provide services to CVA at the lower of cost or market during 2020?
3. Is the 2020 cost of NCSC's customer accounts services comparable to that of other utilities?

Study Results

Conclusions concerning question 1:

- The 2020 cost per CVA customer for A&G services from NCSC and other affiliates is reasonable compared to the costs per customer for similar utility service companies. CVA was charged an average of $103 per customer for these services by affiliates. This amount is lower than the average of $114 per customer for comparison group service companies. CVA's $103 annual cost is lower than 12 of the 22 comparison group service companies. This determination was based on service company information included in Form 60, which must be annually filed with the Federal Energy Regulatory Commission (FERC) by utility holding companies.

Conclusions concerning question 2:

- NCSC's services were provided to CVA during 2020 at the lower of cost or market.
- On average, the hourly rates for outside service providers are 71% higher than comparable hourly rates charged by NCSC.
- If all of the managerial and professional services now provided by NCSC had been outsourced in 2020, CVA and its customers would have incurred over $19.4 million in additional expenses.
- NCSC charges actual costs of service.

Conclusions concerning question 3:

- CVA's customer accounts services costs, which include charges from NCSC and other affiliates, are well below the average of the utility comparison group from Virginia and neighboring states. During 2020, CVA's customer accounts services cost per customer was $18.53 compared to the utility comparison group's 2019 average of $32.93. CVA's average of $18.53 is lower than 13 of the 15 comparison group utilities.

This study's results show that CVA's 2020 service-related charges from NCSC and other affiliates are reasonable. The following pages elaborate on the research and findings supporting these results.

Overview of CVA Affiliate Company Services

NCSC provides the following types of services to NiSource Inc., operating companies, including CVA:

Accounting and Statistical Services	Gas Dispatching Services
Auditing Services	Information Services
Budget Services	Information Technology Services
Business Services	Insurance Services
Corporate Services	Land/Surveying Services
Customer Billing, Collection and Contact	Legal Services
Services	Officers
Depreciation Services	Operations Support and Planning Services
Economic Services	Purchasing, Storage and Disposition Services
Electronic Communications Services	Regulatory Services
Employee Services	Tax Services
Engineering and Research Services	Transportation Services
Facility Services	Treasury Services

NCSC Billings to Affiliate Companies

NCSC was regulated by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA) until February 8, 2006, when the Public Utility Holding Company Act (PUHCA 2005) was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to the Federal Energy Regulatory Commission (FERC). NCSC records transactions in accordance with the FERC Uniform System of Accounts.

Pursuant to FERC Order No. 684 issued October 19, 2006, Centralized Service Companies 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. NCSC has long used a billing pool system to collect costs that are applicable and billable to all affiliates, including CVA. Each billing pool details the affiliate(s) to be charged for the specified services and the basis for allocating charges when more than one affiliate receives the same service.

The service agreement between CVA and NCSC stipulates that all services will be provided at cost, including compensation for use of capital. Allocations among affiliates are only made when it is impractical to charge an affiliate directly.

The Bases of Allocation, shown in Schedule 1, are used by NCSC Accounting Department for apportioning charges to affiliates.

Columbia Gas of Virginia, Inc.

Bases for Allocating Service Company Charges to Affiliates

Basis 1 - Gross Fixed Assets and Total Operating Expenses Fifty percent of the total charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating
Basis 2 - Gross Fixed Assets Charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be
Basis 3 - Number of Meters Serviced Charges will be allocated to each benefited affiliate on the basis of the relation of its number of meters serviced to the total number of all meters serviced of the benefited affiliates. This allocation may only be used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas
Basis 4 - Number of Accounts Payable Invoices Processed Charges will be allocated to each benefited affiliate on the basis of the relation of its number of accounts payable invoices processed (interface invoices excluded) to the total number of all accounts payable invoices processed of the benefited affiliates. All companies may be included in this
Basis 7 - Gross Depreciable Property and Total Operating ExpensesFifty percent of the total charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited
Basis 8 - Gross Depreciable Property Charges will be allocated to each benefited affiliate on the basis of the relation of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be
Basis 9 - Automobile Units Charges will be allocated to each benefited affiliate on the basis of the relation of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies
Basis 10 - Number of Retail CustomersCharges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the
Basis 11 - Number of Regular Employees Charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may
Basis 13 - Fixed Allocation Charges will be allocated to each benefited affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.
Basis 14 - Number of Transportation Customers Charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas
Basis 15 - Number of Commercial Customers Charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia
Basis 16 - Number of Residential Customers Charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia
Basis 17 - Number of High Pressure Customers Charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia
Basis 20 - Service Company Billing (Direct and Allocated) Charges will be allocated to each benefited affiliate on the basis of the relation of its Service Corporation billing costs, in total or by functional group (e.g. IT, Legal, HR, Finance, Audit), to the corresponding total of all Service Company billing costs, (i.e. in total or by functional group). The calculation of Basis 20 will include only those billings for services provided to all NiSource affiliates, excluding Business Unit specific shared service functions (i.e. functions that serve only one particular

Service Agreements with Affiliates

Transactions between CVA and affiliates are covered by the service agreements shown in the table below:

Type of Services	Affiliate	Agreement Date	VSCC Approving Order	Where Reported in CVA's Annual Report of Affiliate Transactions
Coporate Support Services - Office Space and Support (Pass Through Costs)	NiSource Corporate Services	Jan 1, 2015	PUR-2019-00143	Exhibits C,D Exhibit O
Shared Services	Columbia Gas of Ohio	Oct 1, 2016	PUE-2016-00075	Exhibits E, F, H, I
	Columbia Gas of Pennsylvania	Oct 1, 2016	PUE-2016-00075	Exhibits E, F, H, I
	Columbia Gas of Kentucky	Oct 1, 2016	PUE-2016-00075	Exhibits E, F, H, I
	Columbia Gas of Maryland	Oct 1, 2016	PUE-2016-00075	Exhibits E, F, H, I
Shared Services	Columbia Gas of Massachusetts	May 1, 2016	PUE-2016-00008	Exhibits E, F, H, I
Shared Services	Northern Indiana Public Service	Sep 1, 2018	PUR-2018-00114	Exhibits E, F, H, I
Meter Exchange	Columbia Gas of Ohio	Aug 1, 2018	PUR-2018-00071	Exhibits E, F, H, I
	Columbia Gas of Pennsylvania	Aug 1, 2018	PUR-2018-00071	Exhibits E, F, H, I
	Columbia Gas of Kentucky	Aug 1, 2018	PUR-2018-00071	Exhibits E, F, H, I
	Columbia Gas of Maryland	Aug 1, 2018	PUR-2018-00071	Exhibits E, F, H, I
Gas Supply and Other Supply-Related Contracts	Columbia Gas of Ohio	Apr 1, 2002	PUR-2018-00040	Exhibits E, F, H, I
	Columbia Gas of Pennsylvania	Apr 1, 2002	PUR-2018-00040	Exhibits E, F, H, I
	Columbia Gas of Kentucky	Apr 1, 2002	PUR-2018-00040	Exhibits E, F, H, I
	Columbia Gas of Maryland	Apr 1, 2002	PUR-2018-00040	Exhibits E, F, H, I
	Columbia Gas of Massachusetts	Apr 1, 2002	PUR-2018-00040	Exhibits E, F, H, I
Intercompany Financing	NiSource Inc., NiSource Corporate Services and Eligible Borrowers	Nov 30, 2017	PUR-2020-00257	Exhibit A
Office Space and Support	NiSource Corporate Services	May 24, 2002	PUA-2002-00013	Exhibit I
Income Tax	Affiliates of Consolidated Group	Mar 27, 2020	PUR-2020-00059	Exhibit P

Corporate support services provided by NCSC to CVA are set forth in a service agreement dated January 1, 2015, which was approved by the VSCC by an order dated November 25, 2019. The agreement is authorized for a period of five years through December 31, 2025.

Shared services agreements exist between CVA and the following operating company affiliates. Services provided under these agreements are priced at cost.

- Columbia Gas of Kentucky
- Columbia Gas of Maryland
- Columbia Gas of Massachusetts
- Columbia Gas of Ohio
- Columbia Gas of Pennsylvania
- Northern Indiana Public Service Company.

Analysis of CVA Charges from Affiliates

During 2020, the following affiliate entities charged CVA approximately $130.8 million:

Affiliate Entity		2020
NiSource Gas Distribution Group		
NiSource Corporate Services	$	107,344,326
Columbia Gulf Transmission	$	-
Columbia Network Services		
Columbia Gas of Kentucky	$	6,117
Columbia Gas of Ohio	$	171,919
Columbia Gas of Maryland	$	79,811
Columbia Gas of Pennsylvania	$	550,149
Columbia Gas of Massachusetts	$	14,142
Columbia Gas Transmission	$	-
Columbia Network Services	$	-
NiSource, Inc.	$	22,211,302
Northern Indiana Public Service	$	15,876
NiSource Finance	$	-
NiSource Money Pool	$	395,481
Total	$	130,789,123

NCSC bills CVA for its costs to render the services that are agreed upon in the Service Agreement. These expenses may be charged directly or allocated, depending upon the nature of the services. NCSC also bills CVA for pass-through expenses that fall into the following categories:

- Convenience Billings – On behalf of affiliates like CVA, NCSC pays for charges from third party providers of services. These charges are considered “pass-through” costs, flowing through NCSC to affiliates for their convenience and benefit. Typical charges include external audit fees, employee benefits, vehicle leasing and corporate insurance.

- Payroll Funding – NCSC funds the payroll disbursement bank account for all NiSource Inc. subsidiaries. Each subsidiary, including CVA, reimburses NCSC for its portion of the payroll funding.

- Employee Expense Funding – NCSC funds the bank account that makes disbursements for employee expense reimbursements. Each subsidiary, including CVA, reimburses NCSC for its portion of the funded amounts.

NiSource Inc., charged CVA for interest expense on CVA’s portion of long-term debt issued by NiSource Inc. NiSource Money Pool charged for interest expense on CVA’s net short-term borrowings from the corporate-wide money pool. Other Columbia Gas operating companies periodically share resources to perform construction, maintenance and other operational activities. This sharing arrangement is meant to reduce the cost of service for all customers.

Certain affiliate billings to CVA are service-related and can be subjected to a market-to-actual-cost comparison. The table below shows the charges to CVA during 2020 by type of transaction. Interest expenses on CVA borrowings from NiSource Inc., and the money pool do not involve the provision of services. Convenience billings, payroll funding and employee expense funding represent the pass-through of actual expenses paid by NCSC on CVA's behalf and also do not involve the provision of services.

		Cost Comparison Testing Disposition		
Type of Transaction	2020 Affiliate Charges To CVA	Involves A Service?	Comparative Data Available?	Evaluated In This Study?
Interest on Debt and Taxes	$ 22,162,980	No	na	No
Convenience Billings and Payroll	$ 60,219,303	No	na	No
Contract Services	$ 47,125,023	Yes	Yes	Yes
Billings From Other Affiliates - Balance Sheet Accts	$ 672,935	Limited	No	No
Billings From Other Affiliates - Income Statement Accts	$ 608,882	Limited	Yes	Yes
Total Affiliate Company Billings	**$ 130,789,123**			

Contract Services represent charges for NCSC management, professional and technical services. They can be subjected to a market-to-actual cost analysis for which comparative information is available. These charges, therefore, are included in the scope of this study.

Much of the total $672,935 in Billings from Other Affiliates – Balance Sheet is for construction costs (materials and outside services) charged primarily by Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Massachusetts. The large majority of these charges (approximately $529,900) are for materials, outside services and other expenses associated with construction activities. Around $51,600 was labor-related for the management and oversight of certain shared construction activities. No publicly available market information was found for outside providers of construction services. Thus, this study did not subject these 2020 charges to a cost comparison.

Much of the total $608,882 in Billings from Other Affiliates - Income Statement are for various operational services. Approximately $194,500 of these charges were for labor-related services, primarily for regulatory compliance and customer service-related support activities. Here too, it is difficult to find publicly available market information for outside providers of these services. Also, included in Billings from Other Affiliates – Income Statement are charges from NCSC for incentive compensation and NiSource Inc., for long-term incentive awards and employee stock purchase plan costs. These charges do not involve a service.

Comparison Methodology for Service-Related Affiliate Billings

2020 affiliate charges that are included in the scope of this study are evaluated in connection with three questions, as shown in the table below.

Type of Transaction	2020 Affiliate Charges To CVA	Study Question: 1 - Reasonableness	Study Question: 2 - LCM Pricing	Study Question: 3 - Cust Acct Svcs
Contract Services	$ 47,125,023	X	X	X
Billings From Other Affiliates - Income Stmt Accts	$ 608,882	X		X
Total (A)	$ 47,733,905			

Note A: Billings to Other Affiliates - Income Stmt Accts is netted against these charges for purposes of calculating A&G-related charges per customer

The first question—whether affiliate charges for A&G services are reasonable—is answered by comparing CVA's 2020 affiliate charges per customer to those of utility service companies that file a FERC Form 60 – Annual Report of Service Companies. This comparison was made with data from 2019, the latest year Form 60 data is available (the filing deadline for the Form 60 is generally May 1st).

The second question—whether NCSC's services were provided to CVA during 2020 at the lower of cost or market—is answered by comparing the cost per hour for managerial and professional services provided by NCSC personnel to hourly billing rates that would be charged by outside providers of equivalent services. NCSC's costs per hour were based on actual charges to CVA during 2020. Outside providers' billing rates came from surveys or other information from professionals who could perform the services now provided by NCSC.

The third question—whether affiliate customer account services charges were comparable to other utilities—is answered by comparing CVA's total 2020 expenses for customer accounts services to those of comparison group utilities in Virginia and neighboring states. Comparison group expense information was obtained from FERC Form 1 data. The comparison was made using 2019 data, the latest year for which FERC Form 1 data is available (the filing deadline for FERC Form 1 is April 18th).

Analysis of CVA Charges to Affiliates

CVA charged affiliates around $0.8 million during 2020, as shown below:

	2020 Charges From CVA
Billings to Other Affiliates - Balance Sheet Accounts	$ 298,711
Billings to Other Affiliates - Income Statement Accounts	$ 488,521
Total Charges To Affiliates	$ 787,232

Most Balance Sheet-related billings to affiliates consist of construction work CVA performed for affiliate operating companies. During 2020, CVA also provided to other operating companies affiliate management and oversight of certain shared construction activities. Approximately $104,500 of charges to these other affiliates were labor-related.

Income Statement-related billings consist of building lease and maintenance expenses and charges for a variety of services CVA provided to affiliate operating companies, primarily CMA. Included in the category of Income Statement-related billings to affiliates is approximately $309,900 that NCSC paid CVA to cover lease and maintenance expenses for its employees located in buildings throughout CVA's service territory.

CVA charges its fully loaded cost of labor for work it performs for affiliates. No market testing was performed on 2020 charges to affiliates because fully loaded costing is the pricing method called for in service agreements CVA has with affiliates.

CVA's Cost per Customer

During 2020, CVA was charged $103 per customer for A&G services provided by NCSC and other affiliates, as calculated below.

2020	A&G	Non-A&G	Total
Capital and Other Non-O&M Expenditures		$ 12,071,761	$ 12,071,761
Operations and Maintenance Expenses			
403 - Depreciation expense		$ 1,494,415	$ 1,494,415
404 - Amortization expense		$ 21,715	$ 21,715
405 - Amortization of other property		$ 1,017,295	$ 1,017,295
408 - Taxes other than income taxes		$ 1,012,113	$ 1,012,113
409 - Income taxes		$ 146,074	$ 146,074
410 - Provision for deferred income taxes		$ 928,868	$ 928,868
411 - Provision for deferred income taxes—credit		$ (1,074,943)	$ (1,074,943)
419 - Interest and dividend income		$ (138)	$ (138)
421 - Miscellaneous income or loss		$ (38,910)	$ (38,910)
426 - Other deductions		$ 17,236	$ 17,236
430 - Interest on debt to associate companies		$ 214,840	$ 214,840
431 - Other interest expense		$ 73,443	$ 73,443
432 - Allowance for borrowed funds used during construction—Credit		$ (58,005)	$ (58,005)
807 - Purchased gas expenses		$ 719,869	$ 719,869
870 - Operation supervision and engineering		$ 1,618,053	$ 1,618,053
874 - Mains and services expenses		$ 185,884	$ 185,884
875 - Measuring and regulating station expenses—General		$ 29,056	$ 29,056
876 - Measuring and regulating station expenses—Industrial		$ 23,773	$ 23,773
878 - Meter and house regulator expenses		$ 150,391	$ 150,391
879 - Customer installations expenses		$ 144,842	$ 144,842
880 - Other expenses		$ 33,220	$ 33,220
887 - Maintenance of mains		$ 76,875	$ 76,875
889 - Maintenance of measuring and regulating station equipment—General		$ 29,035	$ 29,035
890 - Maintenance of measuring and regulating station equipment—Industrial		$ 28,520	$ 28,520
892 - Maintenance of services		$ 44,219	$ 44,219
893 - Maintenance of meters and house regulators		$ 7,945	$ 7,945
894 - Maintenance of other equipment		$ 63,831	$ 63,831
Administrative and General Expenses			
903 - Customer records and collection expenses	$ 2,778,000		$ 2,778,000
908 - Customer assistance expenses	$ 3,938		$ 3,938
910 - Miscellaneous customer service and informational expenses	$ 836,673		$ 836,673
911 - Supervision	$ 13,229		$ 13,229
912 - Demonstrating and selling expenses	$ 3,276		$ 3,276
913 - Advertising expenses	$ 22,919		$ 22,919
920 - Administrative and general salaries	$ 10,475,366		$ 10,475,366
921 - Office supplies and expenses	$ 768,042		$ 768,042
923 - Outside services employed	$ 7,321,066		$ 7,321,066
924 - Property insurance	$ 1,391		$ 1,391
925 - Injuries and damages	$ 160,090		$ 160,090
926 - Employee pensions and benefits	$ 2,766,042		$ 2,766,042
928 - Regulatory commission expenses	$ 273		$ 273
930 - Miscellaneous general expenses	$ 88,779		$ 88,779
931 - Rents	$ 1,331,986		$ 1,331,986
932 - Maintenance of general plant.	$ 1,572,674		$ 1,572,674
Total NCSC Charges	$ 28,143,745	$ 18,981,277	$ 47,125,023
A&G Charges from Other Affiliates			
Columbia Gas of Kentucky	$ 104		
Columbia Gas of Ohio	$ 12,956		
Columbia Gas of Maryland	$ 143		
Columbia Gas of Pennsylvania	$ 239,774		
Columbia Gas of Massachusetts	$ 254,560		
NiSource, Inc.	$ 4,260		
Total A&G Charges from Other Affiliates	$ 511,798		
Total Affiliate A&G Charges	$ 28,655,543		
2020 CVA Customers	278,924		
2020 NCSC A&G Charges per CVA Customer	**$ 103**		

Comparison Group Cost per Customer

Every centralized service company in a holding company system subject to regulation by the FERC must file a Form 60 in accordance with the Public Utility Holding Company Act of 2005, Section 1270, Section 390 of the Federal Power Act and 18 C.F.R. paragraph 366.23. This report is designed to collect financial information from service companies that are subject to regulation by the FERC.

For 2019, a Form 60 was filed by service companies associated with 22 utility companies (excluding NCSC), all of which provide regulated utility services to customers. In order to make a valid comparison of this group's costs to those of NCSC charges to CVA, it was necessary to isolate expenses that they have in common. These include A&G-related charges associated with the following FERC accounts:

903 – Customer records and collection expenses	923 – Outside services employed
908 – Customer assistance expenses	924 – Property insurance
909 – Info & instructional advertising materials	925 – Injuries and damages
910 – Misc customer service and info expenses	926 – Employee pensions and benefits
911 – Supervision	930.1 – General advertising
912 – Demonstrating and selling expenses	930.2 – Miscellaneous general expenses
913 – Advertising expenses	931 – Rents
920 - Administrative and general salaries	935 – Maintenance of structures and equipment
921 – Office supplies and expenses	

Charges to utility affiliates for the comparison group service companies were obtained from Schedule XVI – Analysis of Charges for Service Associate and Non-Associate Companies (p. 303 to 306) of each entity's FERC Form 60. This schedule shows charges by FERC Account.

The 2019 expenses for comparison group service companies were adjusted to remove charges to non-regulated affiliates from the cost pool used to calculate the cost per regulated service customer. This determination was made using information from the FERC Form 60 schedule: Account 457 – Analysis of Billing – Associate Companies.

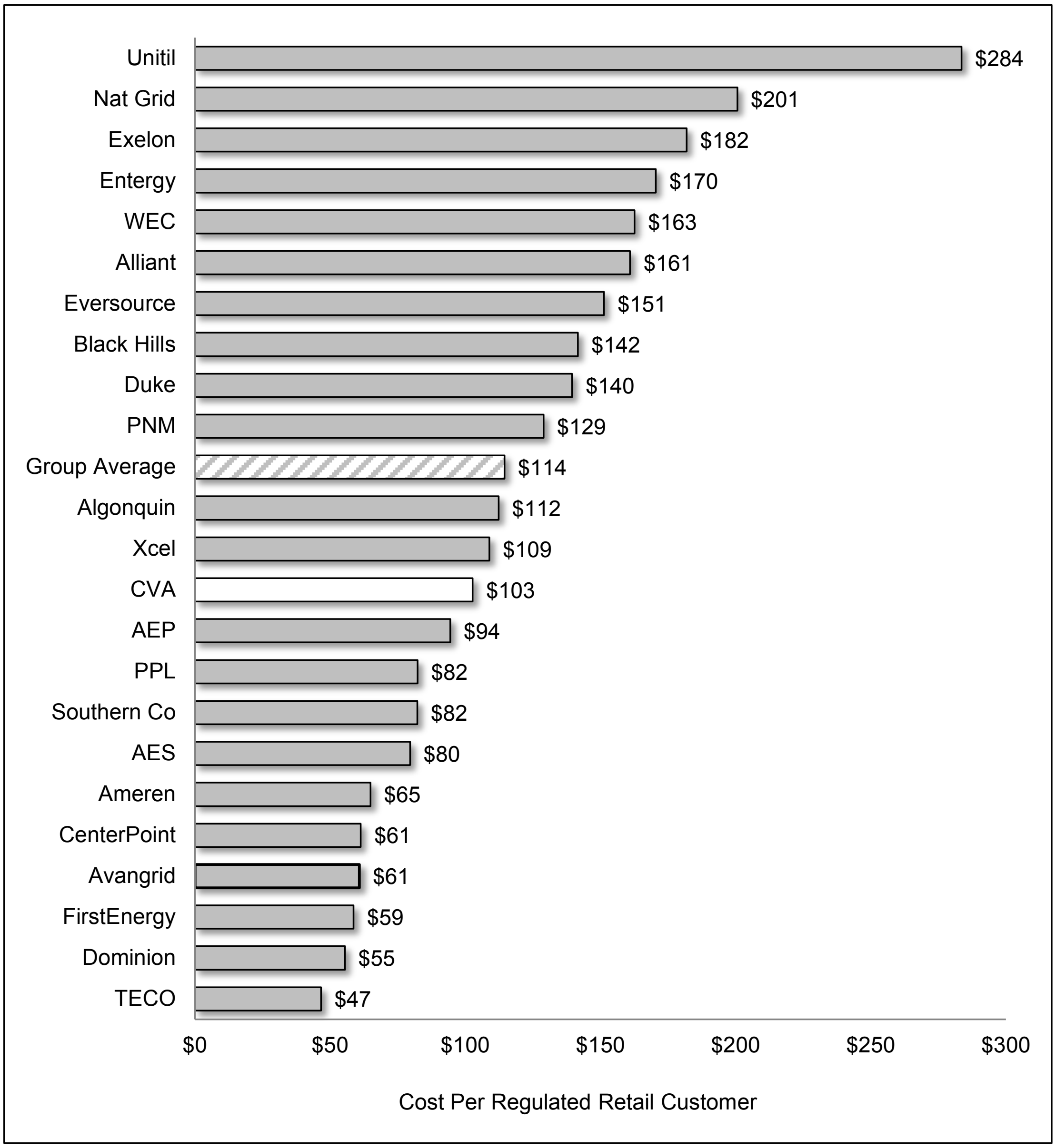
NCSC filed a Form 60, but it is not included in this comparison because only its charges to CVA are the subject of this cost comparison. The A&G expenses per regulated utility customer for the other 22 utility companies that filed a Form 60 for 2019 are calculated in the table below.

Utility Company	2019 Regulated Retail Service Company A&G Expenses	Regulated Retail Customers	Cost per Customer
AEP	$519,398,349	5,500,000	$ 94
AES	$61,627,317	774,742	$ 80
Algonquin	$67,273,995	599,000	$ 112
Alliant	$223,494,744	1,388,623	$ 161
Ameren	$214,257,630	3,300,000	$ 65
Avangrid	$197,721,346	3,250,000	$ 61
Black Hills	$181,304,008	1,280,000	$ 142
CenterPoint	$406,323,112	6,624,496	$ 61
Dominion	$371,609,377	6,700,000	$ 55
Duke	$1,269,616,108	9,100,000	$ 140
Entergy	$528,472,572	3,100,000	$ 170
Eversource	$551,238,793	3,643,000	$ 151
Exelon	$1,818,488,048	10,000,000	$ 182
FirstEnergy	$351,956,860	6,000,000	$ 59
Nat Grid	$1,404,211,190	7,000,000	$ 201
PNM	$101,712,212	788,826	$ 129
PPL	$222,406,974	2,700,000	$ 82
Southern Co	$703,140,288	8,547,000	$ 82
TECO	$78,263,935	1,678,000	$ 47
Unitil	$53,886,249	190,040	$ 284
WEC	$377,059,692	2,319,000	$ 163
Xcel	$620,857,771	5,700,000	$ 109
Total	**$10,324,320,568**	**90,182,727**	**$ 114**

Source: FERC Form 60; Baryenbruch & Company, LLC, analysis

Schedule 2 shows that CVA's 2020 NCSC and other affiliate A&G charges per customer of $103 are lower than the average of $114 per customer for the comparison group service companies. CVA's 2020 $103 per customer A&G charges is lower than 12 of the 22 comparison group service companies. Based on this result, it can be concluded that NCSC's 2020 charges to CVA are reasonable.

Columbia Gas of Virginia, Inc.
Comparison of Service Company Annual A&G Charges Per Customer



Source: Company information; FERC Form 60; Baryenbruch & Company, LLC, analysis

Methodology

NCSC's 2020 billings to CVA for corporate services are market tested by comparing the cost per hour for NCSC services to those of outside service providers to whom these duties could be assigned.

The first step was to determine which types of outside providers could assume Service Company services. Based on the nature of these services it was determined that the following outside service providers could perform the categories of services indicated:

- Attorneys - corporate secretarial and legal services
- Certified Public Accountants - accounting, finance and rates and regulatory services
- Professional Engineers – engineering and operations services
- Management Consultants - executive and administrative management, risk management services, human resources and communications services
- Information Technology (IT) Professionals – information technology services

The next step was to calculate NCSC's hourly rate for each of the five outside service-provider categories, based on the dollars and hours charged to CVA during 2020. Next, hourly billing rates for outside service providers were determined using information from pertinent surveys. Finally, NCSC's average cost per hour was compared to the average cost per hour for outside providers.

NCSC Hourly Rates

The first step in determining NCSC's hourly rates is to designate the appropriate expenses to be included in the calculation. As shown in Schedule 3, certain NCSC contract billings-related charges were excluded from the hourly rate calculations. Excluded cost elements include charges that are, in effect, already outsourced (e.g., IT services outsourcing, outside services expenses) or items that outside providers would not typically recover in their hourly rates (e.g., travel expenses, enterprise-wide IT infrastructure expenses, operational/non-services related expenses). Also excluded are the costs of the Smithfield call center whose services are not provided by traditional professional services firms. The net result of these adjustments is the total applicable cost pool that is subjected to the lower-of-cost-or-market testing.

Columbia Gas of Virginia, Inc.
Analysis of 2020 Testable NCSC Contract Billings

2020 Total Contract Billings from NCSC to CVA		$ 47,125,023
Less Excludable Cost Elements		
Contract Services		
3000 - Consulting Services	$ 4,169,417	
3001 - Advertising Services	$ 58,391	
3002 - Legal Services	$ 265,605	
3003 - Auditing Services	$ 10,189	
3004 - Construction Services	$ 255,560	
3006 - Engineering Services	$ 159,746	
3008 - Printing and Fulfillment Svcs	$ 79,354	
3009 - Operations Services	$ (595)	
3011 - Temporary Personnel Services	$ 265,411	
3012 - Security Services	$ 165,438	
3015 - Other Outside Services	$ 40,505	
3021 - Env Health and Safety Services	$ 288,880	
3022 - Generation Constr Maint Svcs	$ 54	
3024 - Benefit Administration	$ 91,937	
3025 - Credit Collections	$ 517	
3027 - Cash Processing	$ 27,492	
3028 - Expert Witness Fees	$ 1,170	
3030 - Outsourcing - Est Fixed Costs	$ (1,131)	
3031 - Outsourcing-Variable Cst-ARCs	$ 1,531,040	
3036 - Service Level Agreements	$ 8,501	
3037 - Miscellaneous Reimbursements	$ 242,591	
3040 - Outsourcing - Act Fixed Costs	$ 217,026	
3044 - IT Costs - Non-IBM Contract	$ 656,537	
3046 - HR Services	$ 130,181	
3047 - IT Services	$ 2,616,717	
3093 - Operations Mapping Srvcs - GPS	$ (4,760)	
IT Infrastructure		
2500 - IT Hardware	$ 23,476	
2501 - IT Software	$ 1,362,718	
5004 - IT Software Maintenance	$ 1,798,387	
5009 - IT Hardware Maintenance	$ 77,456	
9310 - Other Depreciation	$ 1,818,730	
Travel Expenses		
3100 - Business Travel Expenses	$ 216,791	
3102 - Meals, Food and Water	$ 83,406	
3103 - Entertainment & Other Non-Ded	$ 4,886	
3105 - Taxable Business Exp-ERS Only	$ 26	
5003 - Aircraft Maintenance	$ (3,918)	
5020 - Vehicle Maintenance	$ 99,131	
9230 - Leases - Aircraft	$ 34,008	

Columbia Gas of Virginia, Inc.
Analysis of 2020 Testable NCSC Contract Billings

Less Excludable Cost Elements (cont.)			
Operational/Non-Service Expenses			
2012 - Bulk Materials	$	8	
2017 - Other Materials and Supplies	$	555,784	
2023 - Instrumentation & Control	$	504	
2024 - Mechanical Equipment	$	37,705	
2203 - Other Gas Materials and Equip	$	699	
3619 - AR Customer Refunds	$	1,638	
3825 - Other-Compliance_ etc	$	14,632	
4017 - Losses_Claims Expense	$	14,751	
4503 - AFUDC_IDC - Debt	$	(58,005)	
4508 - Gain-Loss on Sale	$	(1,356)	
4533 - PP Man Acc Excl Int_OH	$	225,640	
5013 - Garbage and Waste Disposal	$	1,724	
5014 - Lot Maintenance	$	3,500	
5030 - Truck Maintenance	$	6,630	
5040 - Tool Maintenance	$	2,676	
9210 - Leases - Vehicles	$	7,629	
9261 - Overheads Related To Lse-Rent	$	294,958	
9604 - Income Taxes Federal	$	111,944	
9605 - Income Taxes State	$	34,131	
9606 - Deferred Income Taxes Federal	$	(283,772)	
9607 - Deferred Income Taxes State	$	137,697	
9610 - Sales and Use Tax	$	32,827	
9640 - Sales_Use - Audit Reserve	$	12,177	
Total Excludable Cost Elements			$ 17,944,991
Less Excludable Departments			
0005000 Aviation Services	$	87,628	
0030310 Smithfield Customer Care Centr	$	1,665,789	
0042800 Cost of Capital	$	214,702	
Total Excludable Departments			$ 1,968,119
2020 Testable Contract Billings from NCSC (Note A)			$ 27,211,913
Note A: This total breaks down as follows for later analysis:			
Service-Related Charges			$ 23,556,170
Overhead-Related Charges			$ 3,655,744
2020 Testable Contract Billings from NCSC			$ 27,211,913

The next step was to assign NCSC's service-related charges to cost pools for the five outside service providers—attorney, certified public accountant, engineer, management consultant and IT professional. Among other things, NCSC designates the charging department for all affiliate charges. Based on the nature of services performed by these departments, NCSC's charges were assigned to cost pools for the five outside service providers as shown in Schedule 4 (page 18).

Schedule 5 (page 19) shows the assignment of NCSC department staff hours to cost pools for the five outside service providers. It should be noted that only professional personnel hours are included in Schedule 5. Many outside providers charge clients for the time of administrative support personnel (e.g., paralegals). This study chose to be conservative in this regard. By excluding administrative personnel hours from the hourly rate denominator, there are fewer hours to divide into the cost pool. Consequently, NCSC's hourly rates are somewhat higher using this approach.

Within the total 2020 NCSC charges are overhead-related items associated with sustaining NCSC personnel. 2020 amounts by department are shown below. These expenses would also be incurred by outside service providers and are added into the NCSC cost pools.

Department/Cost Element	2020
Cell Phones	$ 85,246
Corporate Services	$ 15,765
Facilities Management	$ 223,643
Facility Rent	$ 1,404,948
Hardware Depreciation	$ 714,695
Long Term Incentive Expense	$ 689,542
Insurance Premiums	$ 148,164
Mailing Operations	$ 208,867
Real Estate	$ 161,721
Telecommunications	$ 3,106
Other	$ 47
Total Overhead	$ 3,655,744

Based on the assignment of expenses and hours to outside provider categories, NCSC's 2020 equivalent cost per hour is calculated below.

	NCSC Hourly Rates					
	Attorney	Certified Public Accnt	Professional Engineer	Mgmt Consultant	IT Professional	Total
Service-Related Charges	$ 1,229,874	$ 3,179,391	$10,807,558	$ 6,003,321	$ 2,336,026	$23,556,170
Overhead Expenses (Note A)	$ 200,556	$ 518,464	$ 1,762,392	$ 978,963	$ 380,936	$ 3,841,312
Cost Pool Total	$ 1,430,430	$ 3,697,855	$12,569,950	$ 6,982,285	$ 2,716,962	$27,397,482
Hours	8,963	36,168	145,581	46,408	23,365	260,485
Average Hourly Rate	**$ 160**	**$ 102**	**$ 86**	**$ 150**	**$ 116**	

Note A: These expenses are assigned to the outside provider categories prorata based on the amount of "direct" expenses in the cost pools, as calculated below.

	Attorney	Certified Public Accnt	Professional Engineer	Mgmt Consultant	IT Professional	Total
Service-Related Charges	$ 1,229,874	$ 3,179,391	$10,807,558	$ 6,003,321	$ 2,336,026	$23,556,170
Percent of Cost Pool Total	5.2%	13.5%	45.9%	25.5%	9.9%	100.0%
Allocation Of Overhead	$ 200,556	$ 518,464	$ 1,762,392	$ 978,963	$ 380,936	$ 3,841,312

Columbia Gas of Virginia, Inc.
Outside Provider Cost Pools for 2020 NCSC Contract Billings Charges

	Outside Provider					
Service Category	Attorney	Certified Public Accountant	Professional Engineer	Management Consultant	IT Professional	Total
Accounts Payable		$ 82,014				$ 82,014
Audit		$ 181,464				$ 181,464
Business Continuity				$ 18,521		$ 18,521
Business Services				$ 1,632,394		$ 1,632,394
Corporate Accounting		$ 615,482				$ 615,482
Corporate Affairs				$ 97,699		$ 97,699
Corporate Communications				$ 106,812		$ 106,812
Corporate Secretary	$ 4,325					$ 4,325
Corporate Security				$ 62,012		$ 62,012
Credit Risk Management				$ 25,734		$ 25,734
Customer Operations		$ 609,204				$ 609,204
Customer Services		$ 200,269				$ 200,269
Engineering Services			$ 2,231,888			$ 2,231,888
Environmental, Health & Safety			$ 982,015			$ 982,015
Executive				$ 2,391,160		$ 2,391,160
Finance		$ 259,104				$ 259,104
Fleet Management			$ 47,946			$ 47,946
Gas Supply			$ 1,396,609			$ 1,396,609
Human Resources				$ 1,195,856		$ 1,195,856
Information Technology					$ 2,336,026	$ 2,336,026
Insurance				$ 94,080		$ 94,080
Investor Relations				$ 66,129		$ 66,129
Legal	$ 1,225,549					$ 1,225,549
Logistics			$ 128,037			$ 128,037
Operations			$ 5,765,265			$ 5,765,265
Regulatory		$ 616,064				$ 616,064
Revenue Transactions		$ 258,345				$ 258,345
Risk Management				$ 77,426		$ 77,426
Safety and Compliance				$ 23,844		$ 23,844
Strategy and Planning				$ 136,704		$ 136,704
Supply Chain			$ 255,797			$ 255,797
Taxes		$ 289,461				$ 289,461
Training				$ 74,948		$ 74,948
Treasury		$ 67,985				$ 67,985
Total	$ 1,229,874	$ 3,179,391	$ 10,807,558	$ 6,003,321	$ 2,336,026	$ 23,556,170

Columbia Gas of Virginia, Inc.
Outside Provider Hour Pools for 2020 NCSC Contract Billings Charges

	Outside Provider					
Service Category	Attorney	Certified Public Accountant	Professional Engineer	Management Consultant	IT Professional	Total
Accounts Payable		1,046				1,046
Audit		1,539				1,539
Business Continuity				210		210
Business Services				25,303		25,303
Corporate Accounting		6,887				6,887
Corporate Affairs				490		490
Corporate Communications				1,254		1,254
Corporate Secretary	-					-
Corporate Security				684		684
Credit Risk Management				216		216
Customer Operations		7,696				7,696
Customer Services		2,393				2,393
Engineering Services			29,607			29,607
Environmental, Health & Safety			8,927			8,927
Executive				2,733		2,733
Finance		2,851				2,851
Fleet Management			588			588
Gas Supply			18,453			18,453
Human Resources				12,214		12,214
Information Technology					23,365	23,365
Insurance				812		812
Investor Relations				438		438
Legal	8,963					8,963
Logistics			1,442			1,442
Operations			83,283			83,283
Regulatory		6,695				6,695
Revenue Transactions		4,151				4,151
Risk Management				479		479
Safety and Compliance				111		111
Strategy and Planning				1,050		1,050
Supply Chain			3,281			3,281
Taxes		2,429				2,429
Training				412		412
Treasury		482				482
Total	8,963	36,168	145,581	46,408	23,365	260,485

Outside Service Provider Hourly Rates

The next step in the lower-of-cost-or-market comparison was to calculate the average billing rates for outside service providers. The source of this information and the determination of the average rates are described in the paragraphs that follow.

It should be noted that professionals working for three of the five outside provider categories may be licensed to practice by state regulatory bodies. However, not every professional working for these firms is licensed. For instance, among Virginia certified public accounting firms, only the more experienced staff members are predominantly licensed CPAs, as shown in the table below. Some NCSC employees also have professional licenses. Thus, it is valid to compare NCSC's hourly rates to those of the outside professional service providers included in this study.

Position	% In VA Who Are CPAs
Partners/Owners	98%
Directors (over 10 years experience)	90%
Managers (6-10 years experience)	72%
Sr Associates (4-5 years experience)	61%
Associates (1-3 years experience)	17%
New Professionals	8%

Source: AICPA's National PCPS/TSCPA Management of an Accounting Practice Survey (2010)

Attorneys

An estimate of Virginia attorney rates was developed from National Law Journal's Survey of Law Firm Economics Report. As shown in Schedule 6 (page 22), data from this survey has been adjusted for cost-of-living differences between each law firm's location and Richmond, Virginia. The hourly rate data from the National Law Review is as of January 1, 2019. The survey's calculated average rate was escalated to June 30, 2020—the midpoint of 2020.

Certified Public Accountants

The average hourly rate for Virginia certified public accountants was developed from a 2018 survey conducted by the American Institute of Certified Public Accountants (AICPA) every two years. Hourly rates in the AICPA survey are the average of firms in Virginia. The average hourly rate was calculated for a range of accountant positions, as shown in Schedule 7 (page 23). Based on a typical staff assignment by each accountant position, a weighted average hourly rate was calculated. This survey covered hourly rates in effect during 2017. The calculated average rate was escalated to June 30, 2020—the midpoint of 2020.

Professional Engineers

NCSC provided 2020 hourly rate information for several firms that perform services that could be used by CVA when outside engineering services are required. As shown in Schedule 8 (page 24), an average rate was developed for a range of engineering positions. Then, using a typical percentage mix by position for a typical engineering project, a weighted average cost per hour was calculated.

Management Consultants

The cost per hour for management consultants was developed from a survey performed by Rodenhauser & Company, LLC, a research company that monitors the consulting industry. The survey includes rates that were in effect during 2020 for firms throughout the United States. Consultants typically do not limit their practice to any one region and must travel to a client's location. Thus, the U.S. national average is appropriate for comparison.

The first step in the calculation, presented in Schedule 9 (page 25), was to determine an average rate by consultant position level. From these rates, a single weighted average hourly rate was calculated based upon the percent of time that is typically applied to a consulting assignment by each consultant position level. This survey covered hourly rates in effect during 2020.

Information Technology Professionals

The 2020 average hourly rate for information technology consultants and contractors was developed from two sources: NCSC for IT contractor rates and a survey performed by Rodenhauser & Company, LLC, for IT consultants. As shown in Schedule 10 (page 26), that data was compiled and a weighted average was calculated based on a percent of time that is typically applied to an IT consulting assignment, based on Baryenbruch & Company's experience.

Columbia Gas of Virginia, Inc.
Estimated 2020 Billing Rates for Virginia Attorneys

Average Hourly Billing Rates as of January 1, 2019

	2019 Avg Billing Rates (Note A)		Weighted Avg Rate Calculation			Cost of Living (COL) Adjustment			
			0.25	0.75	(X)	COL Indices (Note B)		(Y)	(X x Y)
Region	Partner	Associate	Partner	Associate	Weighted Average	Region	Richmond, VA	COL Adjustment	Adjusted Rate
New England	$ 432	$ 259	$ 108	$ 194	$ 302	123.5	99.7	80.7%	$ 244
Mid-Atlantic	$ 575	$ 424	$ 144	$ 318	$ 462	119.9	99.7	83.1%	$ 384
South Atlantic	$ 510	$ 311	$ 128	$ 233	$ 361	97.6	99.7	102.1%	$ 368
West South Central	$ 448	$ 301	$ 112	$ 226	$ 338	91.8	99.7	108.6%	$ 367
East North Central	$ 493	$ 354	$ 123	$ 266	$ 389	93.5	99.7	106.7%	$ 415
West North Central	$ 294	$ 207	$ 74	$ 155	$ 229	94.7	99.7	105.3%	$ 241
Mountain	$ 500	$ 310	$ 125	$ 233	$ 358	97.5	99.7	102.3%	$ 366
Pacific	$ 345	$ 257	$ 86	$ 193	$ 279	118.9	99.7	83.9%	$ 234
Overall Average Hourly Billing Rate									$ 327
Escalation to Test Period 2020 Midpoint (June 30, 2020)									
CPI at December 31, 2018									251.2
CPI at June 30, 2020									257.8
Inflation/Escalation (Note C)									2.6%
Average Hourly Billing Rate For Attorneys At June 30, 2020									$ 336

Note A: 2019 Survey of Law Firm Economics Report, National Law Journal
Note B: Cost of Living Index, Source Council for Community and Economic Research
Note C: U.S. Bureau of Labor Statistics (http://data.bls.gov/cgi-bin/surveymost)

Schedule 7

Columbia Gas of Virginia, Inc.
2020 Billing Rates for Virginia Certified Public Accountants

A. Calculation of Average Hourly Billing Rate by Public Accounting Position
Survey billing rates were those in effect in 2017 (Note A)

	Average Hourly Billing Rate (Note A)				
	Staff Accountant	Senior Accountant	Manager	Partner	
Average Hourly Billing Rate by CPA Firm Position	$ 124	$ 121	$ 174	$ 249	
Percent of Accounting Assignment	30%	30%	20%	20%	Weighted Average
	$ 37	$ 36	$ 35	$ 50	$ 158

Escalation to Test Period Midpoint (June 30, 2020)	
CPI at December 31, 2017	246.5
CPI at June 30, 2020	257.8
Inflation/Escalation (Note B)	4.6%
Average Hourly Billing Rate For Virginia CPAs At June 30, 2020	$ 165

Note A: Source is AICPA's 2018 National PCPS/TSCPA Management of an Accounting Practice Survey (Virginia edition)
Note B: Source is U.S. Bureau of Labor Statistics (https://data.bls.gov/cgi-bin/surveymost)

Schedule 8

Columbia Gas of Virginia, Inc.
2020 Billing Rates for Virginia Engineers

Note: Billing rates were those in effect in 2020

A. Calculation of Average Hourly Rate by Engineer Position

	Average Hourly Billing Rates			
Firm	Engineer Tech, Land Agent, CAD Technician	Engineer Land Surveyor, Envir. Scientist	Senior Engineer, Project Manager	Principal Engineer
Firm #1	$84	$118	$177	$212
Firm #2	$95	$194	$274	$376
Firm #3	$63	$78	na	na
Firm #4	$74	$95	na	na
Firm #5	$59	$74	na	na
Firm #6	$70	na	na	na
Firm #7	$79	$90	$123	na
Firm #8	$59	$84	$92	na
Firm #9	$59	$81	na	na

B. Calculation of Overall Average Engineering Hourly Billing Rate

	Engineer Tech, Land Agent, CAD Technician	Engineer Land Surveyor, Envir. Scientist	Senior Engineer, Project Manager	Principal Engineer	
Average Hourly Billing Rate (From Above)	$71	$102	$167	$294	
Typical Percent of Time on an Engineering Assignment	33%	33%	24%	10%	Weighted Average
	$24	$34	$40	$29	$127

Source: Information provided by NCSC. Firm names are confidential.

Schedule 9

Columbia Gas of Virginia, Inc.
2020 Billing Rates for U.S. Management Consultants

Survey billing rates in effect in 2020 (Note A)

A. Calculation of Average Hourly Billing Rate by Consultant Position

	Average Hourly Rates (Note A)				
	Analyst Consultant	Associate	Sr. Assoc/ Manager	Principal	Partner
Average	$ 227	$ 273	$ 334	$ 515	$ 641

B. Calculation of Overall Average Hourly Billing Rate Based on a Typical Distribution of Time on an Engagement

	Entry-Level Consultant	Associate Consultant	Senior Consultant	Junior Partner	Senior Partner	Weighted Average
Average Hourly Billing Rate (from above)	$ 227	$ 273	$ 334	$ 515	$ 641	
Percent of Consulting Assignment	30%	30%	25%	10%	5%	
	$ 68	$ 82	$ 84	$ 52	$ 32	$ 317

Average Hourly Billing Rate For Management Consultants During 2020 $ 317

Note A: Source is Rodenhauser & Company, LLC

Schedule 10

Columbia Gas of Virginia, Inc.
2020 Billing Rates for Information Technology Professionals

A. Calculation of Average Hourly Billing Rate by Information Technology Position
Survey billing rates were those in effect in 2020 (Note A)

	Average Hourly Billing Rate (Note A)					
	Contractor Positions		Consultant Positions			
	Contractor	Senior Contractor	Associate	Manager	Partner	
Average Hourly Billing Rate by IT Position Category	$ 70	$ 105	$ 252	$ 353	$ 478	
Percent of IT Assignment	25%	25%	25%	15%	10%	Weighted Average
	$ 18	$ 26	$ 63	$ 53	$ 48	$ 207

Note A: Source is NCSC, Rodenhauser & Company, LLC, and Baryenbruch & Company, LLC

NCSC Versus Outside Provider Cost Comparison

As shown in the table below, NCSC's costs per hour are considerably lower than those of outside providers.

	2020 Cost/Hour Difference		
Service Provider	NCSC	Outside Providers	Difference--NCSC Greater(Less) Than Outside
Attorney	$ 160	$ 305	$ (145)
Certified Public Accountant	$ 102	$ 165	$ (63)
Professional Engineer	$ 86	$ 127	$ (41)
Management Consultant	$ 150	$ 317	$ (167)
IT Professional	$ 116	$ 207	$ (91)

As calculated below, based on these cost-per-hour differentials and the number of hours that NCSC billed CVA during 2020, the services would cost nearly $20.7 million more from outside providers. This is 71% more ($19,423,384/ $27,211,913 = 71%) than NCSC's total 2020 testable contract services billings to CVA.

	2020 Total Cost Difference		
Service Provider	Hourly Rate Difference--NCSC Greater(Less) Than Outside	NCSC Hours Charged	Dollar Difference
Attorney	$ (145)	8,963	$ (1,299,631)
Certified Public Accountant	$ (63)	36,168	$ (2,278,576)
Professional Engineer	$ (41)	145,581	$ (5,968,807)
Management Consultant	$ (167)	46,408	$ (7,750,115)
IT Professional	$ (91)	23,365	$ (2,126,254)
		Total NCSC Less Than Outside Providers	$ (19,423,384)

Methodology

Customer Accounts Services covers the following utility functions:

- Customer Call Center – customer calls/contact, credit, order taking/disposition, bill collection efforts, outage calls
- Call Center IT – maintenance of phone banks, voice recognition units, call center software applications, telecommunications
- Customer billing – bill printing, stuffing, and mailing
- Remittance processing – processing customer payments received in the mail
- Bill payment centers – locations where customers can pay their bills in person

Certain of these functions are performed for CVA by NCSC. Others are performed by CVA itself. For this reason, total expenses for customer accounts services are subjected to comparison.

It is difficult to compare the cost of NCSC and other affiliate customer accounts services charges to CVA with those of outside providers of the same services because survey data is proprietary and expensive to obtain. For this reason, CVA's charges from affiliates for customer accounts services are compared to those of neighboring utilities because the data necessary to make such comparison is available to the public.

Cost information regarding comparison group utilities comes from the FERC Form 1 that each utility must file. FERC's chart of accounts is defined in Chapter 18, Part 101, of the Code of Federal Regulations. FERC accounts that contain customer accounts services expenses are Account 903 Customer Accounts Expense – Records and Collection Expense and Account 905 Customer Accounts Expense – Miscellaneous Customer Accounts Expense. Schedule 11 provides FERC's definition of the type of expenses that should be recorded in these accounts.

In addition to the charges in these FERC accounts, labor-related overhead charged to the following FERC accounts must be added to the labor components of Accounts 903 and 905:

- Account 926 Employee Pension and Benefits
- Account 408 Taxes Other Than Income (employer's portion of FICA)

903 – Customer Records and Collection Expenses

This account shall include the cost of labor, materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.

Labor

1. Receiving, preparing, recording and handling routine orders for service, disconnections, transfers or meter tests initiated by the customer, excluding the cost of carrying out such orders, which is chargeable to the account appropriate for the work called for by such orders.
2. Investigations of customers' credit and keeping of records pertaining thereto, including records of uncollectible accounts written off.
3. Receiving, refunding or applying customer deposits and maintaining customer deposit, line extension, and other miscellaneous records.
4. Checking consumption shown by meter readers' reports where incidental to preparation of billing data.
5. Preparing address plates and addressing bills and delinquent notices.
6. Preparing billing data.
7. Operating billing and bookkeeping machines.
8. Verifying billing records with contracts or rate schedules.
9. Preparing bills for delivery, and mailing or delivering bills.
10. Collecting revenues, including collection from prepayment meters unless incidental to meter reading operations.
11. Balancing collections, preparing collections for deposit, and preparing cash reports.
12. Posting collections and other credits or charges to customer accounts and extending unpaid balances.
13. Balancing customer accounts and controls.
14. Preparing, mailing, or delivering delinquent notices and preparing reports of delinquent accounts.
15. Final meter reading of delinquent accounts when done by collectors incidental to regular activities.
16. Disconnecting and reconnecting services because of nonpayment of bills.
17. Receiving, recording, and handling of inquiries, complaints, and requests for investigations from customers, including preparation of necessary orders, but excluding the cost of carrying out such orders, which is chargeable to the account appropriate for the work called for by such orders.
18. Statistical and tabulating work on customer accounts and revenues, but not including special analyses for sales department, rate department, or other general purposes, unless incidental to regular customer accounting routines.
19. Preparing and periodically rewriting meter reading sheets.
20. Determining consumption and computing estimated or average consumption when performed by employees other than those engaged in reading meters.

Materials and expenses

21. Address plates and supplies.
22. Cash overages and shortages.
23. Commissions or fees to others for collecting.
24. Payments to credit organizations for investigations and reports.
25. Postage.
26. Transportation expenses, including transportation of customer bills and meter books under centralized billing procedure.
27. Transportation, meals, and incidental expenses.
28. Bank charges, exchange, and other fees for cashing and depositing customers' checks.
29. Forms for recording orders for services, removals, etc.
30. Rent of mechanical equipment.

905 – Miscellaneous Customer Accounts Expenses

This account shall include the cost of labor, materials used and expenses incurred not provided for in other accounts.

Labor

1. General clerical and stenographic work.
2. Miscellaneous labor.

Materials and expenses

3. Communication service.
4. Miscellaneous office supplies and expenses and stationery and printing other than those specifically provided for in accounts 902 and 903.

Comparison Group

Neighboring utilities included in the comparison group are shown in the table below. These are companies whose FERC Form 1 shows amounts for Accounts 903 and 905.

State	Utilities Providing FERC Form 1 Information	
Virginia	• Appalachian Power	• Virginia Electric & Power
Kentucky	• Duke Energy Kentucky • Kentucky Power	• Kentucky Utilities • Louisville Gas & Electric
West Virginia	• Appalachian Power • Monongahela Power	• Potomac Edison • Wheeling Power
North Carolina	• Duke Energy Carolinas	• Progress Energy Carolinas
Maryland	• Baltimore Gas & Electric • Delmarva Power & Light	• Potomac Edison • Potomac Electric
Tennessee	• Kingsport Power	

CVA Cost per Customer

As calculated in Schedule 12 (page 32), CVA's 2020 customer accounts expense per customer is $18.53. CVA's cost pool includes the same expense items that are included in the neighboring utilities' customer accounts expenses.

Comparison Group Cost per Customer

Schedule 13 (pages 33-35) shows the calculation of actual 2019 customer accounts expense per customer for the utility comparison group. The underlying data were taken from each utility's FERC Form 1.

Summary of Results

As shown in the table below, CVA's cost per customer is well below the utility comparison group average. CVA's average of $18.53 is lower than 13 of the 15 comparison group utilities. Based upon this data, 2020 charges from NCSC and other affiliates for customer account services are reasonable.

Customer Account Expenses Per Customer	
Potomac Electric Power Company	$ 88.17
Delmarva Power & Light Company	$ 85.56
Kentucky Utilities Company	$ 41.99
Baltimore Gas and Electric Company	$ 34.89
Kentucky Power Company	$ 33.81
Comparison Group Average	**$ 32.93**
Duke Energy Kentucky, Inc.	$ 29.84
Appalachian Power Company	$ 29.08
Duke Energy Progress, LLC	$ 26.83
Duke Energy Carolinas, LLC	$ 26.48
Kingsport Power Company	$ 25.76
Wheeling Power Company	$ 25.62
Virginia Electric And Power Company	$ 21.06
Louisville Gas and Electric Company	$ 19.01
Columbia Gas of Virginia	**$ 18.53**
Monongahela Power Company	$ 15.70
Potomac Edison Company	$ 10.44

Schedule 12

Columbia Gas of Virginia, Inc.
CVA 2020 Customer Accounts Expense Per Customer

NiSource Company	Source of Charges		Amount
Service Company (12)	0019000 Customer Org Exec	$	21,159
(Contract Services)	0021200 Customer Insights_Performance	$	60,911
	0030300 Customer Contact Center	$	66,140
	0030310 Smithfield Customer Care Centr	$	1,289,979
	0053000 Meter to Cash Administration	$	61,781
	0053600 Mailing Operations	$	323,738
	0056100 Cash Operations	$	471,733
	0056200 DIS Billing Exceptions	$	192,691
	0056300 Revenue Recovery	$	244,151
	0057500 Integr Center - Ldrs-Admin	$	28,069
	Other	$	17,648
Service Company (12)	Postage (Convenience Billed)	$	946,492
CG-Ohio (34)	0334300 - Undistributed	$	44
CG-Virginia	0088800 Fleet Allocation	$	35,371
	0318230 GM Field Operations	$	15,375
	0336100 Operations-Admin	$	8,376
	0337300 Op Center - Admin-Fredercksbrg	$	27,957
	0337600 Op Center - Admin-Lynchburg	$	7,713
	0337700 Op Center - Admin-Chester	$	54,183
	0338100 Op Center - Admin-Staunton	$	9,540
	0338150 Op Center - Admin-Gainsville	$	26,100
	0338300 Op Center - Admin-Lexington	$	7,485
	0339100 Op Center - Admin-Portsmouth	$	51,906
	0363290 Printing and Inserting	$	946,492
	Other	$	1,123
	Customer Payment Processing Expense (A)	$	251,032
	Customer Accounts Cost Pool Total	$	5,167,188
	CVA customers at 12/31/20		278,924
	2020 Cost Per Customer	$	18.53

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Columbia Gas of Virginia, Inc.
Comparison Group 2020 Customer Accounts Expense Per Customer

	Virginia		Kentucky			
	Appalachian Power	Virginia Electric & Power	Duke Energy Kentucky	Kentucky Power	Kentucky Utilities	Louisville Gas & Electric
Customer Account Services Cost Pool						
FERC Account Balances:						
Account 903 - Customer Records & Collection (page 322, line 161)	$ 26,777,725	$ 47,935,932	$ 3,929,528	$ 5,429,725	$ 20,644,218	$ 7,096,363
Account 905 - Misc Customer Accounts (page 322, line 163)	$ 186,037	$ -	$ 1,039	$ 28,897	$ (21,536)	$ 7,877
Subtotal	$ 26,963,762	$ 47,935,932	$ 3,930,567	$ 5,458,622	$ 20,622,682	$ 7,104,240
Add: Employee Benefits & Employer FICA (not included in above amounts)						
Account 926 - Employee Pension & Benefits (Note A)	$ 235,152	$ 5,157,160	$ 185,329	$ 40,895	$ 1,934,383	$ 547,377
Account 408 - Taxes Other Than Income (Employer's Portion of FICA) (Note B	$ 561,102	$ 2,255,258	$ 163,494	$ 95,372	$ 795,495	$ 251,819
Total Cost Pool	$ 27,760,016	$ 55,348,349	$ 4,279,390	$ 5,594,889	$ 23,352,559	$ 7,903,437
Total Customers (page 304, line 43)	954,688	2,627,789	143,431	165,461	556,129	415,853
Customer Account Services Expense per Customer	**$ 29.08**	**$ 21.06**	**$ 29.84**	**$ 33.81**	**$ 41.99**	**$ 19.01**
Note A: Pension & Benefits Pertaining to Customer Acct Services						
Account 926 - Employee Pension & Benefits (page 323, line 187)	$ 6,211,060	$ 175,914,272	$ 5,465,650	$ 1,535,399	$ 27,133,749	$ 20,086,498
Total O&M Payroll (page 355, line 65)	$ 193,730,397	$1,005,599,841	$ 63,028,868	$ 46,807,487	$ 145,862,368	$ 120,793,999
Benefits as Percent of Payroll	3.2%	17.5%	8.7%	3.3%	18.6%	16.6%
Payroll Applicable to Customer Account Services						
Total Payroll Charged to Customer Accounts Function						
Electric (page 354, line 7)	$ 8,599,596	$ 35,704,557	$ 2,427,717	$ 1,356,910	$ 13,158,577	$ 4,512,294
Percent Applicable to Customer Accounts Services (903 and 905):						
Account 903 - Customer Records & Collection (page 322, line 161)	$ 26,777,725	$ 47,935,932	$ 3,929,528	$ 5,429,725	$ 20,644,218	$ 7,096,363
Account 905 - Misc Customer Accounts (page 322, line 163)	$ 186,037	$ -	$ 1,039	$ 28,897	$ (21,536)	$ 7,877
Subtotal - Total Charges Applicable to Customer Accounts Services	$ 26,963,762	$ 47,935,932	$ 3,930,567	$ 5,458,622	$ 20,622,682	$ 7,104,240
Account 902 - Meter Reading Expenses (page 322, line 160)	$ 4,650,117	$ 10,120,469	$ 534,343	$ 482,553	$ 5,473,575	$ 2,634,152
Total Charges Applicable to Customer Acccounts Svcs & Meter Reading	$ 31,613,879	$ 58,056,401	$ 4,464,910	$ 5,941,175	$ 26,096,257	$ 9,738,392
Percent Applicable to Customer Accounts Services (903 and 905)	85.3%	82.6%	88.0%	91.9%	79.0%	73.0%
Customer Account Services Portion of Total Payroll	$ 7,334,673	$ 29,480,491	$ 2,137,177	$ 1,246,699	$ 10,398,623	$ 3,291,757
Pension & Benefits Pertaining to Customer Accounts Services	$ 235,152	$ 5,157,160	$ 185,329	$ 40,895	$ 1,934,383	$ 547,377
Note B: Calculation of Employer's FICA Pertaining to Customer Accounts Services						
Customer Account Services Portion of Total Payroll	$ 7,334,673	$ 29,480,491	$ 2,137,177	$ 1,246,699	$ 10,398,623	$ 3,291,757
Employer's Portion of FICA (6.20%) and Medicare (1.45%)	7.65%	7.65%	7.65%	7.65%	7.65%	7.65%
Estimated Employer's Portion of FICA	$ 561,102	$ 2,255,258	$ 163,494	$ 95,372	$ 795,495	$ 251,819

Columbia Gas of Virginia, Inc.
Comparison Group 2020 Customer Accounts Expense Per Customer

	West Virginia				North Carolina	
	Appalachian Power	Monongahela Power	Potomac Edison	Wheeling Power	Duke Energy Carolinas	Duke Energy Progress
Customer Account Services Cost Pool						
FERC Account Balances:						
Account 903 - Customer Records & Collection (page 322, line 161)		$ 5,328,712	$ 4,650,411	$ 1,010,790	$ 65,530,595	$ 38,795,775
Account 905 - Misc Customer Accounts (page 322, line 163)		$ 401,685	$ 414,763	$ 7,121	$ 255,858	$ 594,168
Subtotal		$ 5,730,397	$ 5,065,174	$ 1,017,911	$ 65,786,453	$ 39,389,943
Add: Employee Benefits & Employer FICA (not included in above amounts)						
Account 926 - Employee Pension & Benefits (Note A)		$ 179,972	$ (899,768)	$ 22,546	$ 2,097,555	$ 1,881,476
Account 408 - Taxes Other Than Income (Employer's Portion of FICA) (Note B)		$ 243,171	$ 182,316	$ 24,300	$ 2,313,547	$ 1,410,439
Total Cost Pool		$ 6,153,540	$ 4,347,722	$ 1,064,758	$ 70,197,555	$ 42,681,858
Total Customers (page 304, line 43)		391,968	416,587	41,559	2,650,817	1,590,969
Customer Account Services Expense per Customer	**see VA**	**$ 15.70**	**$ 10.44**	**$ 25.62**	**$ 26.48**	**$ 26.83**
Note A: Pension & Benefits Pertaining to Customer Acct Services						
Account 926 - Employee Pension & Benefits (page 323, line 187)		$ 5,546,136	$ (15,759,243)	$ 1,199,690	$ 88,007,473	$ 87,774,392
Total O&M Payroll (page 355, line 65)		$ 97,956,969	$ 41,741,554	$ 16,902,180	$ 1,268,887,430	$ 860,126,180
Benefits as Percent of Payroll		5.7%	-37.8%	7.1%	6.9%	10.2%
Payroll Applicable to Customer Account Services						
Total Payroll Charged to Customer Accounts Function						
Electric (page 354, line 7)		$ 7,702,651	$ 4,490,032	$ 398,035	$ 31,371,061	$ 21,023,608
Percent Applicable to Customer Accounts Services (903 and 905):						
Account 903 - Customer Records & Collection (page 322, line 161)		$ 5,328,712	$ 4,650,411	$ 1,010,790	$ 65,530,595	$ 38,795,775
Account 905 - Misc Customer Accounts (page 322, line 163)		$ 401,685	$ 414,763	$ 7,121	$ 255,858	$ 594,168
Subtotal - Total Charges Applicable to Customer Accounts Services		$ 5,730,397	$ 5,065,174	$ 1,017,911	$ 65,786,453	$ 39,389,943
Account 902 - Meter Reading Expenses (page 322, line 160)		$ 8,155,533	$ 4,477,719	$ 257,592	$ 2,455,088	$ 5,525,904
Total Charges Applicable to Customer Acccounts Svcs & Meter Reading		$ 13,885,930	$ 9,542,893	$ 1,275,503	$ 68,241,541	$ 44,915,847
Percent Applicable to Customer Accounts Services (903 and 905)		41.3%	53.1%	79.8%	96.4%	87.7%
Customer Account Services Portion of Total Payroll		$ 3,178,703	$ 2,383,218	$ 317,651	$ 30,242,442	$ 18,437,117
Pension & Benefits Pertaining to Customer Accounts Services		$ 179,972	$ (899,768)	$ 22,546	$ 2,097,555	$ 1,881,476
Note B: Calculation of Employer's FICA Pertaining to Customer Accounts Services						
Customer Account Services Portion of Total Payroll		$ 3,178,703	$ 2,383,218	$ 317,651	$ 30,242,442	$ 18,437,117
Employer's Portion of FICA (6.20%) and Medicare (1.45%)		7.65%	7.65%	7.65%	7.65%	7.65%
Estimated Employer's Portion of FICA		$ 243,171	$ 182,316	$ 24,300	$ 2,313,547	$ 1,410,439

Columbia Gas of Virginia, Inc.
Comparison Group 2020 Customer Accounts Expense Per Customer

	Maryland				Tennessee	
	Baltimore Gas & Electric	Delmarva Power & Light	Potomac Edison	Potomac Electric	Kingsport Power	
Customer Account Services Cost Pool						
FERC Account Balances:						
Account 903 - Customer Records & Collection (page 322, line 161)	$ 39,939,906	$ 44,688,121		$ 75,039,785	$ 1,217,477	
Account 905 - Misc Customer Accounts (page 322, line 163)	$ 704,113	$ -		$ -	$ 7,123	
Subtotal	$ 40,644,019	$ 44,688,121		$ 75,039,785	$ 1,224,600	
Add: Employee Benefits & Employer FICA (not included in above amounts)						
Account 926 - Employee Pension & Benefits (Note A)	$ 2,872,245	$ 375,682		$ 2,385,257	$ (3,852)	**Group**
Account 408 - Taxes Other Than Income (Employer's Portion of FICA) (Note B	$ 1,823,711	$ 223,290		$ 988,963	$ 23,357	**Average**
Total Cost Pool	$ 45,339,975	$ 45,287,093		$ 78,414,005	$ 1,244,105	$ 418,969,251
Total Customers (page 304, line 43)	1,299,421	529,284		889,380	48,290	12,721,626
Customer Account Services Expense per Customer	**$ 34.89**	**$ 85.56**	**see WV**	**$ 88.17**	**$ 25.76**	**$ 32.93**
Note A: Pension & Benefits Pertaining to Customer Acct Services						
Account 926 - Employee Pension & Benefits (page 323, line 187)	$ 45,372,605	$ 11,305,901		$ 23,226,905	$ (67,299)	
Total O&M Payroll (page 355, line 65)	$ 376,588,287	$ 87,840,004		$ 125,885,262	$ 5,334,042	
Benefits as Percent of Payroll	12.0%	12.9%		18.5%	-1.3%	
Payroll Applicable to Customer Account Services						
Total Payroll Charged to Customer Accounts Function						
Electric (page 354, line 7)	$ 24,805,993	$ 3,008,983		$ 13,098,171	$ 340,195	
Percent Applicable to Customer Accounts Services (903 and 905):						
Account 903 - Customer Records & Collection (page 322, line 161)	$ 39,939,906	$ 44,688,121		$ 75,039,785	$ 1,217,477	
Account 905 - Misc Customer Accounts (page 322, line 163)	$ 704,113	$ -		$ -	$ 7,123	
Subtotal - Total Charges Applicable to Customer Accounts Services	$ 40,644,019	$ 44,688,121		$ 75,039,785	$ 1,224,600	
Account 902 - Meter Reading Expenses (page 322, line 160)	$ 1,648,027	$ 1,380,382		$ 989,971	$ 139,880	
Total Charges Applicable to Customer Acccounts Svcs & Meter Reading	$ 42,292,046	$ 46,068,503		$ 76,029,756	$ 1,364,480	
Percent Applicable to Customer Accounts Services (903 and 905)	96.1%	97.0%		98.7%	89.7%	
Customer Account Services Portion of Total Payroll	$ 23,839,359	$ 2,918,823		$ 12,927,622	$ 305,320	
Pension & Benefits Pertaining to Customer Accounts Services	$ 2,872,245	$ 375,682		$ 2,385,257	$ (3,852)	
Note B: Calculation of Employer's FICA Pertaining to Customer Accounts Services						
Customer Account Services Portion of Total Payroll	$ 23,839,359	$ 2,918,823		$ 12,927,622	$ 305,320	
Employer's Portion of FICA (6.20%) and Medicare (1.45%)	7.65%	7.65%		7.65%	7.65%	
Estimated Employer's Portion of FICA	$ 1,823,711	$ 223,290		$ 988,963	$ 23,357	

COLUMBIA STATEMENT NO. 16-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
v.	)	DOCKET NO. R-2021-3024296
	)	
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REJOINDER TESTIMONY OF
PATRICK L. BARYENBRUCH
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2021

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DOCKET NO. R-2021-3024296
COLUMBIA GAS OF PENNSYLVANIA
REJOINDER TESTIMONY OF PATRICK BARYENBRUCH
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REJOINDER TESTIMONY

PATRICK L. BARYENBRUCH

I. INTRODUCTION

Q. Please state your name, position of employment and business address.

A. My name is Patrick L. Baryenbruch. I am the President of my own consulting practice, Baryenbruch & Company, LLC, which was established in 1985. In that capacity, I provide consulting services to utilities and their regulators. My business address is 2832 Claremont Road, Raleigh, North Carolina 27608.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted Rebuttal Testimony on July 14, 2021, marked as Columbia Statement No. 16-R.

Q. What is the purpose of this Rejoinder Testimony?

A. I am responding to the Surrebuttal Testimony of Mr. David Effron, witness for the Pennsylvania Office of Consumer Advocate.

Q. What part of his Surrebuttal Testimony will you address?

A. I will cover his comments in the NCSC Expense section starting on line 17 of page 16 through line 2 of page 23.

Q. Please summarize the points on which you disagree with Mr. Effron's Surrebuttal Testimony?

A. I will cover several points: (1) the amount of the increase in NCSC charges to Columbia, (2) my cost comparison for service company administrative and general (A&G) charges, and (3) my cost comparison for total A&G expenses.

II. INCREASE IN NCSC CHARGES TO COLUMBIA

Q. Why does Mr. Effron state you understate the increase in NCSC charges to Columbia?

A. On page 3 of my Rebuttal Testimony, I present the following set of numbers as an introduction to my cost comparisons that follow in my testimony.

Analysis of NCSC O&M-Related Charges to Columbia

	Amount	
HTY	$ 62,365,898	< used for cost comparison
FTY	$ 73,507,000	
FPFTY	$ 76,860,000	

My Rebuttal Testimony (OCA Statement No. 1-SR, pages 16-17) cites the increase in NCSC O&M-related charges of approximately $14.5 million from the HTY to the FPFTY. Mr. Effron states the increase should be approximately $18.0 million, which is the difference between the normalized HTY ($58,867,000) and the FPFTY. Both increases are correct.

Q. Is the difference in the increases in NCSC charges relevant to the cost comparisons you make in your Rebuttal Testimony?

A. No. The basis for my cost comparisons is actual HTY NCSC charges, which is a higher amount than the normalized HTY charges. I calculate Columbia's NCSC charges per customer based on actual HTY NCSC charges. The comparison metric I use is administrative and general (A&G) expenses per customer. The time periods for which I make cost comparisons are HTY and 2021 proforma. The table below analyzes NCSC charges and designates the amounts I used in my cost comparisons. It should be noted that my Proforma 2021 charges of $73,765,898 are higher than Columbia's FTY charges of $73,507,000.

	Operations & Maintenance Charges	Administrative & General Charges (A)	Total Charges
HTY	$ 5,225,937	$ 57,139,961	$ 62,365,898
Divestiture-Related Increase	$ 955,260	$ 10,444,740	$ 11,400,000
Proforma NCSC 2021 Charges	$ 6,181,197	$ 67,584,701	$ 73,765,898
		used for cost comparison	

Note A: These are charges to the 900 series of FERC accounts

As this shows, the difference in increases in NCSC charges that Mr. Effron attempts to inflate in importance has absolutely no relevance to my cost comparisons.

III. COST COMPARISON – SERVICE COMPANY A&G CHARGES

Q. What is Mr. Effron's position with respect to your cost comparisons?

A. Essentially, Mr. Effron recommends that my cost comparisons not be considered in determining the reasonableness of NCSC's charges to Columbia.

Q. What cost comparisons do you make?

A. I perform two cost comparisons: (1) service company A&G charges per customer and (2) total A&G expenses (both incurred by the utility and allocated from a service company affiliate) per customer. I compare A&G costs because substantially all service companies that are part of a utility holding company structure deliver A&G services to their utility affiliates.

Q. What utility groups do you use for your comparisons?

A. For the service company A&G charges per customer comparison I use a group of 21 utility holding companies with service company affiliates providing services to utility operating companies. For the total A&G expenses comparison, I use a group of 28 utilities in Pennsylvania and neighboring states.

Q. What is Mr. Effron's issue with your first cost comparison—service company A&G charges per customer?

A. He contends that I do not "weigh or analyze the extent to which the utilities in the comparison group rely on the service company for A&G services (as opposed to incurring the A&G expense in house) as compared to the extent to which Columbia relies on NCSC for A&G services" (OCA Statement No. 1-SR, pages 18-19).

Q. What is your response?

A. Mr. Effron seems to believe there is a way to determine the specific types of services each service company provides to its affiliated operating utilities. He imagines this information can then be converted to a set of adjustments for each comparison group company's per-customer charges. This is completely impractical for purposes of a rate case proceeding. What Mr. Effron envisions would involve a detailed benchmarking study where participant utilities exchange information on the nature of all service company services and the processes by which these services are delivered. This would be a significant undertaking for the 21 utility holding companies in the comparison group. I have never seen anything like this required as supporting evidence in a rate case proceeding.

Q. Are there differences in the extent to which A&G services have been centralized?

A. Yes, there are some differences among utility holding companies in the extent to which A&G functions are centralized into a service company. Certain A&G functions, such as executive management, information technology, finance, accounting, financial planning and analysis, auditing, taxes, human resources, legal and regulatory affairs have a consistent degree of centralization. For other A&G functions, such as customer service, the extent of centralization can vary from one holding company to another. The differences are addressed by having a sufficient number of companies in the comparison group so that structural differences are offset in the average cost per customer. I believe I have achieved that balance in the cost comparisons in my Surrebuttal Testimony.

I am able to make these observations based on my 45 years of experience serving the utility industry in public accounting and management consulting. During that time, I have provided services to utilities or service companies within 13 of the 21 utility holding companies in the comparison group.

Q. Does Mr. Effron object to any other aspect of your service company A&G charge cost comparison?

A. Yes. He does not believe my cost comparison is appropriate for Columbia's NCSC A&G charges including those related to the CMA divestiture. He believes I understate Columbia's cost per customer. (OCA Statement No. 1-SR, pages 19-20).

Q. How do you respond?

A. Mr. Effron is incorrect. The purpose of this comparison is to show the impact of the additional $11.4 million in NCSC costs associated with the divestiture of CMA. I add the A&G portion of that increase to Columbia's actual HTY A&G charges from NCSC to develop a proforma 2021 cost per customer. I should point out that the total of my A&G cost pool is $67,584,701, as shown in the table above, which is higher than Columbia's FTY NCSC A&G charges of $67,211,243. So, my proforma 2021 A&G cost pool is in line with the FTY projection.

Mr. Effron argues that my proforma 2021 cost pool should include an additional escalation for the year 2021. However, that escalation is, in effect, already in my 2021 A&G cost pool so his proposal double counts the 2021 escalation.

Q. Does Mr. Effron object to any other aspect of your service company A&G charge cost comparison?

A. Yes. He criticizes my cost comparison because it is not extended out to the FPFTY. (OCA Statement No. 1-SR, page 20).

Q. How do you respond?

A. The scope of my testimony is the impact of the additional $11.4 million in NCSC charges to Columbia that are associated with the divestiture of CMA. I accomplished the associated cost comparison by assuming the entirely of that increase occurred in 2021. I did not extend the cost comparison into 2022 because it is difficult to forecast changes in the comparison group's service company A&G charge per customer. For my comparison, I used 2.44% as the 2020 to 2021 escalator. However, that is significantly less that the comparison group's cost-per-customer increase from 2019 to 2020, which was 11% as calculated below. It is entirely possible that the comparison group's average will escalate by far more in 2021 and 2022. Two years of 11% escalation on top of the 2020 comparison group average of $127 would bring the 2022 cost per customer to around $156. Because of the uncertainty of future comparison group costs, I did not extend my comparison into 2022.

Year	A&G Charges/ Customer
2019	$ 114
2020	$ 127
% Increase	11%

Q. Do you still believe your service company A&G charges comparison demonstrate that NCSC's charges to Columbia are reasonable?

A. Yes. Furthermore, nothing Mr. Effron presented in his Direct and Surrebuttal Testimonies demonstrates NCSC's charges to Columbia are unreasonable.

Q. Have you used this cost comparisons in previous studies for rate case proceedings?

A. Yes. The service company A&G charges comparison is part of every one of my rate case testimonies. Regulators view these cost comparisons as a useful way to put into perspective the absolute amounts charged by a service company affiliate to a regulated utility.

IV. COST COMPARISON – TOTAL A&G EXPENSES

Q. What is Mr. Effron's concern with your comparison of total A&G expenses?

A. He is concerned with the FERC accounts whose balances I use in my total A&G expense comparison that is presented in my Rebuttal Testimony. Let me briefly summarize how this comparison is constructed. For the comparison group, I obtain expense data from the 2020 FERC Form 1, pages 320-323. I include the total balances in the 900 series of FERC accounts. I label these as A&G expenses because they are not associated with the operations and maintenance of the utility business. Service companies provide services to utility affiliates whose expenses are recorded in the 900 series of FERC accounts.

Mr. Effron contends the inclusion of comparison group expenses in some FERC accounts may not be applicable to the services provided by NCSC to Columbia. He cites one FERC account in particular—Account 908 Customer Assistance Expenses—in which some other utilities have a relatively large balance compared to Columbia's approximately $3.4 million in expenses for 2020.

Q. How did you address Mr. Effron's concerns?

A. I developed a revised comparison. For the comparison group, I included only the balances in the 900 series FERC accounts in which Columbia has a balance for 2020. I also excluded Account 908 even though Columbia has a balance in it for 2020. For the comparison group, I also included the balances in FERC accounts 922 and 929, both of which have credit balances and, in effect, reduce the comparison group's cost per customer. I did this even though Columbia has no balances in these accounts.

Q. What is Columbia's revised 2020 cost per customer?

A. The table below shows Columbia's 2020 cost per customer to be $274 using the revised criteria.

Analysis of 2020 Total Columbia Expenses

FERC Account		2020 Actual	In Comparison
902	Meter Reading Expenses	$ 609,051	$ 609,051
903	Customer Records and Collection Expenses	$ 6,712,939	$ 6,712,939
904	Uncollectible Accounts	$ 23,484,843	$ 23,484,843
905	Miscellaneous Customer Accounts Expenses	$ 2,597	$ 2,597
908	Customer Assistance Expenses	$ 3,446,010	
909	Informational and Instructional Expenses	$ 293,668	$ 293,668
910	Miscellaneous Customer Service and Info Ex	$ 1,508,476	$ 1,508,476
911	Supervision	$ 21,061	$ 21,061
912	Demonstrating and Selling Expenses	$ 321,060	$ 321,060
913	Advertising Expenses	$ 35,622	$ 35,622
920	Administrative and General Salaries	$ 26,975,624	$ 26,975,624
921	Office Supplies and Expenses	$ 5,621,005	$ 5,621,005
923	Outside Services Employed	$ 24,519,302	$ 24,519,302
924	Property Insurance	$ 137,961	$ 137,961
925	Injuries and Damages	$ 6,434,762	$ 6,434,762
926	Employee Pensions and Benefits	$ 12,325,027	$ 12,325,027
928	Regulatory Commission Expenses	$ 2,715,434	$ 2,715,434
930	General Advertising Expenses	$ 323,016	$ 323,016
930	Miscellaneous General Expenses	$ 3,990,768	$ 3,990,768
931	Rents	$ 4,800,299	$ 4,800,299
935	Maintenance of General Plant	$ 530	$ 530
	Total Expenses	$ 124,279,054	$ 120,833,044
	Columbia Customer Count (12/31/2020)		440,651
	Total Cost Per Customer		$ 274

Q. What is the comparison group's revised 2020 cost per customer?

A. Schedule PLB-1RJ shows the calculation of the comparison group's 2020 costs per customer using the revised criteria. Schedule PLB-2RJ shows the comparison of Columbia's 2020 cost per customer to those of the comparison group. Just like my original cost comparison, Columbia's cost is higher that the group average with several comparison group utilities higher than Columbia.

Q. What is Columbia's revised proforma 2021 cost per customer?

A. The table below shows Columbia's proforma 2021 cost per customer to be $298 using the revised criteria.

Proforma 2021 A&G Expenses per Customer

Columbia Total 2020 A&G Expenses		$ 120,833,044
Additional NCSC Allocation A&G Charges		
Total Additional Allocation	$ 11,400,000	
2020 Actual A&G Percentage	91.6%	
Additional A&G Amount	$ 10,444,740	$ 10,444,740
Total Post Divestiture A&G Charges		$ 131,277,783
Columbia Customer Count (12/31/2020)		440,651
Post Divestiture A&G Charges per Customer		$ 298

Q. What is the comparison group's revised proforma 2021 cost per customer?

A. Schedule PLB-3RJ shows the calculation of the comparison group's proforma 2021 costs per customer using the revised criteria. Schedule PLB-4RJ shows the comparison of Columbia's proforma 2021 cost per customer to those of the comparison group. Just like my original cost comparison, Columbia's cost is higher that the group average with several comparison group utilities higher than Columbia.

Q. Do the revised cost comparisons change your conclusion as to the reasonableness of NCSC charges to Columbia?

A. No, I believe NCSC charges to Columbia still show as reasonable. The revised cost comparisons are not materially different than the original comparisons in my Rebuttal Testimony. I believe I was conservative in my revised comparisons and addressed Mr. Effron's concerns.

Q. Does this conclude your testimony?

A. Yes.

Schedule PLB-1RJ

Columbia Gas of Pennsylvania, Inc.
Calculation of Comparison Group 2020 Total A&G Expenses Per Customer

2020 Actual	Total A&G Expenses	Total Customers	A&G Expenses per Customer
Appalachian Power Company	$ 125,257,506	960,162	$ 130
Atlantic City Electric Company	$ 180,074,890	562,054	$ 320
Baltimore Gas and Electric Company	$ 268,586,471	1,312,219	$ 205
Central Hudson Gas & Electric Company	$ 94,802,127	244,944	$ 387
Cleveland Electric Illuminating Company	$ 115,975,199	754,024	$ 154
Consolidated Edison Company	$ 775,335,531	3,517,291	$ 220
Dayton Power and Light Company	$ 118,775,752	281,989	$ 421
Delmarva Power & Light Company	$ 146,223,251	534,749	$ 273
Duke Energy Ohio, Inc.	$ 69,824,415	731,414	$ 95
Duquesne Light Company	$ 136,048,997	603,791	$ 225
Jersey Central Power & Light Company	$ 177,412,091	1145080	$ 155
Metropolitan Edison Company	$ 97,157,764	577,500	$ 168
Monongahela Power Company	$ 104,128,889	393,758	$ 264
New York State Electric & Gas Corporation	$ 253,580,179	907,336	$ 279
Niagara Mohawk Power Corporation	$ 449,009,227	1,421,431	$ 316
Ohio Edison Company	$ 125,686,501	1,058,301	$ 119
Ohio Power Company	$ 234,467,921	1,501,571	$ 156
Orange and Rockland Utilities, Inc.	$ 81,972,009	236,634	$ 346
PECO Energy Company	$ 295,892,743	1,671,433	$ 177
Pennsylvania Electric Company	$ 94,814,464	587,567	$ 161
Pennsylvania Power Company	$ 20,987,181	168,117	$ 125
Potomac Edison Company	$ 52,490,106	423,085	$ 124
Potomac Electric Power Company	$ 275,582,195	901,712	$ 306
PPL Electric Utilities Corporation	$ 230,337,647	1,457,376	$ 158
Public Service Electric and Gas Company	$ 297,359,519	2,033,919	$ 146
Toledo Edison Company	$ 43,048,272	313,654	$ 137
West Penn Power Company	$ 104,846,031	730,526	$ 144
Wheeling Power Company	$ 9,569,569	41,715	$ 229
Total	$ 4,979,246,447	25,073,352	$ 199

Source: FERC Form 1; Baryenbruch & Company, LLC, analysis

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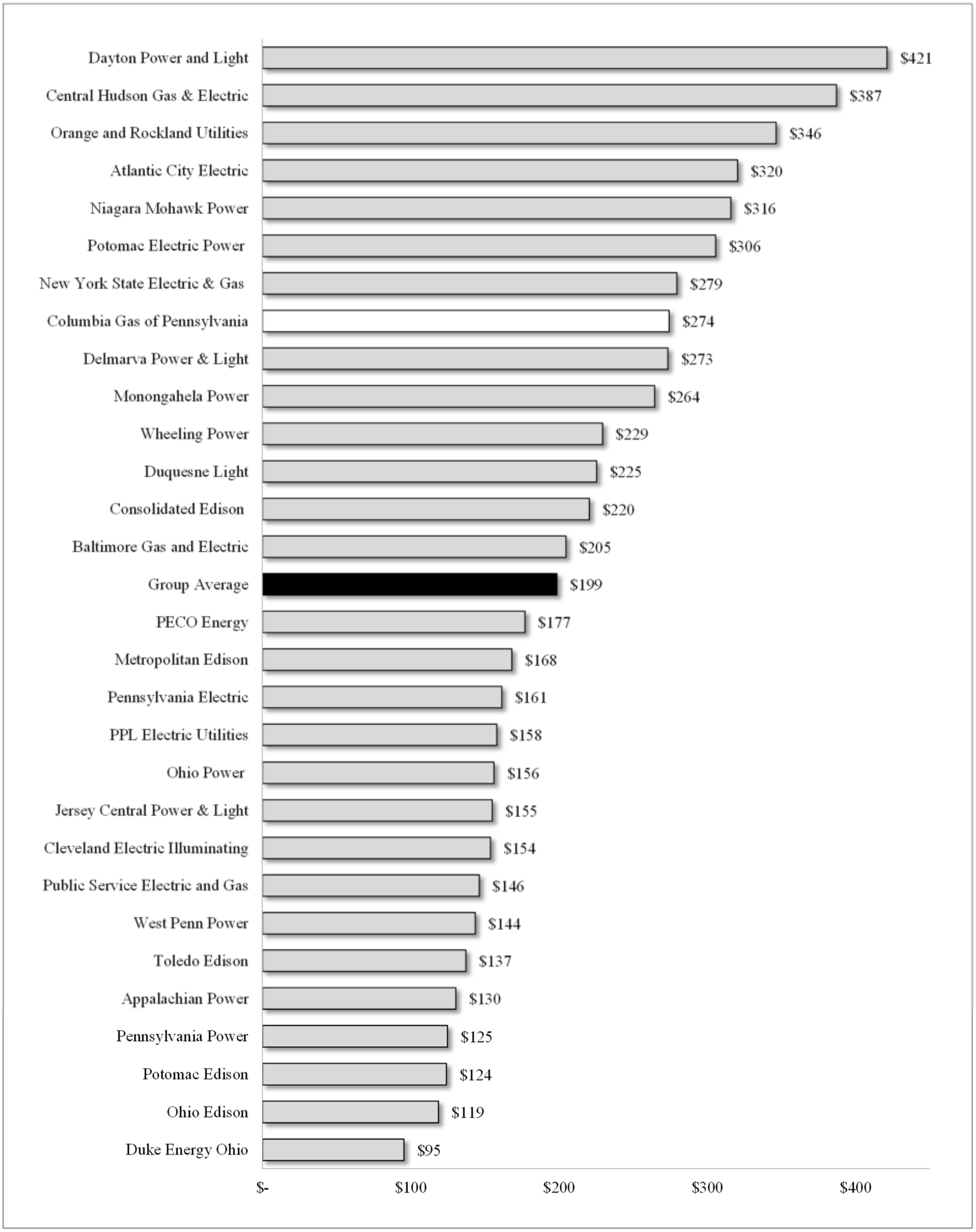
Schedule PLB-2RJ

Columbia Gas of Pennsylvania, Inc.
Comparison of 2020 Total A&G Expenses Per Customer



Source: FERC Form 1; Baryenbruch & Company, LLC Analysis

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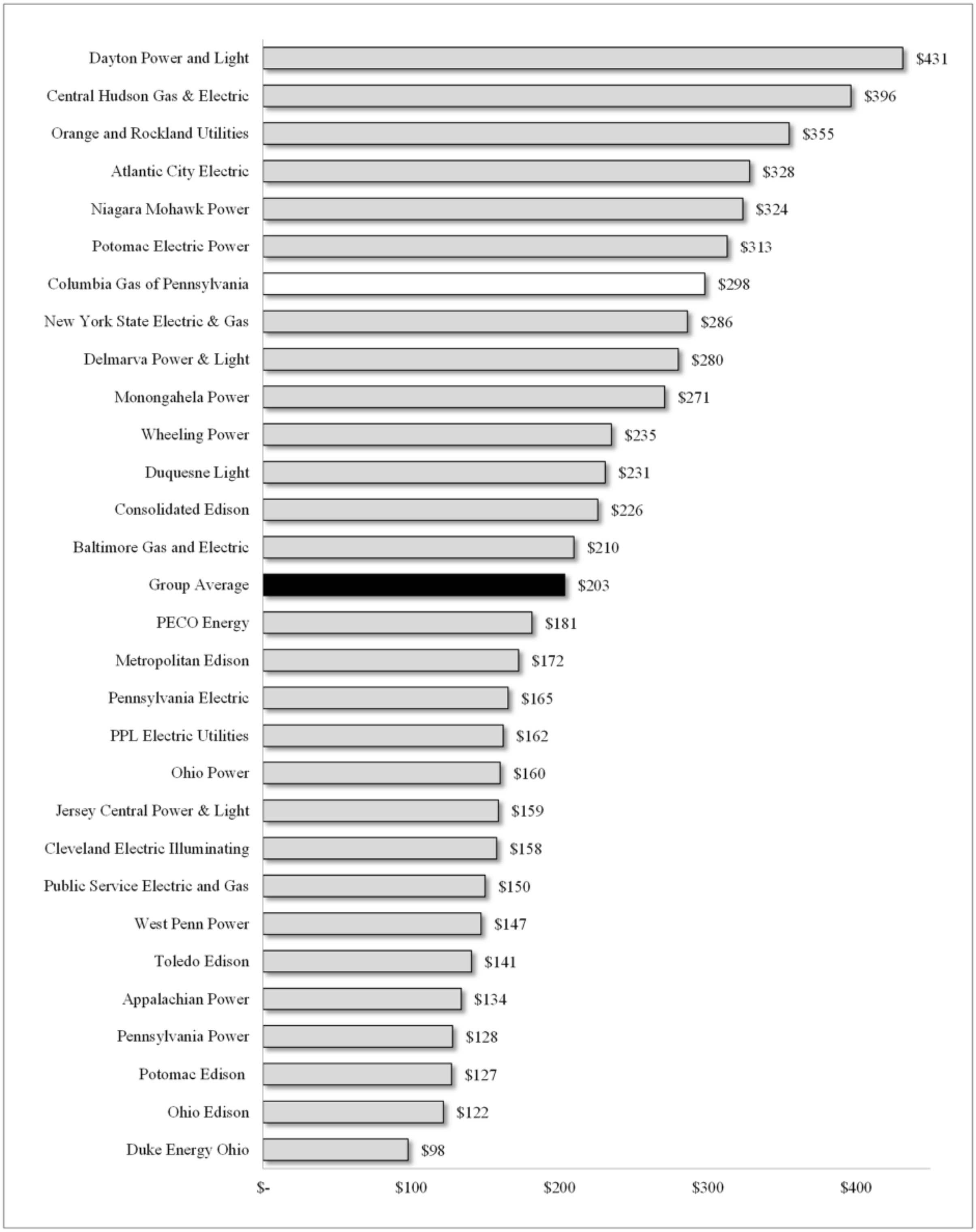
Columbia Gas of Pennsylvania, Inc.
Calculation of Comparison Group Proforma 2021 Total A&G Expenses Per Customer

2021 Proforma	2020 Total A&G Expenses per Customer	2021 Estimate Escalation Rate	2021 Estimate Escalated Cost/Customer
Appalachian Power Company	$ 130	2.44%	$ 134
Atlantic City Electric Company	$ 320	2.44%	$ 328
Baltimore Gas and Electric Company	$ 205	2.44%	$ 210
Central Hudson Gas & Electric Company	$ 387	2.44%	$ 396
Cleveland Electric Illuminating Company	$ 154	2.44%	$ 158
Consolidated Edison Company	$ 220	2.44%	$ 226
Dayton Power and Light Company	$ 421	2.44%	$ 431
Delmarva Power & Light Company	$ 273	2.44%	$ 280
Duke Energy Ohio, Inc.	$ 95	2.44%	$ 98
Duquesne Light Company	$ 225	2.44%	$ 231
Jersey Central Power & Light Company	$ 155	2.44%	$ 159
Metropolitan Edison Company	$ 168	2.44%	$ 172
Monongahela Power Company	$ 264	2.44%	$ 271
New York State Electric & Gas Corporation	$ 279	2.44%	$ 286
Niagara Mohawk Power Corporation	$ 316	2.44%	$ 324
Ohio Edison Company	$ 119	2.44%	$ 122
Ohio Power Company	$ 156	2.44%	$ 160
Orange and Rockland Utilities, Inc.	$ 346	2.44%	$ 355
PECO Energy Company	$ 177	2.44%	$ 181
Pennsylvania Electric Company	$ 161	2.44%	$ 165
Pennsylvania Power Company	$ 125	2.44%	$ 128
Potomac Edison Company	$ 124	2.44%	$ 127
Potomac Electric Power Company	$ 306	2.44%	$ 313
PPL Electric Utilities Corporation	$ 158	2.44%	$ 162
Public Service Electric and Gas Company	$ 146	2.44%	$ 150
Toledo Edison Company	$ 137	2.44%	$ 141
West Penn Power Company	$ 144	2.44%	$ 147
Wheeling Power Company	$ 229	2.44%	$ 235
Group Average	$ 199	2.44%	$ 203

1 Source: FERC Form 1; Baryenbruch & Company, LLC, analysis

Schedule PLB-4RJ

Columbia Gas of Pennsylvania, Inc.
Comparison of Proforma 2021 Total A&G Expenses Per Customer



1 Source: FERC Form 1; Baryenbruch & Company, LLC Analysis

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22495513v1

I&E Statement No. 1
Witness: John Zalesky

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Direct Testimony

of

John Zalesky

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

TAXES

TABLE OF CONTENTS

<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is John Zalesky. I am a Fixed Utility Financial Analyst in the Technical Division of the Pennsylvania Public Utility Commission's (Commission or PUC) Bureau of Investigation and Enforcement (I&E). My business address is Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. My education and professional background are set forth in the attached Appendix A.

Q. DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in rate proceedings. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. (Columbia or Company) and make recommended adjustments to the Company's proposed operating and maintenance (O&M) expenses for the fully projected future test year (FPFTY) ending December 31, 2022 and the proposed Federal Tax Reform Adjustment tariff.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. SUMMARIZE THE COMPANY'S OVERALL CLAIMED REVENUE REQUIREMENT.

A. The Company's base rate case filing was filed on March 30, 2021, requesting an increase of $98,278,240 to claimed present rate revenues of $661,206,723 resulting in a total overall revenue requirement of $759,484,963.[1]

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

	Company Claim	**I&E Recommended Allowance**	**I&E Adjustment**
Rate Case Expense	$1,060,000	$636,000	($424,000)
Labor Expense	$39,678,280	$39,095,208	($583,072)
Other Employee Benefits	$8,408,000	$7,189,609	($1,218,391)
Incentive Compensation	$2,445,000	$1,519,903	($925,097)
NCSC Incentive Compensation	$2,217,043	$1,434,284	($782,759)
FICA Taxes	$3,001,579	$2,894,111	($107,468)
PUC, OCA, OSBA Fees	$2,262,000	$2,008,792	($253,208)
Utilities and Fuel Used in Company Operations	$2,208,057	$2,089,038	($119,019)
Stock Rewards Expense	$2,776,164	$0	($2,776,164)
Total O&M Expense & Tax Adjustments			**($7,189,178)**

[1] Columbia Exhibit No. 102, Schedule 3, p. 3.

SUMMARY OF I&E OVERALL POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $715,310,045. This recommended revenue requirement represents an increase of $54,043,687 to the I&E adjusted present rate revenues of $661,266,358. This total recommended allowable increase incorporates my adjustments made in this testimony and those made in the testimony of I&E witnesses Christopher Keller[2] and Ethan Cline.[3]

A calculation of the I&E recommended revenue requirement is shown below:

Columbia Gas of PA Inc		TABLE I			
R-2021-3024296		INCOME SUMMARY			
	12/31/22	INVESTIGATION & ENFORCEMENT			
	Proforma	[---]			
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	661,206,723	59,635	661,266,358	54,043,687	715,310,045
Deductions:					
O&M Expenses	386,080,829	-7,189,178	378,891,651	613,595	379,505,246
Depreciation	109,970,328	0	109,970,328		109,970,328
Taxes, Other	3,715,938	0	3,715,938	0	3,715,938
Income Taxes:					
Current State	1,275,726	38,738	1,314,464	3,200,463	4,514,927
Current Federal	6,245,186	127,678	6,372,864	10,548,222	16,921,086
Deferred Taxes	15,685,797	0	15,685,797		15,685,797
ITC	-243,013	0	-243,013		-243,013
Total Deductions	522,730,791	-7,022,762	515,708,029	14,362,280	530,070,309
Income Available	138,475,932	7,082,397	145,558,329	39,681,407	185,239,736
Measure of Value	2,673,012,065	0	2,673,012,065	0	2,673,012,065
Rate of Return	5.18%		5.45%		6.93%

2 I&E Statement No. 2.

3 I&E Statement No. 3.

RATE CASE EXPENSE

Q. BRIEFLY EXPLAIN THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS A PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a utility's allowable claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by computing the average number of months between the filing dates of the utility's previous rate cases.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. The Company's projected total rate case expense of $1,060,000 is normalized over 12 months, resulting in an annual rate case expense claim of $1,060,000.[4]

Q. WHAT IS THE BASIS OF THE COMPANY'S CLAIM?

A. The Company's claim is based on estimated expenses for this case that reflects costs to be incurred for its capital witness, depreciation witness, outside counsel, and incremental costs associated with legal notices, employee expenses, and duplicating. The Company proposes to normalize the entire rate case expense over 12 months based on prior base rate case filing experience and its expectation of future base rate case filings.[5]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend that the Company's rate case expense be normalized over a period of 20 months resulting in an annual expense of $636,000 (($1,060,000 ÷ 20 months) x 12 months), or a reduction of $424,000 ($1,060,000 - $636,000) to the Company's claim.

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[4] Columbia Exhibit No. 104, Schedule 1, p. 4 and Schedule 2, p. 16.

[5] Columbia Statement No. 4, p. 21.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I disagree with the Company's claimed 12-month normalization period, as it is not supported by the Company's historic filing frequency. The proposed normalization period fails to properly rely upon historic data, and the Company did not provide support for a 12-month normalization period. As such, the proposed normalization period should be rejected.

In contrast to the Company's claimed 12-month normalization period, I recommend a 20-month normalization period. The normalization period of 20 months is a reasonable interval given the Company's actual base rate filing history over the most recent four base rate cases. Based on the following data, the Company has an average historic base rate case filing frequency of every 20 months when considering base rate cases filed since 2016:[6]

Docket No.	Date Filed	Filing Interval
R-2021-3024296	March 30, 2021	11 months
R-2020-3018835	April 24, 2020	25 months
R-2018-2647577	March 16, 2018	24 months
R-2016-2529660	March 18, 2016	

Using the Company's three most recent base rate case filing dates, the average interval is 20 months ((11 mo. + 25 mo. + 24 mo.) ÷ 3 intervals). The Company's requested 12-month recovery period is unsupported. Thus, a 12-month normalization period should be rejected, as it would result in an unreasonable increase in rates.

[6] I&E Exhibit No. 1, Schedule 1, p. 1.

Q. HAVE OTHER UTILITIES BEEN GRANTED A NORMALIZATION PERIOD BASED ON SPECULATION OF FUTURE FILINGS, AND IF SO, WHAT WAS THE RESULT?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation (PPL) permission to normalize its rate case expense over a 24-month period based on PPL's representations regarding its expected timing of future base rate case filings.[7] That base rate case was filed on March 30, 2012; however, despite PPL's representations, PPL did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing. It should be noted that I&E's recommended normalization period in the 2012 PPL proceeding was a 32-month interval based on PPL's historic filing frequency.[8] The I&E recommendation in that instance produced a much more accurate result than relying on PPL's stated future intention to file a rate case.

Q. ARE THERE ANY COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. Since the 2012 PPL proceeding, there have been three cases in which the Commission has supported I&E's recommendation based upon historic filing frequency. In a base rate case filed by Emporium Water Company, the

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[7] *PA. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, pp. 47-48 (Order Entered December 28, 2012).

[8] I&E Statement No. 2, pp. 13-14 at Docket No. R-2012-2290597.

Commission adopted the I&E recommended historic filing frequency finding in favor of I&E's recommended five-year normalization period based on a historic average filing frequency that was rounded down from 64 months.[9] Additionally, in the City of DuBois base rate case, the Commission agreed with I&E's recommendation to use a historic filing frequency finding in favor of I&E's recommended 64-month normalization period, which matched the actual historic filing frequency.[10]

Finally, and most recently, in the 2020 Columbia Gas base rate proceeding, the Commission adopted I&E's recommendation and indicated that the normalization period should align with the historic data rather than the Company's intent to file its next rate case.[11]

LABOR EXPENSE

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR LABOR EXPENSE?

A. The Company's labor claim includes annualized gross wages for regular payroll, overtime, premium pay, and net affiliate labor transferred.[12]

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[9] *PA PUC v. Emporium Water Company*, Docket No. R-2014-2402324, p. 50 (Order Entered January 28, 2015).

[10] *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

[11] *PA PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

[12] Columbia SDR GAS-RR-026, Attachment A.

Q. WHAT IS THE COMPANY'S CLAIM FOR LABOR EXPENSE?

A. The Company's FPFTY claim for labor expense is $39,678,280.[13]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company started with its HTY labor expense for 767 employees and made budget adjustments and ratemaking adjustments for determining FTY and FPFTY labor expense based on 798 employees.[14] The budget and ratemaking adjustments relate primarily to budgeted wage increases and projected increases in payroll expense for additional employees in the FTY and FPFTY.[15]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $39,095,208 for labor expense, or a reduction of $583,072 ($39,678,280 - $39,095,208) to the Company's claim.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. My recommendation is based on an employee vacancy adjustment. Normally, companies have a certain level of employee vacancies on a day-to-day operating

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[13] Columbia Exhibit No. 104, Schedule 1, p. 4 and SDR-GAS-RR-026, Attachment A.
[14] Columbia Statement No. 4, pp. 8-9 and Columbia Statement No. 9, p. 9.
[15] Columbia Statement No. 9, pp. 8-9; Exhibit No. 104, Schedule 2, p. 1; and SDR-GAS-RR-026, Attachment A.

basis due to retirements, resignations, transfers, layoffs, etc., that are unpredictable. Such vacancies will yield an annual savings in the Company's payroll and benefit costs that need to be reflected for ratemaking.

It is, unreasonable to assume that the Company will maintain or attain 100% full staffing of 798 employees in the FPFTY. There will always be search and placement time involved in filling employee vacancies as per the Company's vacancy-filling or hiring procedures described in the Company's response to I&E-RE-11-D (E).[16]

Furthermore, it is worth noting that the highest monthly number of total employees by month from December 2017 through April 2021 is 784, which is the basis of my adjustment.[17] Finally, and most recently, in the 2020 Columbia Gas base rate proceeding, the Commission adopted OCA's recommendation to reflect an employee complement at the actual high recorded by the Company.[18]

Q. EXPLAIN HOW YOU CALCULATED THE NORMAL EMPLOYEE VACANCY RATE AND THE CORRESPONDING ADJUSTMENT TO LABOR EXPENSE.

A. My recommended payroll and benefits expense reduction is based on 14 employee vacancies at the average payroll and benefits cost per employee. Based on the Company's responses to OCA-I-21 and OCA-VII-13, I assumed an FPFTY

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16 I&E Exhibit No. 1, Schedule 3, p. 6.
17 I&E Exhibit No. 1, Schedule 2, p. 4 and Schedule 3, p. 3.
18 *PA PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 71-72 (Order Entered February 19, 2021).

employee count of 784, or the highest count of any month listed (eight months of HTY and five months of FTY).[19] Next, I considered the Company's claim of 798 employees for both the FTY and the FPFTY in calculating a vacancy rate of 14 (798 – 784). Then, I calculated the incremental O&M labor expense per employee of $41,648 by dividing $1,957,451 for Budgeted Vacancies by 47 for the Budgeted Vacancies headcount ($1,957,451 ÷ 47).[20] Finally, I multiplied the vacancy rate of 14 by the incremental O&M labor expense per employee of $41,648 to calculate my recommended adjustment of $583,072 ($41,648 x 14).

<u>OTHER EMPLOYEE BENEFITS</u>

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR OTHER EMPLOYEE BENEFITS?

A. Other employee benefits expense includes claims for benefits such as medical, dental, vision, life insurance, long term disability, 401K plan, and profit sharing benefits.[21]

Q. WHAT IS THE COMPANY'S CLAIM FOR OTHER EMPLOYEE BENEFITS?

A. The Company's claim for other employee benefits expense is $8,408,000.[22]

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19 I&E Exhibit No. 1, Schedule 2, pp. 2 and 4.
20 Columbia SDR GAS-RR-026, Attachment A.
21 I&E Exhibit No. 1, Schedule 4, p. 2.
22 Columbia Exhibit No. 104, Schedule 1, p. 4.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has based its FPFTY claim on "amounts provided to the Company from outside third party consultant to reflect updated benefits costs."[23]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $7,189,609 for other employee benefits expense, or a reduction of $1,218,391 ($8,408,000 - $7,189,609) to the Company's claim.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. My recommendation is based on a three-year average historical percentage of Other Employee Benefits to Labor multiplied by my labor recommendation.

Q. SUMMARIZE YOUR OVERALL RECOMMENDED ADJUSTMENT TO OTHER EMPLOYEE BENEFITS EXPENSE.

A. First, I calculated the historical ratios of other employee benefits to total labor for 2018 of 18.33% ($5,906,148 ÷ $32,215,808), 2019 of 19.19% ($6,931,682 ÷ $36,130,190), and HTY 2020 of 17.66% ($6,712,213 ÷ $38,012,528).[24] Next, I calculated the average historical ratio of other employee benefits to total labor of

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23 I&E Exhibit No. 1, Schedule 5, pp. 2-3.

24 Columbia Exhibit No. 4, Schedule 1, p. 2.

18.39% ([18.33% + 19.19% + 17.66%] ÷ 3). Finally, I used the average historical ratio of 18.39% and multiplied it by my labor recommendation of $39,095,208 for a recommended allowance of $7,189,609 (18.39% x $39,095,208).

It must be noted that the Company's claim is unsupported. The Company has provided no supporting documentation for its claim; it merely points to an undisclosed third-party consultant. Therefore, my recommendation based on a historic percentage of labor should be accepted.

INCENTIVE COMPENSATION

Q. WHAT IS INCENTIVE COMPENSATION?

A. Incentive compensation consists of payments made to eligible employees that are in addition to the employees' base salaries and wages. An incentive compensation payout is generally based on the attainment of key performance indicators established by the Company or affiliated/parent company.

Q. WHAT IS THE COMPANY'S CLAIM?

A. The Company's incentive compensation claim is $2,445,000.[25]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The payment of cash-based incentive compensation is based on achievement of performance targets/triggers during the performance period, such as financial (net

[25] Columbia Exhibit 104, Schedule 1, p. 4.

operating earnings per share (NOEPS)), customer care, and safety measures as detailed in the parent company's incentive plan, "NiSource Inc. - 2010 Omnibus Incentive Plan."[26] According to the Company's response to OCA-I-37, "NiSource did not achieve expected NOEPS target by Nov 2020. 2021 is planned at target levels for incentive compensation."[27] The Company adjusted its FTY claim for inflation in order to arrive at its FPFTY claim.[28]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of $1,519,903 for incentive compensation, or a reduction of $925,097 ($2,445,000 - $1,519,903) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a three-year historic average of incentive compensation payouts. In the HTY ended November 30, 2020, the Company's corrected normalized incentive compensation was $1,900,925.[29] Additionally, the incentive compensation amounts for the 12-months ended November 30, 2018, and November 30, 2019 were $1,521,149 and $1,472,179, respectively.[30]

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[26] Columbia SDR-GAS-RR-027, Attachments A through E.
[27] I&E Exhibit No. 1, Schedule 5, p. 2.
[28] I&E Exhibit No. 1, Schedule 5, p. 3.
[29] I&E Exhibit No. 1, Schedule 6, p. 1.
[30] Columbia Exhibit 4, Schedule 1, p. 2.

Considering the variability in incentive payouts over the last three years, I utilized an average of incentive compensation in my recommendation, which will even out historic highs and lows. Accordingly, I recommend an allowance of $1,519,903 (($1,521,149 + $1,472,179 + $1,566,381) ÷ 3).

Based on the Company's response to I&E-RE-15-D (A) there is no specific number of eligible employees or base payroll for determining incentive payments.[31] Also, in its response to I&E-RE-16-D (C) the Company states that the performance triggers must be met before any incentive compensation is funded.[32] Therefore, utilizing a three-year historic average is justified in anticipating future results.

Additionally, as the determination of incentive compensation relies heavily on the NOEPS trigger with a weighting of 75%/85%,[33] and as the Company makes it very clear in its response to I&E-RE-16-D (C) that triggers must be met before any incentive compensation is funded,[34] there is little discernable benefit to ratepayers in the Company's incentive compensation program. Accordingly, allowing a three-year normalized amount is more than reasonable.

<u>NCSC INCENTIVE COMPENSATION</u>

Q. WHAT IS NCSC INCENTIVE COMPENSATION?

A. NCSC incentive compensation consists of payments made to eligible employees of

[31] I&E Exhibit No. 1, Schedule 7, p. 2.
[32] I&E Exhibit No. 1, Schedule 10, p. 2.
[33] Columbia filing SDR RR-027, Attachment B, pp. 2-3.
[34] I&E Exhibit No. 1, Schedule 10, p. 2.

NCSC that are in addition to the employees' base salaries and wages. An incentive compensation payout is generally based on the attainment of key performance indicators established by the Company or the parent company.

Q. WHAT IS THE COMPANY'S CLAIM?

A. The Company's incentive compensation claim is $2,217,043.[35]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of $1,434,284 for incentive compensation, or a reduction of $782,759 ($2,217,043 - $1,434,284) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Similar to my recommendation for incentive compensation in the above section, my recommendation is based on a three-year historic average of incentive compensation payouts. In the 12-months ended November 30, 2020, the Company's NCSC incentive compensation was $63,025.[36] Additionally, the incentive compensation amounts for the 12-months ended November 30, 2018, and November 30, 2019 were $2,509,880 and $1,729,947, respectively.[37] Considering the decreases in incentive payouts over the last three years, I generously utilized an average of incentive compensation in my recommendation,

[35] I&E Exhibit No. 1, Schedule 7, p. 3.
[36] I&E Exhibit No. 1, Schedule 7, p. 2.
[37] I&E Exhibit No. 1, Schedule 7, p. 2.

despite a downward trend. Accordingly, I recommend an allowance of $1,434,284 (($2,509,880 + $1,729,947 + $63,025) ÷ 3).

FICA TAXES

Q. WHAT IS FICA TAX EXPENSE?

A. The Federal Insurance Contributions Act (FICA) tax is a payroll tax imposed on both employers and employees to fund the social security and Medicare programs that provide benefits to retirees, the disabled, and survivors of deceased workers. The employers' portion of the 2020 social security tax rate is 6.2%, and the corresponding Medicare tax rate is 1.45%. The social security tax has a wage limit in 2020 of $137,700.[38]

Q. WHAT IS THE COMPANY'S CLAIM?

A. The Company's FICA tax expense claim is $3,001,579.[39]

Q. WHAT IS THE BASIS OF THE COMPANY'S CLAIM?

A. The Company's claim is based on the HTY FICA experienced rate of 7.1257% for the employers' share of FICA taxes.[40]

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[38] https://www.irs.gov/taxtopics/tc751, accessed on May 19, 2021.
[39] Columbia Exhibit 106, Schedule 2, p. 2.
[40] Columbia Exhibit 106, Schedule 2, p. 3.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. While I am not disputing the Company's 7.1257% experienced rate, it is necessary to make an adjustment to the Company's FICA tax expense claim that corresponds to my labor and incentive compensation recommendations as discussed above.

Q. WHAT IS YOUR RECOMMENDATION FOR FICA TAXES?

A. I recommend a FICA tax expense allowance of $2,894,111 or a reduction of $107,468 ($3,001,579 - $2,894,111) to the Company's claim.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. My recommended adjustments to labor expense and incentive compensation necessitate a corresponding reduction to the Company's FICA tax expense. In determining my recommended adjustment, I applied the Company's HTY FICA experienced rate of 7.1257%.[41]

Q. HOW DID YOU COMPUTE YOUR RECOMMENDATION FOR FICA TAXES?

A. I multiplied my total recommended labor expense and incentive compensation amount of $40,615,111 ($39,095,208 + $1,519,903) by the Company's HTY FICA

[41] Columbia Exhibit 106, Schedule 2, p. 3.

experienced rate of 7.1257% to determine my recommendation of $2,894,111 ($40,615,111 x 0.071257) for FICA tax expense.

PUC, OCA, OSBA FEES

Q. WHAT ARE PUC ASSESSMENTS?

A. PUC assessments are based on a percentage of intrastate gross revenues and charged to regulated utility companies by the PUC on behalf of regulatory entities such as the PUC, the Office of Consumer Advocate (OCA), and the Office of Small Business Advocate (OSBA), as well as a General Safety Assessment. These assessments are used to fund the expenditures of such entities for the following year.

Q. WHAT IS THE COMPANY'S CLAIM FOR PUC, OCA, AND OSBA FEES?

A. The Company's claim for PUC, OCA, and OSBA assessment fees is $2,262,000.[42]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. According to the Company's response to OCA-I-37, the claim was, "based off budget to actual assessment for the HTY and reflect the most up to date invoice factors in the Assessment Notice received by the Company in September 2020."[43] The Company also points to the PUC Assessment Factors tab which provides the

[42] Columbia Exhibit No. 104, Schedule 1, p. 4.
[43] I&E Exhibit No. 1, Schedule 5, p. 2.

total fees paid in the years 2015 through 2020 and an average of these amounts of $2,177,442.[44]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $2,008,792, or a reduction of $253,208 ($2,262,000 - $2,008,792) to the Company's claim.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. I am basing my recommendation on the most recent general assessment notice of $2,008,792.[45] It is more prudent to rely on the most up-to-date data for PUC assessments than to rely on the Company's increase with no stated basis or calculation. Furthermore, in the 2020 Columbia Gas base rate proceeding, the Commission adopted I&E's recommendation and indicated that relying on the most recent invoice is appropriate.[46]

Further, the Company has not provided a calculation for its claim. The 2015-2020 average of $2,177,442 does not tie to the Company's claim.[47] Thus, the Company's claim is unsupported, and my recommendation should be adopted.

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[44] I&E Exhibit No. 1, Schedule 5, p. 6.
[45] Columbia Exhibit 4, Schedule 1, p. 2 and Schedule 2, p. 18.
[46] *PA PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 76-77 (Order Entered February 19, 2021).
[47] I&E Exhibit No. 1, Schedule 5, p. 6.

UTILITIES AND FUEL USED IN COMPANY OPERATIONS

Q. WHAT IS INCLUDED IN UTILITIES AND FUEL USED IN COMPANY OPERATIONS?

A. Gas Used in Company Operations, Gas Left on for Connect, cable, Electric, Gas, Mobile Cellular Pagers, Telephone, Water and Sewage, and Telecommunications are included in this account.[48]

Q. WHAT IS THE COMPANY'S CLAIM FOR UTILITIES AND FUEL USED IN COMPANY OPERATIONS?

A. The Company's FPFTY claim is $2,208,057.[49]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company based its claim on its normalized HTY with budget and rate making adjustments for the FTY and FPFTY.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $2,089,038, or a reduction of $119,019 ($2,208,057 - $2,089,038) to the Company's claim.

[48] I&E Exhibit No. 1, Schedule 8, p. 3.
[49] Columbia Exhibit No. 104, Schedule 1, p. 4.

Q. WHAT IS THE BASIS OF YOUR CLAIM?

A. The Company discovered an error in response to an interrogatory which resulted in adjustments of $58,964 to the FTY and $60,055 to the FPFTY.[50] Because the FTY is the basis for the FPFTY, the total adjustment to Company's FPFTY claim is $119,019 ($58,964 + $60,055).

<u>COVID-19 RELATED UNCOLLECTIBLE EXPENSE</u>

Q. WHAT IS UNCOLLECTIBLE EXPENSE?

A. Uncollectible accounts are specific receivables that are determined to be uncollectible, in whole or in part, either because the debtors do not pay or because the creditor finds it impracticable to enforce payment. Those accounts deemed uncollectible are charged against income as uncollectible accounts expense.

Q. HOW DO UTILITIES GENERALLY RECOGNIZE UNCOLLECTIBLE ACCOUNTS EXPENSE FOR RATEMAKING PURPOSES?

A. Generally, for ratemaking purposes, utilities compute uncollectible accounts expense on an annual prospective basis. While the uncollectible accounts expense is a prospective claim, the proper calculation begins with a historic analysis of actual net write-offs to gross revenues to develop a historic write-off ratio. Thus, net write-offs are gross write-offs less recoveries of amounts previously written

[50] I&E Exhibit No. 1, Schedule 8, p. 4.

off. This ratio is applied to projected revenues to determine the proper prospective allowance. Normally, the historic analysis is based on several years of data.

Q. HOW HAS THE COMPANY TREATED COVID-19 RELATED UNCOLLECTIBLE EXPENSE?

A. In accordance with the Secretarial Letter issued May 13, 2020 at Docket No. M-2020-3019775 the Company has deferred incremental uncollectible expense of $5,579,245 through December 2020. The Company proposes amortizing this deferral over five years.[51] The Company is also requesting permission to continue deferring incremental uncollectible expenses via a regulatory asset and updating the amount in a future base rate case.[52] Finally, the Company is requesting permission to update the regulatory asset until the final impacts to customer accounts have been determined.[53]

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S PROPOSED HANDLING OF COVID-19 RELATED UNCOLLECTIBLE EXPENSE?

A. I accept the Company's amortization period of five years for its deferred incremental uncollectible expense through December 2020. However, I disagree with the Company's proposed ongoing updates to the regulatory asset for continued deferrals until some unknown future date. In contrast, I recommend an

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[51] Columbia Statement No. 4, p. 46, lines 1-7.
[52] Columbia Statement No. 4, p. 46, lines 12-16.
[53] Columbia Statement No. 4, p. 46, lines 19-20.

end to the incremental deferral of expenses as of the effective date of new rates at the conclusion of the base rate proceeding. It is inappropriate for Columbia to continue updating the regulatory asset related to uncollectibles indefinitely. Although the Commission has authorized the creation of a regulatory asset for any incremental expenses related to the recent order,[54] it does not necessitate the continued treatment for uncollectibles.

<u>STOCK REWARDS EXPENSE</u>

Q. WHAT IS STOCK REWARDS EXPENSE?

A. According to the Company's response to OCA-I-25, "Stock based compensation is a common element of compensation at key management levels of organizations and is a part of NiSource's total compensation package designed to attract and retain executive talent."[55]

Q. WHAT IS THE COMPANY'S CLAIM FOR STOCK REWARDS EXPENSE?

A. The Company's total FPFTY claim is $2,776,164, composed of $559,121 for Columbia and $2,217,043 for NCSC Stock Comp Shared Service Expense Allocated.[56]

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[54] *Public Utility Service Termination Moratorium,* Docket No. M-2021-3019244, Order, p. 6 (Order Entered March 18, 2021).

[55] I&E Exhibit No. 1, Schedule 9, p. 1.

[56] I&E Exhibit No. 1, Schedule 9, p. 1.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company adjusted its prior year stock reward values based on future reward recipients, estimated target reward values, and 2021 stock reward program design to determine its claim.[57]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend disallowance of the Company's stock rewards expense claim $2,776,164 in its entirety.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Stock rewards are a type of incentive compensation linked to financial goals and targets such as earnings per share, rate of return on equity, or appreciation of the parent company's common stock. These goals are specifically shareholder-oriented goals, not ratepayer goals. Thus, stock rewards should not be funded by ratepayers. Allowing this claim in rates would result in higher rates and revenues at the expense of ratepayers which would directly boost financial goals. It must also be noted that stock rewards are limited to executives,[58] and therefore it is not immediately obvious how stock rewards are related to safe and reliable service.

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[57] I&E Exhibit No. 1, Schedule 9, p. 1.
[58] I&E Exhibit No. 1, Schedule 9, p. 1.

FEDERAL TAX REFORM ADJUSTMENT TARIFF

Q. WHAT IS THE PROPOSED FEDERAL TAX REFORM ADJUSTMENT (FTRA) TARIFF?

A. The Company is proposing the addition of a Federal Tax Reform Adjustment to its tariff to provide for adjustments to base rates for the effect of future increases or decreases to the federal corporate income tax rate.[59] This proposal addresses both current and deferred income taxes and the accumulated deferred income taxes included as a component of rate base.[60]

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED FTRA TARIFF?

A. Company witness Jennifer Harding states that changes in the Federal income tax rate can be material and abrupt which results in volatility as demonstrated by the enactment of the Tax Cuts and Jobs Act of 2017. Therefore, the Company is preemptively proposing the FTRA to counteract any changes to the federal income tax rate.[61]

Q. DO YOU AGREE WITH ESTABLISHING THE PROPOSED FTRA TARIFF?

A. No. I recommend the Company's proposal be disallowed.

[59] Columbia Statement No. 10, p. 15.
[60] Columbia Statement No. 10, p. 16.
[61] Columbia Statement No. 10, p. 15.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. Without getting into a political debate in testimony, the Company cannot say with any certainty if/when an increase to the federal corporate income tax rate will take effect. Furthermore, since the Commission and its advisory staff have very recently dealt with the reduction in the federal corporate income tax rate due to changes related to the Tax Cuts and Jobs Act starting January 1, 2018, I believe the Commission will provide adequate and timely guidance on a statewide basis to affected regulated utilities if such a change in the tax rate takes effect. Columbia should be required to await such guidance, particularly since any changes to the federal income tax rates are merely speculative at this time.

Q. IN THE EVENT THAT THE COMMISSION DECIDES TO ALLOW THE COMPANY TO ESTABLISH THE FTRA TARIFF, DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes. I believe it would be critical not to allow rate adjustments via the proposed surcharge mechanism for impacts associated with deferred federal income taxes (i.e., excess accumulated deferred income taxes), as the Company has proposed,[62] and those changes should only be allowed to occur in the Company's base rate case filed after any tax rate changes. The proposed FTRA rider should only be allowed for the *current* federal income tax expense portion of the change (similar to how the changes associated with the Tax Cuts and Jobs Act were handled by the

[62] Columbia Statement No. 10, p. 16.

Commission). Deferred taxes require more scrutiny of regulators and statutory parties due to subjectivity in certain circumstances in determining the proper normalization periods, particularly for tax differences associated with non-protected assets that are not subject to the strict requirements of IRS normalization rules. However, I strongly recommend that the Commission require the Company to await statewide guidance if/when any potential future corporate income tax rate changes occur.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JOHN E. ZALESKY

PROFESSIONAL EXPERIENCE AND EDUCATION

EMPLOYMENT

Pennsylvania Public Utility Commission — **Harrisburg, PA**
Fixed Utility Financial Analyst — *December 2017-Present*

Pennsylvania Office of the Budget, Comptroller Operations — **Harrisburg, PA**
Executive Accounting Specialist — *2017*

Mount 2000 High School Retreat — **Emmitsburg, MD**
Finance Coordinator — *2016*

Pennsylvania Department of Revenue, Corporation Taxes — **Harrisburg, PA**
Taxing Officer — *2012-2014*

David K Mitchell Financial — **Nanticoke, PA**
Intern — *2011*

EDUCATION & TRAINING

National Association of Regulatory Utility Commissioners — **Clearwater Beach, FL**
46th Eastern NARUC Utility Rate School — October 2018

Mount St. Mary's University — **Emmitsburg, MD**
Master of Arts in Philosophical Studies — *Class of 2017*
Thesis: Whether Social Media are Beneficial for Human Friendship

Harrisburg Area Community College — **Harrisburg, PA**
Accounting — *Class of 2013*
Associate in Arts in Business Studies, Highest Honors

The Pennsylvania State University — **University Park, PA**
Smeal College of Business, *Schreyer Honors College* — *Class of 2012*
Bachelor of Science in Finance, With Highest Distinction
Minors in Spanish, International Studies, and International Business
Thesis: Present Value Analysis of Pennsylvania Tuition Subsidies

EXPERIENCE

I have provided assistance with, worked on, or written testimony for the following proceedings:

- Docket No. R-2021-3023618 – UGI Utilities, Inc. – Electric Division*
- Docket No. R-2020-3022134 – Pike County Light & Power (Gas)*
- Docket No. R-2020-3022135 – Pike County Light & Power (Electric)*
- Docket No. P-2020-3021191 – Peoples Natural Gas Tax Repair Election*
- Docket No. R-2020-3020919 – Audubon Water Company*
- Docket No. R-2020-3018835 – Columbia Gas of Pennsylvania, Inc.*
- Docket No. P-2020-3019290 – PECO Default Service Plan
- Docket No. R-2019-3015162 – UGI Utilities, Inc. – Gas Division*
- Docket No. A-2019-3012241 – Veolia Acquisition
- Docket No. R-2019-3010958 – Twin Lakes Utilities, Inc.*
- Docket No. R-2019-3009559 – Eaton Sewer and Water – Wastewater
- Docket No. R-2019-3009567 – Eaton Sewer and Water – Water
- Docket No. R-2019-3009624 – PECO Energy 1307(f)
- Docket No. R-2019-3006904 – Newtown Artesian Water Company*
- Docket No. A-2018-3006061, A-2018-3006062, and A-2018-3006063 – Aqua-Peoples Acquisition*
- Docket No. R-2018-3003558 – Aqua Pennsylvania, Inc.
- Docket No. R-2018-3003561 – Aqua Pennsylvania Wastewater, Inc.
- Docket No. R-2018-3001306 – Hidden Valley Utility Services – Water Division*
- Docket No. R-2018-3001307 – Hidden Valley Utility Services – Wastewater Division*
- Docket No. R-2018-3000164 – PECO Energy – Electric*
- Docket No. R-2018-3001568 – PECO Energy – Gas (1307(f))
- Docket No. R-2017-2640058 – UGI Utilities, Inc. – Electric Division

*Testimony Submitted

I&E Exhibit No. 1
Witness: John Zalesky

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Exhibit to Accompany

the

Direct Testimony

of

John Zalesky

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

TAXES

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-004-D:

Reference Columbia Exhibit No. 104, Schedule 2, p. 16 concerning the rate case expense normalization of $1,060,000. Provide the requested rate case expense and *the actual total dollar amount* expended for the settled rate cases at:

A. Docket No. R-2016-2529660 (filed March 18, 2016);

B. Docket No. R-2018-2647577 (filed March 16, 2018);

C. Docket No. R-2020-3018835 (filed April 24, 2020); and

A detailed breakdown for *actual incurred expenses* for each of the above cases by category (e.g., Gannett Fleming, Moul and Associates, Post and Schell, Legal Notices, Travel, and Miscellaneous: Supplies, Courier, etc.).

Response:

Please see I&E-RE-004-D Attachment A for the requested information.

I&E Exhibit No. 1
Schedule No. 1
Page 2 of 2

Columbia Gas of Pennsylvania, Inc.
Summary of Rate Case Expense
By Docket #

Line No.	Description	R-2016-2529660	R-2018-2647577	R-2020-3018835
		Amount ($)	**Amount ($)**	**Amount ($)**
1	Gannett Fleming	19,473	35,067	38,185
2	Moul and Associates	64,843	56,396	96,188
3	Post and Schell	425,426	476,870	572,287
4	Concentric Energy Advisors	-	-	40,000
5	James Cawley	-	-	18,600
6	Legal Notices	34,139	20,770	15,051
7	Travel Expense	2,062	9,224	1,085
8	Miscellaneous: Supplies, Courier, Etc.	1,493	13,259	1,126
9	**Total**	$ 547,436	$ 611,586	$ 782,522
10	**Amount Requested 1_/**	$ 1,030,000	$ 1,030,000	$ 1,060,000
11	**Amount Approved 2_/**	$ -	$ -	$ 636,000

1_/ Requested amounts reflect the budgeted amount for a fully litigated case, however the 2016 and the 2018 cases were settled prior to hearings.
2_/ A 20 month amortization period was approved versus the 12 month requested.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-021:

Referring to Exhibit No. 4, Schedule 2, Page 2, please provide the number of employees in each labor classification by month from April 2020 until the latest month available.

Response:

Please see Attachment A for the requested information.

Line No.		Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
1	Exempt	179	178	179	178	178	180	171	174	173	173	172	168
2	Clerical	96	96	95	96	96	96	95	95	94	93	92	93
3	Manual - Union	493	491	490	486	485	484	483	483	484	478	482	488
4	Manual - Nonunion	16	16	16	16	15	15	15	15	15	15	15	15
5	**Total**	**784**	**781**	**780**	**776**	**774**	**775**	**764**	**767**	**766**	**759**	**761**	**764**

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 7

Question No. OCA 7-013:

Please update the response to OCA 1-021.

Response:

Please see Attachment A to this response for the requested information.

Line No.		Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
1	Exempt	179	178	179	178	178	180	171	174	173	173	172	168
2	Clerical	96	96	95	96	96	96	95	95	94	93	92	93
3	Manual - Union	493	491	490	486	485	484	483	483	484	478	482	488
4	Manual - Nonunion	16	16	16	16	15	15	15	15	15	15	15	15
5	**Total**	**784**	**781**	**780**	**776**	**774**	**775**	**764**	**767**	**766**	**759**	**761**	**764**

		Apr-21
6	Exempt	174
7	Clerical	95
8	Manual - Union	487
9	Manual - Nonunion	15
10	Total	**771**

I&E Exhibit No. 1
Schedule No. 2

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-011-D:

Reference Columbia Standard Data Requests GAS-RR-020, SDR-RR-021, and SDR-RR-026 concerning employee counts and employee additions. Provide the following:

A. Monthly total number of full-time employees by category (clerical labor, exempt labor, manual non-union, and manual union) and monthly total labor cost for 12-months ended November 30, 2018, November 30, 2019, November 30, 2020, and actual amounts for December 2020 through March 2021;

B. Total number of employees' retirement/resignation/termination/ transfer (normal vacancies) by employee category (union, non-union, and non-union temporary) anticipated by month in FTY and FPFTY;

C. Number of normal vacancies by month for unfilled open positions in for 12-months ended November 30, 2018, November 30, 2019, November 30, 2020, and actual amounts for December 2020 through March 2021;

D. Number of new employees hired, hiring dates, and their payroll details (with employee names redacted) for the HTY 2020;

E. Describe the procedures needed to fill vacant positions (e.g., approved by upper management, positions advertised, interviews conducted, etc.);

F. State whether all additional positions anticipated to be filled in 2020 are approved by upper management; and

G. Identify and quantify any changes in vacancies, vacancy rates, or change of labor needs and assumptions for the HTY, FTY, and FPFTY due to the COVID-19 pandemic.

Response:

A. Please see Attachment A for the requested information.

B. FTY and FPFTY assume that all budgeted positions are filled from the time they are authorized. This method of budgeted is utilized as it focuses on the work plan and the work required to complete it. When vacancies occur the Company uses overtime or outside resources to complete the work plan.

C. Please see Attachment B for the requested information.

D. Please see Attachment C for the requested information.

E. Please see Attachment D for the requested information.

F. As described in Attachment D, prior to a vacancy being posted, human resources and the hiring manager will have a discussion regarding the current business needs of the position, and leadership will provide the required approvals to post and fill the position.

G. While COVID-19 has had an impact on Columbia Gas of Pennsylvania's employees and customers, the Company has not experienced changes in vacancies, vacancy rates or changes to labor needs and assumptions. The business needs have not changed and Columbia will continue to staff and perform the work on a consistent basis.

Columbia Gas of Pennsylvania
Employee Headcounts by Employee Category, By Month
Total Gross Labor (Normal, Premium, and Overtime) By Month

I&E Exhibit No. 1
Schedule No. 3
Page 3 of 6

TME 11/30/2018	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
Total Clerical Labor	85	87	86	86	85	86	83	84	82	84	83	152	
Total Exempt Labor	135	136	139	142	143	145	146	146	146	145	145	144	
Total Manual - Non-Union	15	16	15	16	16	16	16	16	16	16	16	16	
Total Manual - Union	422	425	425	423	428	424	422	435	433	431	432	362	
Total Employees	657	664	665	667	672	671	667	681	677	676	676	674	
Total Labor	4,286,871	4,317,506	4,426,706	4,532,382	4,445,565	4,649,921	4,467,197	4,645,672	4,880,962	4,663,738	6,074,223	5,224,200	$56,614,944

TME 11/30/2019	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
Total Clerical Labor	151	150	154	152	82	153	154	160	88	90	90	90	
Total Exempt Labor	143	147	143	144	148	150	155	157	167	164	164	167	
Total Manual - Non-Union	16	16	16	16	15	14	14	15	15	15	13	14	
Total Manual - Union	364	363	371	370	449	397	396	402	479	489	492	492	
Total Employees	674	676	684	682	694	714	719	734	749	758	759	763	
Total Labor	4,816,667	4,996,672	4,517,020	4,656,218	4,949,607	5,143,853	4,909,836	5,578,095	5,516,590	5,459,091	5,859,094	5,600,613	$62,003,357

TME 11/30/2020	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
Total Clerical Labor	90	91	91	94	96	96	95	96	96	96	95	95	
Total Exempt Labor	172	180	179	179	179	178	179	178	178	180	171	174	
Total Manual - Non-Union	14	16	16	16	16	16	16	16	15	15	15	15	
Total Manual - Union	491	494	494	493	493	491	490	486	485	484	483	483	
Total Employees	767	781	780	782	784	781	780	776	774	775	764	767	
Total Labor	5,400,077	6,735,514	6,192,909	6,402,984	4,843,918	4,824,001	4,935,707	6,824,197	5,020,988	5,127,573	5,356,585	5,386,020	$67,050,474

2020/2021	Dec	Jan	Feb	Mar
Total Clerical Labor	94	93	92	93
Total Exempt Labor	173	173	172	168
Total Manual - Non-Union	15	15	15	15
Total Manual - Union	484	478	482	488
Total Employees	766	759	761	764
Total Labor	8,691,722	5,553,079	5,589,699	6,168,769

I&E Exhibit No. 1
Schedule No. 3
Page 4 of 6

I&E-RE-11-D
Attachment B
Page 1 of 1

Date	# of Vacancies
12/31/2017	33
1/31/2018	28
2/28/2018	27
3/31/2018	30
4/30/2018	28
5/31/2018	39
6/30/2018	45
7/31/2018	31
8/31/2018	34
9/30/2018	34
10/31/2018	46
11/30/2018	47
12/31/2018	48
1/31/2019	53
2/28/2019	47
3/31/2019	49
4/30/2019	112
5/31/2019	100
6/30/2019	91
7/31/2019	76
8/31/2019	76
9/30/2019	72
10/31/2019	69
11/30/2019	68
12/31/2019	63
1/31/2020	49
2/29/2020	50
3/31/2020	48
4/30/2020	48
5/31/2020	52
6/30/2020	53
7/31/2020	57
8/31/2020	53
9/30/2020	52
10/31/2020	58
11/30/2020	54
12/31/2020	52
1/31/2021	59
2/28/2021	60
3/31/2021	47

Co	Action	Start Date	Annual Rt
37	REHIRE	9/5/2017	77,000.00
37	HIRE	12/9/2019	53,000.00
37	HIRE	12/9/2019	65,000.00
37	HIRE	12/16/2019	125,000.00
37	HIRE	12/23/2019	59,446.40
37	HIRE	1/2/2020	85,500.00
37	HIRE	1/2/2020	76,000.00
37	HIRE	1/2/2020	85,000.00
37	HIRE	1/2/2020	73,000.00
37	HIRE	1/6/2020	65,977.60
37	HIRE	1/20/2020	57,054.40
37	HIRE	1/20/2020	65,977.60
37	HIRE	1/20/2020	45,760.00
37	HIRE	1/20/2020	73,000.00
37	HIRE	1/20/2020	17,680.00
37	HIRE	1/20/2020	45,760.00
37	HIRE	1/20/2020	45,760.00
37	HIRE	2/3/2020	50,003.20
37	HIRE	2/3/2020	50,000.00
37	HIRE	2/17/2020	59,446.40
37	HIRE	2/17/2020	50,606.40
37	HIRE	2/17/2020	74,650.00
37	HIRE	3/2/2020	80,125.00
37	HIRE	3/16/2020	82,500.00
37	HIRE	3/16/2020	53,414.40
37	HIRE	4/13/2020	64,000.00
37	HIRE	4/13/2020	67,000.00
37	HIRE	5/11/2020	57,012.80
37	HIRE	5/11/2020	72,990.00
37	HIRE	6/1/2020	73,000.00
37	HIRE	7/20/2020	48,257.19
37	HIRE	8/3/2020	90,000.00
37	HIRE	8/31/2020	61,630.40
37	HIRE	9/1/2020	73,000.00
37	HIRE	10/1/2020	73,000.01
37	HIRE	11/2/2020	85,000.01
37	HIRE	11/16/2020	100,000.01
37	HIRE	11/23/2020	55,016.00

Process Step	Step Details	Considerations
Identification of need for new/replacement position	Hiring Manager (HM) works with HRC (HR Consultant) to review business needs of open position for replacement or requirement for additional position. Business case is developed for new/replacement position.	*Business needs, financial considerations, and standards of work weighed.*
Determination of position characteristics	Hiring Manager works with the HRC to determine accurate salary range, job description and job scope level. Information is incorporated as part of business case to be presented to management.	*Hiring Manager and HRC will work together to determine if the position is necessary for the business, how many FTE hours are required and review the job description to ensure all responsibilities and tasks are in line with current business actions.*
Approval for Position	Hiring Manager and HRC present the position business case to upper management for review and approval. Approvals to be obtained from senior management to post and fill vacant position.	*Approvals needed from the following to backfill a position:* *Area Manager, One Level up, State HR Lead, SVP and/or State President.* *If the position is an addition to complement /new position, additional approvals needed from:* *VP of HR and the EC Leader.* *[For financial and budget review, the Manager of Compensation may be consulted.]*
Recruiting Request	After approvals have been obtained, hiring manager will connect with the recruiting partner	
Recruiting Strategy	Hiring manager and Recruiting Partner (RP) work to determine position competencies, experience needed, pre-screening questions, and sourcing strategy	
Job Posting	Job Posting will be developed by the recruiting partner and reviewed by the hiring manager. Posting timeline will be determined relevant to the recruiting strategy. Posts will be initiated and publicized on job boards (internally and externally) for solicitation of candidate applications.	

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-018-D:

Reference Columbia Exhibit No. 4, Schedule 1, p. 2. Provide a detailed breakdown of other employee benefits of $5,906,148 for November 30, 2018, $6,931,682 for November 30, 2019, and $6,712,213 for November 30, 2020.

Response:

Please see I&E-RE-018 Attachment A for the requested information.

Columbia Gas of Pennsylvania, Inc.
Other Employee Benefits

Other Employee Benefits	12 Months Ending November 30, 2018	2019	2020
	$	$	$
9001-Benefit-OH Transfers	1	6	-
9005-Pension-Qualified	-	2,402,125	-
9006-Employee Medical Health Ins	36,647	96,187	26,605
9007-401K Plan	2,784,872	3,058,003	3,493,612
9008-Dental	393,591	425,070	354,273
9009-Group Life - Active	190,963	194,002	278,345
9010-Long Term Disability	381,370	353,401	367,431
9012-Employee Assistance Program	10,222	11,019	12,000
9013-Employee Benefits	-	-	(1,753)
9014-Post Empl Benefits-FAS112	(87,587)	(67,586)	(42,579)
9015-Vision Plan	74,215	71,615	77,000
9017-Profit Sharing	324,006	385,615	(156,729)
9018-Education Reimbursement	6,326	5,250	1,310
9021-Moving Expense	3,841	8,257	146,766
9022-Medical - Active	4,314,545	5,285,744	6,602,007
9023-HMO	1,413,571	1,268,158	528,576
9026-Flex Spending Health	152,252	151,230	161,785
9031-Pension-Credits	-	(2,402,125)	-
9032-Prescriptions	964,047	1,188,661	1,318,263
9033-Pension-SERP	-	7,597	-
9036-Thrift Restoration - Company	1,800	905	1,425
9061-Transfer-Employ Med Health Ins	(3,782,476)	(4,165,776)	(4,796,613)
9064-Transfer-Pension-Qualified	-	5,805	-
9065-Transfer-401K Plan	(1,276,056)	(1,351,480)	(1,659,510)
Total	**5,906,148**	**6,931,682**	**6,712,213**

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-037:

Referring to Exhibit No. 104, Schedule 1, Page 3, please provide workpapers for each budget adjustment in Column (2).

Response:

The budget adjustments in column 2 of Exhibit 104, Schedule 1 page 3 are mathematical in nature and represent the difference between the budgeted 12 months ended November 30, 2021 and the normalized historic test year for the twelve months ended November 30, 2020.

Attachment A provides explanations for the fluctuations in the budget.

I&E Exhibit No. 1
Schedule No. 5
Page 2 of 10

Exhibit No. 104
Schedule No. 1

Witness: K. K. Miller
Witness: N. M. Paloney

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates
FTY = Future Test Year TME November 30, 2021

Line No.	Cost Element Description	Normalized HTY Twelve Months Ended November 30, 2020 (1) $	Witness Paloney: Budget Adjustments 1/ (2) $	Budgeted Twelve Months Ended November 30, 2021 (4)=(1)+(2) $	DR Reference: OCA	DR Reference: I & E	Explanation
		Exh 4, Sch1, Pg 2		Exh 104, Sch1, Pg 5	OCA	I & E	Explanation
1	Labor	38,012,528	828,472	38,841,000	OCA 1-37		See GAS RR-26.
2	Incentive Compensation	1,900,925	462,075	2,363,000	OCA 1-37	I & E RE 17D	NiSource did not achieve expected NOEPS target by Nov 2020. 2021 is planned at target levels for incentive compensation. Also see GASRR 46.
3	Pension	12,701	(12,701)	-	OCA 1-37		Credit to adjust OPEB expense to zero. See Columbia Statement No. 4 , page 10, for further explanation.
4	Pension Deferral Amortization	844,977	23	845,000	OCA 1-37		Budget fluctuation immaterial.
5	OPEB	-	(1,358,000)	(1,358,000)	OCA 1-37		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
6	Other Employee Benefits	6,712,213	1,368,787	8,081,000	OCA 1-37	I & E RE 19	Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
7	Outside Services	18,736,977	8,937,023	27,674,000	OCA 1-36, 1-37	I & E RE 23 D & 24D	See OCA 1-36 and I & E 24 D.
8	Building Leases	2,501,440	(163,440)	2,338,000	OCA 1-37	I&E-RE-37-D	Building Leases and Other Rents and leases budgeted for 2021 at comparable level to 2020 budgets. 2021 Budgeted Rents and Leases - 2,656 , 2020 Budgeted Rents and Leases 2,857 Variance - (201). See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
9	Other Rent and Leases	473,846	(155,846)	318,000	OCA 1-37	I&E-RE-38-D	
10	Corporate Insurance	7,186,459	522,541	7,709,000	OCA 1-37		The 2021 budget increased from $5,861 in 2020 to $7,709 in 2021. The increases were due to inceases is allocations to CPA due to the sale of Columbia Gas of Massacusetts, as well as increases in premiums for casualty, directors and officers, and cyber categories. See "Corporate Insurance" tab herein for changes in costs and allocations.
11	Injuries and Damages	358,171	(50,171)	308,000	OCA 1-37	I & E 29 D	For book purposes, Injuries and Damages is based upon an accrual and not actual payments, and the budget also relfects a projected accrual amount. . For ratemaking purposes, the HTY accrued is adjusted to a five-year average of Injuries and Damages payments, as adjusted by a GDP Deflator. The pro forma FTY expense is specifically adjusted from the HTY expense by the application of an annual average inflation index. Please see Exhibit 4, Schedule 1, Pg 2 line 11 for the detailed calculations of the rate adjustments.
12	Employee Expenses	1,146,308	511,692	1,658,000	OCA 1-37	I&E-RE-40-D	See GAS RR 46 for an explanation regarding lower than normal employee expenses in 2020. The 2021 budget of $1,658 is comparable to the 2020 budget of $1,642. See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
13	Company Memberships	599,737	(29,737)	570,000	OCA 1-37	I & E 32 D, I & E 33-D	The 2021 Budget of $570 is comparable to the 2020 Budget of $560. See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
14	Utilities and Fuel Used in Company Operations	2,207,819	245,181	2,453,000	OCA 1-37	I&E-RE-49-D	The budget adjustment adjusts the normalized HY to the budgeted level in the FTY, and includes gas used in company operations. Gas used in company operations is removed via a ratemaking adjustment. See Columbia statement No. 4 for further information.
15	Advertising	524,096	283,904	808,000	OCA 1-37		See GAS RR 46 for an explanation regarding transition of costs from Outside Services and Corporate Service to Advertising expenses. The budget of $808k is in line with actual spend from 2020 as identified in GAS RR 46.
16	Fleet & Other Clearing	6,459,757	(11,757)	6,448,000	OCA 1-37		2021 budget is comparable 2020 Budget. 2021 budget is $6,448 , and 2020 budget is $6,671 for a variance of ($223). See "Exhibit NP-1 Tab" from Columbia Statement No. 9, Exhibit 1 for budget information for 2020.
17	Materials & Supplies	6,575,513	(435,513)	6,140,000	OCA 1-37		See GAS RR 46 for an explanation regarding actual costs for materials and supplies exceeding budget in 2020. The budget of $6,140 k is in line with actual spend from 2020 as identified in GAS RR 46.
18	Other O&M	642,041	1,075,959	1,718,000	OCA 1-37		Budget adjustment includes $1.2M for non-recurring consulting fees for NiSource Next. Please see Exhibit 104, Schedule 2, Page 11 for ratemaking adjustment to remove from the FTY.
19	PUC, OCA, OSBA Fees	2,008,792	253,208	2,262,000	OCA 1-37	I & E 36 D	The budget for the Fees herein were based off budget to actual assessment for the HTY and reflect the most up to date invoice factors in the Assessment Notice received by the company in September 2020. The fees fluctuate year to year, please see the "PUC Assessment Factors" tab, and are reported in the Company's Annual report to the PUC. Based on the average fees from 2015 - 2020, a budget of $2.2 million is reasonable. See Attachment A for amounts incuded in the Company's annual report.
20	NCSC	58,867,018	17,229,982	76,097,000	OCA 1-37	I & E RE 43, 44, 45	See NCSC Tab.
21	NCSC OPEB costs Amortization	90,313	(313)	90,000	OCA 1-37		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)

1/ - Budget adjustmnets herein relfect the difference between the budget and the normalized expenses as of November 30, 2020.
Normlialized expenses for 2020 represent several impacts from COVID.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates

ure Test Year TME December 31, 2022

Line No.	Cost Element Description	Normalized FTY Twelve Months Ended November 30, 2021 (1) $	Witness Paloney Budget Adjustments (2) $	Budgeted Twelve Months Ended December 31, 2022 (4)=(1)+(2) $	DR Reference OCA	DR Reference I & E	Explanation
		Exh 104, Sch1, Pg 3		Exh 104, Sch1, Pg 6			
1	Labor	39,345,421	(97,421)	39,248,000	OCA 1-38		See GAS RR-26.
2	Incentive Compensation	2,363,000	82,000	2,445,000	OCA 1-38	I & E RE 17D	Budget adjustment the result of inflation.
3	Pension	-	-	-	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
4	Pension Deferral Amortization	844,977	23	845,000	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
5	OPEB	-	(439,000)	(439,000)	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
6	Other Employee Benefits	8,081,000	327,000	8,408,000	OCA 1-38	I & E RE 19	Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)
7	Outside Services	27,377,979	1,224,021	28,602,000	OCA 1-38	I & E RE 23 D & 24D	Increase is the result of a $1,000,000 in increases in various field operational programs: Cross bores , Field Assembled Risers (Company and Customer owned), righs of way clearing, and GPS Legacy .
8	Building Leases	2,475,855	(122,855)	2,353,000	OCA 1-38	I&E-RE-37-D	Building Leases and Other Rents and leases budgeted for 2022 at comparable level to 2021.
9	Other Rent and Leases	318,000	8,000	326,000	OCA 1-38	I&E-RE-38-D	
10	Corporate Insurance	7,709,000	456,000	8,165,000	OCA 1-38	I & E 26 D	The changes to policy premiums that occur mid and late year in the Normalized FTY are the main drivers of the increase in the Budgeted Twelve Months Ended 12/31/22, with a mid-year inflationary adjustment of 2.05% applied in July, 2022
11	Injuries and Damages	364,045	(64,045)	300,000	OCA 1-38		For book purposes, Injuries and Damages is based upon an accrual and not actual payments, and the budget also relfects a projected accrual amount. . For ratemaking purposes, the HTY accrued is adjusted to a five-year average of Injuries and Damages payments, as adjusted by a GDP Deflator. The pro forma FTY expense is specifically adjusted from the HTY expense by the application of an annual average inflation index, and the FPFTY follows the same process. Please see Exhibit 104, Schedule 1, Pg 2, Line 11 for the detailed calculations of the rate adjustments.
12	Employee Expenses	1,568,977	53,023	1,622,000	OCA 1-38	I&E-RE-40-D	Employee expenses budgeted for 2022 at comparable level to 2021.
13	Company Memberships	526,456	(3,456)	523,000	OCA 1-38	I & E 32 D	Compnay memberships budgeted for 2022 at comparable level to 2021.
14	Utilities and Fuel Used in Company Operations	2,136,905	393,095	2,530,000	OCA 1-38	I&E-RE-49-D	The budget adjustment adjusts the normalized HY to the budgeted level in the FTY, and includes gas used in company operations. Gas used in company operations is removed via a ratemaking adjustment. See Columbia statement No. 4 for further information.
15	Advertising	525,166	284,834	810,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
16	Fleet & Other Clearing	6,448,000	(14,000)	6,434,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
17	Materials & Supplies	6,135,826	23,174	6,159,000	OCA 1-38		Budget held consistent with 2021 budget. See explanation at OCA 1-37.
18	Other O&M	535,400	35,600	571,000	OCA 1-38		Employee expenses budgeted for 2022 at comparable level to 2021, after ratemaking adjustment.
19	PUC, OCA, OSBA Fees	2,262,000	-	2,262,000	OCA 1-38	I&E-RE-36-D	See response in OCA 1-37.
20	NCSC	73,506,538	3,787,462	77,294,000	OCA 1-38	I & E RE 43, 44, 45	See NCSC Tab.
21	NCSC OPEB costs Amortization	90,000	-	90,000	OCA 1-38		Amounts provided to the Company from outside third party consultant to reflect updated benefits costs (Hewitt)

I&E Exhibit No. 1
Schedule No. 5
Page 4 of 10

NCSC Expense	With Ratemaking Adjustments	Without Ratemaking Adjustments	
HTY Per Books	60,507,458	60,507,458	
Ratemaking	(1,640,440)		
Normalized HTY	58,867,018	**15,589,542**	See below.
	17,229,982		
FTY Budget	76,097,000	76,097,000	
Ratemaking	(2,590,462)		
Normalized FTY	73,506,538	**1,197,000**	Changes primarily the result of decrease of $250k in Picarro costs in the FTY, offsent by in increase of $650k to the safety plan in the FPFTY.
	3,787,462		
FPFTY Budget	77,294,000	77,294,000	
Ratemaking	(433,995)		
Normalized FPFTY	76,860,005		
	Need to Explain ^		

HTY to FTY

Primary Drivers for Increase	Increases	
Sale of CMA	11.4	
Severance of Employees	1.9	Please see Exhibit 104, Schedule 2, Page 14, Line 10 for ratemaking adjustment to remove.
Safety Plan	5.1	
NiNext Net Savings	-2.3	See GAS-RR-053
Other	-0.5	
	15.6	

1. Sale of CMA - In 2020, NiSource sold Columbia Gas of Massachusetts. As a result of this sale, there was one less company in which to allocate NCSC costs. See below for the calulcation of the additional costs allocated to Pa as a result of the sale of Columbia Gas of Massachusetts. 2019 represents the last full year expenses were incurred by Columbia Gas of Massachusetts.

Operating Company	2019 Mgmt Allocation	2021 Mgmt Allocation	Change as a result of Sale	2019 Actuals NCSC Costs	2021 Budget NCSC Costs	$$ Impact From 2019 Act.
Columbia Gas of Pennsylvania	13.94%	16.41%	2.47%	461.1	483.9	11.4

2. Employee Severance - As a result of the NiSo next initiative described in GAS RR 53, several NCSC employees were offered and accpeted a Voluntary Severance Package. The portion of the costs allocated to Columbia Gas Of Pennsylvania was $1.9 million. Note, the severance for the NCSC employees is separate from severance recognized in the 2021 and 2022 budget for labor costs for Columbia Gas of Pennsylvania. While this one time cost has been reflect in the Corporate Services expense in 2021, it was removed from the FTY by Company Witness Miller at Exhibit 104, Schedule 2, Pg 14, Line 10.

3. The increase in safety plan expenses relate to the expansion of Columbia's Safety Management (SMS) system as described by Company Witness Kempic in Columbia Statement No. 1. The costs included here represent CPA's portion of this initiative for the following programs.

SMS Expenses

Category	Amount	Description
Staffing	$ 3,028,586	As part of this expansion, additional headcount of approximately 60 individuals will be added to provide enhanced ongoing safety training, quality assurance and quality control training and operator qualification training. These positions are in the process of being posted, and it is the Company's intention to fill them as quickly as possible.
Picarro Leak Detection	$ 611,132	As discussed in Company Witness Anstead's testimony at Columbia Statement No. 14, Columbia intends to employ the Picarro platform system in 2021 to enhance its process for leak detection and to refine the prioritization of repairs and replacements for its natural gas distribution system. In addition to the units discussed at Columbia Statement No. 14, one Picarro unit is being procured at the NiSource level to focus on risk reduction and reduction of methane levels by surveying approximately 2000 miles of pipe in PA.
Isometric Drawing for Measurement and Regualtion Station	$ 654,785	The company will create isometric drawings for 241 existing M&R Stations in PA with inlet pressures greater than 125psi and outlet pressures less than 99psi. These stations represent the second highest risk to customers, in the event of an Overpressure, with loow pressure stations being the highest risk. The company is current in the process of addressing low pressure concerns.
PHMSA Compliance Requirements: Traceablke, Verifiable and Complete (TVC) Record Validation	$ 829,394	In order to comply with the Pipeline and Hazardous Materials Safety Administration (PHMSA) Mega Rule regarding traceable, verifiable and complete (TVC) records, the company is utilizing an engineering contractor to mine pipeline data on 16 Transmission pipeline subsystems and 11 Measurement and Regulations stations in PA. There are only 16 transmission pipeline subsystems in PA. This will complete the required work for all of those assets, to determine if they need to have their MAOP revalidated.
	$ 5,123,897	

CPA

Category	2020 Allocation	2020 Total Premium	2020 CPA Share	2021 Allocation	2021 Total Premium	2021 CPA Share	Variance Allocation Change	Variance Premium Increase
Casualty								
Excess Casualty	11.30%	14,118,716	1,595,415	15.50%	13,358,598	2,070,583	4%	$ 475,167.71
AEGIS	11.30%	12,424,470	1,403,965	15.50%	12,461,491	1,931,531	4%	$ 527,566.03
Affiliated Casualty	11.30%	11,342,337	1,281,684	15.50%	11,769,387	1,824,255	4%	$ 542,570.91
Casualty Fees	11.30%	2,072,536	234,197	15.50%	1,897,430	294,102	4%	$ 59,905.07
Professional	11.30%	144,544	16,333	15.50%	146,813	22,756	4%	$ 6,422.47
Executive Risk								
D&O	11.71%	3,162,162	370,289	13.68%	3,371,577	461,232	2%	$ 90,942.51
Fiduciary	11.71%	546,750	64,024	13.68%	552,571	75,592	2%	$ 11,567.28
Crime	11.71%	128,618	15,061	13.68%	127,436	17,433	2%	$ 2,372.05
Special Crime	11.71%	3,922	459	13.68%	3,541	484	2%	$ 25.15
Executive Risk Fees	11.71%	203,356	23,813	13.68%	203,683	27,864	2%	$ 4,050.86
Cyber								
Cyber	8.37%	1,148,942	96,166	10.12%	1,136,123	114,976	2%	$ 18,809.24
Property								
Property	1.72%	5,401,076	92,953	2.60%	5,141,855	133,637	1%	$ 40,684.28
Property Retained Losses	1.91%	911,465	17,427	2.89%	793,232	22,909	1%	$ 5,481.34
Property Fees	1.72%	831,839	14,316	2.60%	693,581	18,026	1%	$ 3,710.23
Medical Stop Loss								
Medical Stop Loss	5.40%	3,168,445	171,096	5.64%	3,171,000	178,741	0%	$ 7,645.10
Workers Comp								
Workers' Comp	8.10%	675,559	54,720	11.50%	611,607	70,335	3%	$ 15,614.49
Affiliated Work Comp	8.10%	3,238,152	262,290	11.50%	2,856,522	328,500	3%	$ 66,209.68
Workers' Comp Fees	8.10%	223,487	18,102	11.50%	211,042	24,270	3%	$ 6,167.36
ESIS WC	8.10%	150,601	12,199	11.50%	143,884	16,547	3%	$ 4,347.93
ESIS Casualty	11.30%	1,403,123	158,553	15.50%	1,205,863	186,909	4%	$ 28,355.91
ESIS Short Term Disability	11.45%	290,817	33,304	14.21%	273,514	38,875	3%	$ 5,570.91
					Projected Increase In Expense			**$ 1,923,186.51**

PUC/OCA/OSBA Fees		
Year	**Amount**	**% Change**
2015	$2,160,919	
2016	$2,170,560	0.446%
2017	$2,037,807	-6.116%
2018	$2,623,298	28.731%
2019	$2,063,274	-21.348%
2020	$2,008,792	-2.641%
Average	$2,177,442	

Exhibit NP-1

I&E Exhibit No. 1
Schedule No. 5
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Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
6									Budget					
7	CE		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8	Labor		23,873	23,108	22,910	23,693	25,709	25,251	28,309	29,646	31,181	31,534	32,271	36,572
9	Incentive Compensation		293	1,171	1,149	1,249	1,238	1,333	1,584	1,642	1,742	2,150	1,133	2,676
10	Pension		2,119	6,005	6,598	-	3	1,137	-	6	549	-	-	
11	OPEB		715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)	(678)
12	Other Employee Benefits		5,076	6,363	6,509	6,184	6,454	4,584	4,791	5,635	5,975	6,445	6,851	7,302
13	Outside Services		15,636	15,175	13,094	12,123	12,104	22,311	26,079	23,977	25,458	22,634	23,453	22,167
14	Rent and Leases		1,314	1,374	1,458	1,615	1,887	2,273	4,791	3,607	3,873	3,203	3,296	2,857
15	Corporate Insurance		3,116	3,574	3,413	3,048	3,004	3,087	4,516	3,481	3,705	3,495	3,631	5,861
16	Injuries and Damages		1,209	944	795	630	630	500	500	400	-	400	400	400
17	Employee Expenses		1,109	1,046	1,163	1,142	1,295	1,305	1,640	1,452	1,501	1,584	1,483	1,642
18	Company Memberships		347	345	249	292	262	256	256	332	491	491	563	560
19	Utilities and Fuel Used in Company Operations		675	570	567	503	1,167	1,303	1,310	1,370	1,102	1,709	1,715	2,142
20	Advertising		500	185	170	170	470	170	170	170	170	170	174	174
21	Fleet		4,663	4,104	4,421	5,046	5,452	5,708	5,728	5,797	5,879	6,255	5,673	6,671
22	Materials & Supplies		4,929	4,767	4,775	4,899	4,649	5,024	5,067	5,962	5,366	5,865	5,568	5,755
23	Other O&M		(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381	193
24	PUC, OCA, OSBA Fees		1,673	1,953	1,354	1,454	1,699	1,583	2,161	2,330	2,460	2,262	2,341	2,262
25	NCSC Shared Services & NGD Shared Operations		31,889	38,399	37,740	39,742	44,597	47,962	49,533	57,719	67,158	66,049	64,185	59,051
26	Amortization		82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		95,231	106,443	106,498	99,407	108,941	121,516	134,890	143,604	157,656	154,193	154,233	156,541

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	A	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1														
2														
3														
4														
5														
6								Actuals						
7	CE		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8	Labor		23,153	23,577	22,845	23,996	25,124	25,818	27,980	29,093	30,019	32,461	36,471	36,293
9	Incentive Compensation		1,303	1,628	1,649	1,690	1,845	1,816	1,791	1,981	2,590	1,381	1,246	2,137
10	Pension		392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12	13
11	OPEB		1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)	(693)
12	Other Employee Benefits		4,995	7,472	6,210	5,880	5,635	5,432	5,992	5,924	6,099	6,015	6,931	9,181
13	Outside Services		15,180	15,440	13,244	12,133	14,113	22,070	22,951	25,361	28,246	21,352	22,850	15,615
14	Rent and Leases		1,306	1,207	1,348	1,485	1,699	1,699	2,252	2,831	3,453	3,234	3,409	2,592
15	Corporate Insurance		3,045	3,241	2,926	2,763	2,734	2,796	2,899	3,024	3,176	3,239	4,363	6,281
16	Injuries and Damages		605	545	340	241	305	(185)	381	363	337	270	512	317
17	Employee Expenses		1,405	1,450	1,553	1,465	1,376	1,264	1,415	1,381	1,545	1,383	1,713	1,063
18	Company Memberships		295	250	293	262	249	313	479	563	599	527	569	854
19	Utilities and Fuel Used in Company Operations		451	417	487	1,094	1,247	1,244	1,287	1,460	1,679	1,693	1,723	1,871
20	Advertising		389	281	167	133	243	236	207	226	283	146	224	719
21	Fleet		4,650	4,726	5,092	5,357	5,780	6,106	5,956	6,206	6,320	6,338	6,906	6,389
22	Materials & Supplies		4,741	4,967	4,412	4,353	5,171	5,343	5,873	5,461	6,327	5,627	6,320	6,643
23	Other O&M		(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242	982
24	PUC, OCA, OSBA Fees		1,721	1,539	1,348	1,523	1,585	1,815	2,161	1,960	1,846	1,814	2,113	2,125
25	NCSC Shared Services & NGD Shared Operations		34,023	36,457	38,899	40,164	43,374	50,760	53,169	56,264	68,727	63,166	64,147	62,366
26	Amortization		82	0	(489)	(1,446)	(594)	185	267	396	511	845	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		95,892	106,766	113,356	101,209	111,952	127,057	134,044	142,299	170,532	141,304	161,271	155,683
29														
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Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	A	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN
6								Variance						
7	CE		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8	Labor		(720)	469	(65)	303	(585)	567	(329)	(553)	(1,162)	927	4,200	(279)
9	Incentive Compensation		1,010	457	500	441	607	484	207	339	848	(769)	113	(539)
10	Pension		(1,727)	(206)	6,490	91	2,486	(6)	14	15	7,989	(8,417)	12	13
11	OPEB		968	(290)	(705)	242	(170)	(748)	42	227	104	266	405	(15)
12	Other Employee Benefits		(81)	1,109	(299)	(304)	(819)	848	1,201	289	124	(429)	80	1,879
13	Outside Services		(456)	265	150	10	2,009	(241)	(3,128)	1,384	2,788	(1,282)	(603)	(6,552)
14	Rent and Leases		(8)	(167)	(110)	(130)	(188)	(574)	(2,539)	(776)	(420)	31	113	(266)
15	Corporate Insurance		(71)	(333)	(487)	(285)	(270)	(291)	(1,617)	(457)	(529)	(255)	732	420
16	Injuries and Damages		(604)	(399)	(455)	(389)	(325)	(685)	(119)	(37)	337	(130)	112	(83)
17	Employee Expenses		296	404	390	323	81	(41)	(225)	(71)	44	(202)	230	(578)
18	Company Memberships		(52)	(95)	44	(30)	(13)	57	223	231	108	35	6	294
19	Utilities and Fuel Used in Company Operations		(224)	(153)	(80)	591	80	(59)	(23)	90	577	(16)	8	(272)
20	Advertising		(111)	96	(3)	(37)	(227)	66	37	56	113	(24)	51	546
21	Fleet		(13)	622	671	311	328	398	228	409	441	83	1,233	(283)
22	Materials & Supplies		(188)	200	(363)	(546)	522	319	806	(501)	961	(238)	752	889
23	Other O&M		460	774	272	720	(29)	2,418	740	(26)	(403)	428	(139)	788
24	PUC, OCA, OSBA Fees		48	(413)	(5)	69	(114)	232	-	(370)	(614)	(448)	(228)	(137)
25	NCSC Shared Services & NGD Shared Operations		2,134	(1,942)	1,159	422	(1,223)	2,798	3,636	(1,455)	1,569	(2,884)	(38)	3,315
26	Amortization		(0)	(74)	(246)	(0)	861	-	-	(100)	-	436	-	0
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operation and Maintenance Expense**		661	324	6,858	1,802	3,011	5,542	(846)	(1,305)	12,876	(12,889)	7,038	(858)

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-038:

Referring to Exhibit No. 104, Schedule 1, Page 4, please provide workpapers for each budget adjustment in Column (2).

Response:

The budget adjustments in column 2 of Exhibit 104, Schedule 1 page 4 are mathematical in nature and represent the difference between the budgeted 12 months ended November 30, 2022 and the normalized future test year for the twelve months ended November 30, 2021. See tab “1-38” in OCA 1-37 Attachment A for explanation of budget changes.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-017-D:

Reference Columbia Exhibit No. 104, Schedule 1, pp. 2-4 concerning incentive compensation. Provide supporting workpapers and detailed calculations used to determine the following claims:

A. $1,900,925 for the 12-months ended November 30, 2020;

B. $2,363,000 for the 12-months ending November 30, 2021;

C. $2,445,000 for the 12-months ending December 31, 2022; and

D. Provide a breakdown for the amounts shown in Parts A, B, and C above by employee category and corresponding capitalization amounts for the 12-months ending November 30, 2020; November 30, 2021; and December 31, 2022.

Response:

A. The normalized Incentive Compensation amount of $1,900,925 is a calculated number that is determined by applying the O&M Percentage (see Exhibit 4 Schedule, 2, Page 5) to the gross amount of Incentive Compensation paid in 2020 for the 2019 Incentive Compensation Plan. Note that this normalized amount for the HTY was determined by inadvertently using a preliminary gross amount paid and not the final amount paid in 2020. The final gross amount of Incentive Compensation paid in 2020 is presented in Table I&E-RE-017-D (B) below totaling $2,888,075. The corrected normalized O&M only amount is $1,566,381. Note, this correction does not impact the normalized amounts in this claim for the FTY or the FPFTY.

The corrected amount of $1,566,381 is the net O&M expense portion of the Incentive Compensation paid during the HTY. Exhibit 4, Schedule 2, Page 4 provides the percentage that was used to determine what portion of Incentive Compensation should be considered O&M Expense for the HTY. Accounting Entries for Incentive Compensation are booked at the Company level. Portions are booked to O&M expense and Capital based upon the Company's experience of Labor being charged to O&M accounts and Capital accounts.

B. This amount was budgeted based upon the salary and incentive potential percentage for each position. Each employee has annual eligible earnings that are defined as base wages plus, for nonexempt employees, overtime wages and shift premiums. The budget estimate is based upon the eligible earnings of each employee multiplied by their incentive value at 100% of target. Budgeting at target represents a normalized expected level of expense for the year. Please see Table I&E-RE-017-D (A) below for recent NiSource Incentive Compensation Payouts as a percentage of Target.

C. See response to B.

Table I&E-RE-017 (A)

NiSource Incentive Compensation Payouts – Percentage of Target						
Employee Group	**2016**	**2017**	**2018**	**2019**	**2020***	**4 Year Average***
Non-Executive	117%	149%	75%	73%	50%	103.5%
Executive	117%	146%	50%	65%	50%	94.5%

*Results for 2020 Plan were abnormal and are not included in the average presented above. Please see the response to OCA-1-022 for details for the 2020 Plan. Also, please see the response to Standard Data Request GAS-RR-027 for incentive plan descriptions.

D. Table I&E-RE-017 (B) below provides a breakdown of the gross (O&M and Capital) amount of incentive compensation paid to Columbia Gas of Pennsylvania employees in the HTY, as discussed in Part A above. The HTY Labor experience O&M percentage calculated on Exhibit 4, Schedule 2, Page 4 and was applied to the gross incentive compensation to arrive at the corrected $1,566,381 net O&M expense. Table I&E-RE-017 (C) below provides the Columbia Gas of Pennsylvania employees' budgeted incentive compensation total gross amounts, and portions allocated to O&M and Capital, for the FTY and FPFTY periods 12-months ending November 30, 2021 and December 31, 2022, respectively.

Table I&E-RE-017 (B)*

Employee Category	Total Gross Paid	% of Total
Exempt	$ 1,530,192	53%
Manual - Non-Union	$ 35,729	1%
Manual - Union	$ 1,148,502	40%
Non-Exempt - Clerical	$ 173,652	6%
Grand Total	$ 2,888,075	100%

*The % of Total allocation for each employee group would be approximately the same in the FTY and the FPFTY.

Table I&E-RE-017 (C)

Employee Category	Total Gross Projection	O&M	Capital
FTY (12-Months Ending 11/30/21)	$ 4,574,000	$ 2,363,000	$ 2,211,000
FPFTY (12-Months Ending 12/31/22)	$ 4,757,000	$ 2,445,000	$ 2,312,000

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-015-D:

Reference Columbia Exhibit No. 4, Schedule 1, p. 2 and Schedule 2, p. 4, concerning incentive compensation:

A. State the number of eligible employees by category (union, non-union, and non-union temporary) for the per book November 30, 2020 incentive compensation amount of $260,629 with a breakdown by employee category along with the base payroll amount used to calculate of incentive compensation;

B. Provide corresponding incentive compensation amounts by the 12-months ended November 30, 2018 and November 30, 2019, and the corresponding total base payroll used as a determination for each period's computed incentive compensation amount; and

C. Provide a breakdown of Ni-Source *allocated* amounts for incentive compensation by the following 12-months ended November 30, 2018, November 30, 2019, and November 30, 2020, the projected amount for November 30, 2021, and the claimed amount for December 31, 2022. Specify where these amounts are included (which line numbers) on Exhibit No. 4, Schedule 1 and Exhibit No. 104, Schedule 1.

Response:

A. Exhibit No. 4, Schedule 1, p. 2 and Schedule 2, p. 4 refers to the per books amount of O&M Incentive Compensation of $260,629 for the twelve months ended November 30, 2020. This is the per books accrual relating to one month (December) of the 2019 Incentive Plan and 11 months (January-November) of the 2020 Incentive Plan. See I&E-RE-015-D Table 1 below for details. It is important to note that Columbia's "per books" amounts are accruals based upon anticipated incentive payouts. Please see the response to I&E-RE-17-D for the actual amount paid in 2020 for the 2019 Plan. While the per books accrual for the 12 Months Ended November 30, 2020 was $260,629, the 2020 Plan was paid-out in early 2021 at the Trigger level, or the gross amount of $2,109,153. All Company employees are eligible to participate in the incentive compensation program. The specific number of eligible employees for the 2019 Incentive Compensation Plan was 785 (492 union/ 293 non-union) with a base payroll of $61,972,410.

B. The corresponding O&M expense per books numbers for the twelve months ended November 30, 2019, the twelve months ended November 30, 2019 and the twelve months ended November 30, 2020, broken out by plan year are:

I&E-RE-015-D Table 1

Incentive Plan Year	TME 11-30-2018		TME 11-30-2019		TME 11-30-2020
2017	$203,806				
2018	$1,317,343		$105,213		
2019			$1,366,966		$260,629
2020					$0
Total	$1,521,149		$1,472,179		$260,629

The payroll amount as of November 30, 2018 was $51,375,435 and as of November 30, 2019 was $59,725,934.

C. Please see I&E-RE-15-D Table 2 below for O&M incentive compensation charges allocated from NiSource Corporate Services Company.

I&E-RE-015-D Table 2

Period	NCSC	Reference
TME 11/30/2018	$2,509,880	Exhibit 4, Schedule 1, Page 2, Line 20, Column 1
TME 11/30/2019	$1,729,947	Exhibit 4, Schedule 1, Page 2, Line 20, Column 2
TME 11/30/2020	$63,025	Exhibit 4, Schedule 1, Page 2, Line 20, Column 3
TME 11/30/2021	$1,981,380	Exhibit 104, Schedule 1, Page 2, Line 20, Column 3

TME 12/30/2022	$2,217,043,	Exhibit 104, Schedule 1, Page 2, Line 20, Column 5

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-048-D:

Reference Columbia Exhibit No. 4, Schedule 1, p. 2 and Schedule 2, p. 14 concerning utilities and fuel used in Company operations:

A. Provide a detailed breakdown by utility type for $2,518,814 in the HTY claim; and

B. Explain how the Company determined the $310,995 reduction for fuel used in Company operations (Exhibit 4, Schedule 2, p. 14), and provide supporting calculations.

Response:

A. Please see Attachment A to this response for the breakdown of per books Utilities and Fuel used in Company Operations of $2,518,814 before rate making adjustments.

B. As discussed in Statement 4, pages 13 and 14, O&M Expense for Gas Used in Company Operations is identified by specific Cost Element designations. An offsetting credit to Gas Cost Expense is also identified using the same Cost Element designation. The actual cost of the gas is recovered through the Gas Cost Recovery Mechanism, therefore ratemaking adjustments to remove both the O&M Expense and the credit to Gas Cost Expense are made to eliminate their impact to base rates. The O&M Expense adjustment is found in Exhibit 4, Schedule 2, p. 14, as referenced by this request, while the adjustment to remove the credit to Gas Cost Expense is made on Exhibit 2, Schedule 3, Page 3, Column 3, Line 16.

Please note that while preparing this response it was discovered that costs accounted for in Cost Element 3851 Gas Left on for Connect, as well as 3813 Gas Used in Company Operations, should have been removed via a rate making adjustment, which would adjust out an additional $58,013 from the HTY for a total HTY adjustment for Gas Used in Company Operations of $369,008. This inadvertent omission also impacts the FTY and the FPFTY. The adjustment on Exhibit 2, Schedule 3, Page 3 is correct as included on line 16.

Please refer to page 1 of Attachment A to this response for the details of the updated HTY ratemaking adjustment of $369,008, and page 2 for updated Rate Making Adjustments for the FTY and the FPFTY.

COLUMBIA GAS OF PENNSYLVANIA, INC
UTILITIES
12 MONTHS ENDING NOVEMBER 30, 2020

Line No.	Cost Element	Description	Amount	Rate Making Adjutsment	Normalized
1	3813	Gas Used in Company Operations 1_/	290,013	(310,995)	(20,982)
2	3849	Service Charges_ Other	17	-	17
3	3851	Gas Left on for Connect 1_/	58,013	(58,013)	-
4	3920	Cable	17,135	-	17,135
5	3921	Electric	245,817	-	245,817
6	3922	Gas	7,236	-	7,236
7	3923	Mobile_Cellular_Pagers	805,216	-	805,216
8	3924	Telephone	1,641	-	1,641
9	3925	Water and Sewage	30,691	-	30,691
10	3926	Telecommunications	1,063,035	-	1,063,035
11	3803	Cash In_Cash Out	-	-	-
12			**2,518,814**	**(369,008)**	**2,149,806**

1_/ Ratemaking adjustments to remove FERC Account 812, Cost Elements 3813 & 3851.

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 11/30/21, FPFTY = Fully Projected Future Test Year TME 12/31/22
Adjustment to Gas Used in Company Operations

Line No.	Description	Reference	Amount (1) $	I&E-RE-048 Correction	
1	HTY Gas Used in Company Operations	Exh. 4, Sch. 2, Pg. 14, Ln. 2	(310,995)	**(369,008)**	
	FTY Adjustment				
2	2021 Average Inflation Index	Exh. 104, Sch. 2, Pg. 19, Ln. 6	1.6400%	**1.6400%**	
3	FTY Incremental Gas Used in Company Operations	Ln 1 x Ln 2	(5,100)	**(6,052)**	
4	FTY Adjustment for Gas Used in Company Operations	Ln 1 + Ln 3	(316,095)	**(375,060)**	**(58,964)**
	FPFTY Adjustment				
5	2022 Average Inflation Index	Exh. 104, Sch. 2, Pg. 19, Ln. 12	1.8500%	**1.8500%**	
6	FPFTY Incremental Gas Used in Company Operations	Ln 4 x Ln 5	(5,848)	**(6,939)**	
7	FPFTY Adjustment for Gas Used in Company Operations	Ln 4 + Ln 6	(321,943)	**(381,998)**	**(60,055)**

I&E Exhibit No. 1
Schedule No. 8
Page 4 of 4

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

OFFICE OF CONSUMER ADVOCATE
Set 1

Question No. OCA 1-025:

Please provide the amount of stock rewards expense included in FPFTY Labor Expense and NCSC Shared Services Expense. The response should include any supporting documentation.

Response:

Columbia Gas of Pennsylvania:	$559,121
NCSC Stock Comp Shared Service Expense Allocated:	$2,217,043

Stock based compensation is a common element of compensation at key management levels of organizations and is a part of NiSource's total compensation package designed to attract and retain executive talent. For the budget reflected above, the Company reviewed 2020 stock reward values, anticipated future reward recipients, estimated target reward values, and 2021 stock reward program design to develop a final budget.

Stock rewards are calculated using the average market price of NiSource's common stock at the date of each grant less the present value of any dividends not received during the vesting period. Stock based compensation is expensed, net of forfeitures, over the vesting period which is generally three years. NiSource Corporate Services' stock based compensation is allocated to the operating companies based on how each employee receiving the stock award charges his/her labor. Please see Standard Data Request GAS-RR-027, Attachment F for further information.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-016-D:

Reference Columbia Exhibit No. 104, Schedule 1, pp. 2-4 concerning incentive compensation. Provide the following:

A. The FTY and FPFTY number of eligible employees by category (union, non-union, and non-union temporary) for incentive compensation;

B. A list of all financial triggers and their specified minimum performance standard to be achieved in order for any incentive amounts to become payable under the incentive plans;

C. State whether financial goals and other triggers must be met before any incentive compensation is paid; and

D. Identify the portion of FPFTY incentive compensation expensed/capitalized that would be paid independent of meeting financial goals.

Response:

A.

FTY: Union – 507; non-union 304
FPFTY: Union – 507; non-union 304
Columbia does not have temporary employees.

B.

The specified minimum performance standard to be achieved in order for any incentive amounts to become payable under the incentive plan(s) is referred to as "trigger" in the Company's incentive plan documents included as Attachments B-E in GAS-RR-027.

C.

Triggers must be met before any incentive compensation is funded related to that measure in the incentive plan. See Company's incentive plan documents included as attachments B-E in GAS-RR-027

D.

Thirty percent of FPFTY incentive compensation would be expensed/capitalized independent of meeting financial goals.

I&E Statement No. 1-R
Witness: John Zalesky

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Rebuttal Testimony

of

John Zalesky

Bureau of Investigation & Enforcement

Concerning:

COVID-19 Emergency Relief Program

LIURP Health and Safety Pilot Program

TABLE OF CONTENTS

<u>INTRODUCTION OF WITNESS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Zalesky. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME JOHN ZALESKY WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 1 AND THE SCHEDULES IN I&E EXHIBIT NO. 1?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the COVID-19 Emergency Relief Program (ERP) for Columbia Gas of Pennsylvania, Inc. (Columbia or Company) as discussed by Office of Consumer Advocate (OCA) witness Roger D.

Colton.[1] Additionally, I will address The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA) witness Harry S. Geller's recommendation for the Company to modify its Low Income Usage Reduction Program (LIURP) Health and Safety Pilot.[2]

COVID-19 ERP

Q. SUMMARIZE MR. COLTON'S TESTIMONY REGARDING A PROPOSED COVID-19 ERP FOR COLUMBIA.

A. In response to the COVID-19 pandemic, Mr. Colton recommends that Columbia continue to pursue implementation of its originally proposed Reduced Income Grant Program (RIGP)[3] as an ERP with some modifications within this rate proceeding.[4] He notes that the petition was denied by the Commission during its July 16, 2020 Public Meeting because it would have redirected funds away from the existing Hardship Fund and because Columbia had not established the need for the additional program.[5] He further notes that this rate proceeding provides an opportunity for the Company to build on the needs identified in its original petition.[6]

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1 OCA Statement No. 4.
2 CAUSE-PA Statement No. 1.
3 Docket No. P-2020-3019578.
4 OCA Statement No. 4, p. 4 and pp. 18-24.
5 OCA Statement No. 4, pp. 19-20.
6 OCA Statement No. 4, p. 22, lines 14-16.

Q. WHAT IS THE BASIS FOR MR COLTON'S RECOMMENDATION FOR THE COMPANY TO PURSUE AN ERP?

A. Mr. Colton largely cites to Phase 3.1 of the United States Census Bureau's Household Pulse Survey[7] to explain the impacts of COVID-19 in Pennsylvania.[8] The data he refers to encompasses the period after April 14, 2021, and generally compares experienced vs. expected loss of employment income and the ability to pay household expenses among various income ranges. Ultimately, the conclusion of Mr. Colton's analysis is that unfortunately, yet not surprisingly, low-income individuals and households have been hit the hardest by the pandemic. They have indeed had greater challenges in maintaining employment and subsequently, being able to pay their household expenses, including utility bills.[9]

Q. DO YOU AGREE WITH MR. COLTON THAT THE COMPANY SHOULD PURSUE A COVID-19 ERP?

A. No. I recommend that the proposed ERP Plan be disallowed. While I am empathetic to the hardships many ratepayers are experiencing as a result of the pandemic, there are several reasons why I do not believe Columbia should be granted a COVID-19 ERP in this proceeding. First, more and more Pennsylvanians are becoming vaccinated and the economy is reopening as evidenced by Governor Wolf's easing of restrictions with the goal of boosting the

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[7] https://www.census.gov/programs-surveys/household-pulse-survey/data.html#phase1 (Accessed June 22, 2021).
[8] OCA Statement No. 4, p. 5, lines 22-25.
[9] OCA Statement No. 4, p. 5, ln. 20 through p. 18, ln. 1.

economy which took effect on May 31, 2021.[10] Although Pennsylvania's current preliminary unemployment rate of 6.9% as of May 2021 is notably higher than the pre-pandemic level of around 4.6%, it is now well below the 16.2% unemployment rate at the height of the pandemic in April 2020.[11] Additionally, on May 14, 2021, the Pennsylvania Department of Labor & Industry announced the Extended Benefits program was coming to an end due to the declining unemployment rate.[12] Further, there has been speculation that workers have not been returning to their previous jobs or accepting available jobs, driving an effort to restore the "work-search" rule for anyone attempting to apply for unemployment benefits within the Commonwealth.[13] Accordingly, Pennsylvania will resume the "work-search" rule in July.[14]

Second, in a motion in response to the lifting of the utility service termination moratorium, Chairman Brown Dutrieuille issued a statement[15] detailing modifications to existing arrearage collection policies to be applied to all utilities for both residential and small business customers. These modifications offer flexible, generous, and reasonable repayment options for ratepayers which most significantly includes extended minimum repayment terms. In the Chairman's belief that it is time to return to the regular collections process, she

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10 https://www.media.pa.gov/pages/health-details.aspx?newsid=1437 (Accessed June 22, 2021).
11 https://data.bls.gov/timeseries/LASST420000000000003 (Accessed June 22, 2021).
12 https://www.media.pa.gov/Pages/Labor-and-Industry-Details.aspx?newsid=575 (Accessed June 23, 2021).
13 https://www.pennlive.com/news/2021/05/pa-gop-wants-to-restore-work-search-rule-for-anyone-applying-for-jobless-benefits html (Accessed June 23, 2021).
14 https://www.media.pa.gov/pages/labor-and-industry-details.aspx?newsid=582 (Accessed June 23, 2021).
15 Motion of Chairman Gladys Brown Dutrieuille, Docket No. M-2020-3019244, on March 11, 2021.

alludes to decreasing COVID-19 cases, deployment of vaccinations, improving employment statistics, and federal government aid including various stimulus payments as well as extended and enhanced unemployment benefits. Subsequently, the Chairman's motion received unanimous support by the remaining three Commissioners. Additionally, Commissioner Coleman provided a statement[16] in which he specifically affirmed his support of the Chairman's motion.

Finally, and perhaps most importantly, in its base rate case filing, the Company did not propose an ERP. Although I do not speak for Columbia and it has an opportunity to respond to Mr. Colton's proposal in its own rebuttal testimony, I believe that Columbia's decision to not request a COVID-19 relief plan for its customers in this rate proceeding is significant because it indicates that what the Company is already doing is sufficient.

Q. IF THE COMMISSION DECIDES TO APPROVE A COVID-19 ERP, WHAT RECOMMENDATIONS WOULD YOU MAKE?

A. If the Commission decides to approve a COVID-19 ERP for Columbia within the context of this base rate proceeding, I recommend the following:

- The Commission carefully consider and establish an appropriate total dollar limit used to fund the ERP such as $400,000.[17]

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[16] Statement of Commissioner John F. Coleman, Jr., Docket No. M-2020-3019244, on March 11, 2021.

[17] OCA Statement No. 4, p. 23.

- The Commission determine and express a clear end date or termination date for the ERP such as June 30, 2022.[18]
- The ERP be fully funded by shareholders as opposed to the Company's ratepayers. The financial burden of this program should not be placed on ratepayers who have been and intend to continue paying their gas bills in-full and on-time. In the event it is decided that shareholders are responsible for funding the ERP, the previous two recommendations are effectively irrelevant.

<u>LIURP HEALTH AND SAFETY PILOT PROGRAM</u>

Q. SUMMARIZE MR. GELLER'S TESTIMONY REGARDING COLUMBIA'S LIURP HEALTH AND SAFETY PILOT PROGRAM.

A. As approved in the Company's Universal Service and Energy Conservation Plan (USECP),[19] the LIURP Health and Safety Pilot Program (pilot program) currently has a budget of $200,000 and is approved to run until the end of 2022. Mr. Geller recommends that Columbia extend the timeframe for an additional term and increase the budget by $600,000.[20] He also recommends that Columbia submit both an interim and final report on the pilot outcomes.[21]

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18 OCA Statement No. 4, pp. 4 and 22-23.

19 Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2019-2021, Order, Docket No. M-2018-2645401, P-2019-3007876, at 27-28 (Order Entered Aug. 8, 2019).

20 CAUSE-PA Statement No. 1, pp. 24 and 35.

21 CAUSE-PA Statement No. 1, pp. 27 and 35.

Q. WHAT IS THE BASIS FOR MR GELLER'S RECOMMENDATION FOR THE COMPANY TO INCREASE THE BUDGET FOR AND EXTEND THE LIURP HEALTH AND SAFETY PILOT PROGRAM?

A. Mr. Geller heavily cites Columbia's USECP case in formulating his basis.[22] The LIURP Health and Safety Pilot Program is directed toward Customer Assistance Program (CAP) customers who would otherwise be eligible for LIURP if not for health and safety issues, such as knob and tube wiring or the presence of moisture, mold, or mildew. He asserts that expanding and extending the pilot program would have a reciprocal impact on CAP costs because it would help mitigate high usage.

Q. DO YOU AGREE WITH MR. GELLER THAT THE COMPANY SHOULD INCREASE THE BUDGET FOR AND EXTEND THE PILOT PROGRAM?

A. No. While Mr. Geller's recommendation is well-intentioned, it is inappropriate to consider implementing these changes in a base rate proceeding. The pilot program was approved in the Company's last USECP proceeding in conjunction with numerous other related programs. It would be inappropriate to extend and expand one of these programs without consideration to all of the other related programs. Additionally, funding for the pilot should not be altered until the pilot program's effectiveness can be properly evaluated.

22 CAUSE-PA Statement No. 1, pp. 24-27.

Further, the pilot program is only approximately halfway complete, running from January 2020 through December 2022, with a significant portion being affected by the COVID-19 pandemic. It is premature at best to request changes to the pilot program well before it is complete and considering only an abbreviated time period that is significantly affected by the pandemic.

Finally, it is important to note the time periods. The pilot program as previously approved runs through December 2022 which coincides with the fully projected future test year (FPFTY) ending date of December 31, 2022 in this base rate filing. Mr. Geller's recommendation to extend the pilot for an additional term would necessarily begin after the FPFTY. Furthermore, as mentioned above, the pilot program originated from the Company's USECP proceeding, and any proposals for change to the pilot may be appropriately raised in the Company's next USECP proceeding.

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR ARGUMENT?

A. Yes. Most recently in the PECO Energy Company – Gas Division proceeding the Commission did not consider CAUSE-PA's proposals relating to CAP and other universal service program issues within the context of the base rate proceeding because they would be more properly considered in its USECP proceeding.[23] The

[23] *PA. PUC V. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, pp. 195-196 (Order Entered June 22, 2021).

Commission referenced last year's Columbia Gas proceeding[24] in which it concluded, "that energy burdens should not be considered separately from other parts of the company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs."[25] It should be noted that in last year's Columbia Gas proceeding the Commission rejected a similar proposal related to the Health and Safety Pilot Program from CAUSE-PA.[26] In that proceeding the Commission agreed with the Administrative Law Judge's recommended decision denying any change to the pilot program until its effectiveness can be evaluated.[27] That evaluation has not occurred given that, as stated above, the pilot program is only halfway compete.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[24] *PA. PUC V. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order Entered February 19, 2021).

[25] *PA. PUC V. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, p. 195 (Order Entered June 22, 2021).

[26] *PA. PUC V. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, pp. 160-161 and 173-174 (Order Entered February 19, 2021).

[27] *PA. PUC V. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, p. 174 (Order Entered February 19, 2021).

I&E Statement No. 1-SR
Witness: John Zalesky

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Surrebuttal Testimony

of

John Zalesky

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

TAXES

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Zalesky. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission or PUC) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME JOHN ZALESKY WHO SUBMITTED TESTIMONY IN I&E STATEMENT NO. 1 AND I&E EXHIBIT NO. 1?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Columbia Gas of Pennsylvania, Inc. (Columbia or Company) witnesses Kelley K. Miller,[1] Nicole M. Paloney,[2] Jennifer Harding,[3] Deborah A. Davis,[4] and Kimberly K. Cartella.[5]

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[1] Columbia Statement No. 4-R.
[2] Columbia Statement No. 9-R.
[3] Columbia Statement No. 10-R.
[4] Columbia Statement No. 13-R.
[5] Columbia Statement No. 15-R.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. No. However, I refer to my direct testimony, its accompanying exhibit, and my rebuttal testimony.[6]

Q. HAS COLUMBIA UPDATED ITS REVENUE INCREASE REQUEST?

A. Yes. The Company revised its revenue request from $98,278,240 to $96,234,266[7] due to changes to the actual cost of long-term debt, the uncollectible account expense rate, updates and corrections to operation and maintenance expenses, updated service revenue, and updated amortization expense.

Q. HAS THE COMPANY ACCEPTED ANY OF YOUR RECOMMENDED ADJUSTMENTS FROM DIRECT TESTIMONY?

A. Yes. Company witness Kelley Miller has accepted the fully projected future test year (FPFTY) portion of my recommended adjustments for utilities and fuel used in company operations and explained how I included an adjustment for the future test year (FTY) portion in error.[8]

Additionally, she accepted my recommendation to end incremental deferrals of COVID-19 uncollectible accounts expense as of the effective date of new rates at the conclusion of this base rate proceeding.[9]

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[6] I&E Statement No. 1, I&E Exhibit No. 1, and I&E Statement No. 1-R.
[7] Columbia Statement No. 4-R, pp. 2-4.
[8] Columbia Statement No. 4-R, p. 3 and pp. 5-6.
[9] Columbia Statement No. 4-R, pp. 6-7.

Q. ARE YOU WITHDRAWING ANY OF YOUR RECOMMENDATIONS FROM DIRECT TESTIMONY?

A. Yes. I am withdrawing my recommendation for NCSC incentive compensation due to being persuaded by witness Paloney's argument that the Company's claim is reasonable in relation to historical payouts as opposed to my recommendation that was based on accrued incentive compensation expense.[10]

Q. PLEASE SUMMARIZE YOUR UPDATED RECOMMENDED ADJUSTMENTS.

A. A summary of my updated recommended adjustments is shown below:

	Updated Company Claim	**Updated I&E Recommended Allowance**	**Updated I&E Adjustment**
Rate Case Expense	$1,060,000	$636,000	($424,000)
Labor Expense	$39,678,280	$39,095,208	($583,072)
Other Employee Benefits	$8,408,000	$7,189,609	($1,218,391)
Incentive Compensation	$2,445,000	$1,892,403	($552,597)
FICA Taxes	$3,001,579	$2,920,654	($80,925)
PUC, OCA, OSBA Fees	$2,262,000	$2,008,792	($253,208)
Stock Rewards Expense	$2,776,164	$0	($2,776,164)
Total O&M Expense & Tax Adjustments			**($5,888,357)**

10 Columbia Statement No. 9-R, p. 23 and pp. 25-26.

SUMMARY OF OVERALL I&E UPDATED POSITION

Q. WHAT IS I&E'S TOTAL UPDATED RECOMMENDED REVENUE REQUIREMENT?

A. I&E's updated total recommended revenue requirement for the Company is $716,512,879. This recommended revenue requirement represents an increase of $55,246,521 to the proforma present rate revenues of $661,266,358. This total recommended allowable increase incorporates my adjustments made in this testimony and those made in the testimony of I&E witness Christopher Keller.[11]

A calculation of the I&E recommended revenue requirement is shown below:

Columbia Gas of PA Inc		TABLE I			
R-2021-3024296		INCOME SUMMARY			
	12/31/22	INVESTIGATION & ENFORCEMENT			
	Proforma	[--]			
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	661,266,358	0	661,266,358	55,246,521	716,512,879
Deductions:					
O&M Expenses	385,384,276	-5,554,224	379,830,052	713,525	380,543,577
Depreciation	108,179,218	0	108,179,218		108,179,218
Taxes, Other	3,715,938	-334,133	3,381,805	0	3,381,805
Income Taxes:					
Current State	1,411,115	352,713	1,763,828	3,266,526	5,030,354
Current Federal	6,691,093	1,162,485	7,853,578	10,765,959	18,619,537
Deferred Taxes	15,685,797	0	15,685,797		15,685,797
ITC	-243,013	0	-243,013		-243,013
Total Deductions	520,824,424	-4,373,159	516,451,265	14,746,010	531,197,275
Income Available	140,441,934	4,373,159	144,815,093	40,500,511	185,315,604
Measure of Value	2,674,106,845	0	2,674,106,845	0	2,674,106,845
Rate of Return	5.25%		5.42%		6.93%

[11] I&E Statement No. 2-SR.

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR RATE CASE EXPENSE.

A. In direct testimony, I recommended an allowance of $636,000,[12] or a reduction of $424,000 to the Company's claim ($1,060,000 - $636,000). I recommended a 20-month normalization period based on the Company's actual base rate filing history over the most recent four base rate cases.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Kelley Miller responded to my recommendation.[13]

Q. SUMMARIZE MS. MILLER'S RESPONSE.

A. Ms. Miller states that Columbia anticipates needing to file rate cases annually for the foreseeable future. Further, in last year's case the Company proposed a 12-month normalization period and subsequently filed the current rate case within 11 months of last year's rate case. Therefore, she opines that a normalization period of 12 months is appropriate.[14]

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[12] I&E Statement No. 1, pp. 4-8.
[13] Columbia Statement No. 4-R, p. 5.
[14] Columbia Statement No. 4-R, p. 5.

Q. WHAT IS YOUR RESPONSE TO MS. MILLER'S ARGUMENT?

A. Rate case expense is more appropriately calculated based on historic filing frequency and not the anticipated need to file future cases. Recent history indicates that a longer normalization period is warranted for Columbia. Despite the Company filing this rate case 11 months after its previous filing, using the filing frequency of the three most recent rate cases and the current rate case provides a more accurate basis for the normalization period, which is 20 months rather than the Company's claimed 12-month period.

Furthermore, as stated in my direct testimony, there are several recent Commission decisions that support basing rate case expense on historic filing frequency.[15] The most recent case is the 2020 Columbia base rate proceeding where the Commission adopted my recommendation for a normalization period that aligns with historic data rather than the Company's future intentions to file a rate case.[16]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend an allowance of $636,000, or a reduction of $424,000 ($1,060,000 - $636,000) to the Company's claim for rate case expense.

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15 *PA PUC v. Emporium Water Company*, Docket No. R-2014-2402324, p. 50 (Order Entered January 28, 2015). *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017). *PA PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

16 I&E Statement No. 1, pp. 7-8.

LABOR EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR LABOR EXPENSE.

A. I recommended an allowance of $39,095,208 for labor expense, or a reduction of $583,072 ($39,678,280 - $39,095,208) to the Company's claim.[17] My recommendation was based on an employee vacancy adjustment of 14 positions. This adjustment was used to determine an allowance amount that more accurately reflects what will be incurred in the FPFTY.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Nicole Paloney responded to my employee vacancy adjustment recommendation.[18]

Q. SUMMARIZE MS. PALONEY'S RESPONSE.

A. Ms. Paloney noted that my headcount reduction of 14 was based on the originally filed headcount of 798 instead of the updated headcount of 811. Ms. Paloney avers that she can reasonably justify this headcount in the FTY and the FPFTY. Also, she asserts that budgeted labor expense is driven largely by the Field Operations Work Plan that requires work to get done despite vacancies using overtime and contracted labor. Therefore, she asserts that my recommendation

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[17] I&E Statement No. 1, pp. 8-11.
[18] Columbia Statement No. 9-R, pp. 21-22.

should be rejected. Also, Ms. Paloney states that my recommendation fails to account for the ongoing wave of hiring. Finally, she indicates that the Company's headcount has increased to 789, which is more than my recommended headcount.

Q. WHAT IS YOUR RESPONSE TO MS. PALONEY'S ARGUMENT?

A. I acknowledge the updated headcount of 811 and note that the Company has not updated its FPFTY labor claim. Based on the Company's data, and as explained in my direct testimony, a certain level of ongoing vacancies due to normal retirements, resignations, transfers, layoffs, etc., exist on a day-to-day operating basis.[19] It is, therefore, unreasonable to assume that the Company will maintain full staffing in the FPFTY. Further, there will always be search and placement time involved in filling employee vacancies as per the Company's vacancy-filling or hiring procedures.[20]

Q. PLEASE CONTINUE.

A. The Company failed to reflect a reduction in its budgeted amounts due to ongoing vacancies in the labor cost. Further, it has not been clearly demonstrated how the use of contractors or overtime is not already reflected in the Company's claim amounts, since the Company's historic results included vacancies that would have presumably included the corresponding impact to contract labor and overtime as necessary to meet field work requirements. The Company's argument that vacant

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[19] I&E Statement No. 1, pp. 9-10 and I&E Exhibit No. 1, Schedule 3, p. 4.
[20] I&E Statement No. 1, p. 10 and I&E Exhibit No. 1, Schedule 3, p. 6.

positions automatically increase outside contract work by an equal amount of payroll costs that would otherwise be incurred is unsupported.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend an allowance of $39,095,208, or a reduction of $583,072 to the Company's claim ($39,678,280 - $39,095,208) for labor expense. Although I could have updated my vacancy adjustment from my direct testimony to 22 positions based on the updated FPFTY headcount of 811 and the most recent actual head count of 789 (811 – 789 = 22), I have maintained my adjustment from direct testimony in order to moderate the impact of the recent hiring wave. Finally, I must reiterate that although the Company has updated its FPFTY headcount claim, it has not updated its labor expense claim.

<u>OTHER EMPLOYEE BENEFITS</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR OTHER EMPLOYEE BENEFITS.

A. In direct testimony, I recommended an allowance of $7,189,609 for other employee benefits expense, or a reduction of $1,218,391 ($8,408,000 - $7,189,609) to the Company's claim.[21] My recommendation was based on a three-year average historical percentage of other employee benefits to labor multiplied by my labor recommendation.

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[21] I&E Statement No. 1, pp. 11-13.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Nicole Paloney responded to my recommendation.[22]

Q. SUMMARIZE MS. PALONEY'S RESPONSE.

A. Ms. Paloney indicated that the third-party administrator who provided the detail for the other employee benefits claim was Aon Hewitt and she attributes the increases in this claim to increased headcount, payroll increases, and increased healthcare costs.

Q. WHAT IS YOUR RESPONSE TO MS. PALONEY'S ARGUMENT?

A. The Company's FTY and FPFTY claims as a percentage of labor expense are significantly higher than, and out of line with, historical figures as demonstrated by the table below.

	Exhibit 4, Sch. 1, p. 2	Exhibit 4, Sch. 1, p. 2	Exhibit 4, Sch. 1, p. 2	Exhibit 104, Sch. 1, p. 2	Exhibit 104, Sch. 1, p. 2
			HTY	FTY	FPFTY
	2018	2019	2020	2021	2022
Other Employee Benefits (OEB)	$ 5,906,148	$ 6,931,682	$ 6,712,213	$ 8,081,000	$ 8,408,000
Labor	$32,215,808	$36,130,190	$38,012,528	$39,345,421	$39,678,280
Ratio OEB to Labor	18.33%	19.19%	17.66%	20.54%	21.19%

Attributing large increases in other employee benefits to increased headcount and payroll increases proves to be inadequate given the historical ratios that would naturally adjust for these factors.

[22] Columbia Statement No. 9-R, pp. 22-23.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend an allowance of $7,189,609, or a reduction of $1,218,391 ($8,408,000 - $7,189,609) to the Company's claim for other employee benefits.

INCENTIVE COMPENSATION

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INCENTIVE COMPENSATION.

A. In direct testimony, I recommended an allowance of $1,519,903 for incentive compensation, or a reduction of $925,097 ($2,445,000 - $1,519,903) to the Company's claim.[23] My recommendation was based on a three-year historic average of incentive compensation payouts due to the variability in incentive payouts on an annual basis and because there is no guarantee of the highest percentage payout in a given year.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witnesses Nicole Paloney[24] and Kimberly Cartella[25] responded to my recommendation.

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[23] I&E Statement No. 1, pp. 13-15.
[24] Columbia Statement No. 9-R, pp. 23-25.
[25] Columbia Statement No. 15-R, pp. 2-3.

Q. SUMMARIZE MS. PALONEY'S RESPONSE.

A. Ms. Paloney indicated that I mistook accrued incentive compensation expense for incentive compensation payouts in my calculation. Ms. Paloney provided tables for both accrued incentive compensation expense and incentive compensation payouts for the three most recent historical years with a line for the average of the three years. The tables indicate an average of $1,519,903 for accrued incentive compensation expense and $1,892,403 for incentive compensation payouts. Ms. Paloney recommends that my adjustment be rejected due to the mix-up between accrued compensation expense and actual payouts. However, she admits that the FPFTY is higher than the three-year average of payouts as it is budgeted for payment at the target level.

Q. SUMMARIZE MS. CARTELLA'S RESPONSE.

A. Ms. Cartella asserts that my adjustment departs from the principles of a FPFTY claim in seeking an adjustment based on historical results. In her response she states that performance metrics such as customer service, safety, and financial achievements and individual employee contributions and performance are the bases for incentive compensation which is in line with NiSource's total rewards philosophy. Therefore, she opines that my adjustment should be disregarded.

Q. WHAT IS YOUR RESPONSE?

A. Due to my original recommendation being calculated based on accruals and not actual historic payouts as explained by Ms. Paloney, I am updating my recommendation based on an average of actual payouts.

Further, I disagree with Ms. Cartella's assertion that my adjustment departs from the principles of a FPFTY claim. At times there are instances where a FPFTY allowance based on historic results is reasonable and appropriate, and this is one of those instances where certain variables are unknown, such as whether the metrics required to earn the full benefit will be met or whether any benefit will even be earned. Therefore, basing the Company's allowance on historic payouts which can fluctuate from year to year and are not guaranteed, is most appropriate.

Q. WHAT IS YOUR UPDATED RECOMMENDATION?

A. I recommend an updated allowance of $1,892,403 based on historic payouts,[26] or a reduction of $552,597 ($2,445,000 - $1,892,403) to the Company's claim for incentive compensation.

FICA TAXES

Q. SUMMARIZE YOUR RECOMMENDATION FOR FICA TAXES.

A. In direct testimony, I recommended a FICA tax expense allowance of $2,894,111 or a reduction of $107,468 ($3,001,579 - $2,894,111) to the Company's claim. My

[26] Columbia Statement No. 9-R, p. 24.

recommended adjustments to labor expense and incentive compensation necessitated a corresponding reduction to the Company's FICA tax expense.[27]

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. No witness directly responded to my recommendation. However, Company witness Nicole Paloney indirectly responded to my recommendation by rejecting my adjustments to labor expense and incentive compensation which cause the need for my FICA tax expense adjustment.[28]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR FICA TAXES?

A. Yes. I am updating my recommendation for FICA Taxes based on my changes made to labor expense and incentive compensation discussed above.

Q. WHAT IS YOUR UPDATED RECOMMENDATION FOR FICA TAXES?

A. I recommend an updated allowance of $2,920,654, or a reduction of $80,925 ($3,001,579 - $2,920,654) to the Company's claim for FICA taxes.

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[27] I&E Statement No. 1, pp. 17-19.
[28] Columbia Statement No. 9-R, pp. 21-25.

Q. HOW DID YOU COMPUTE YOUR UPDATED RECOMMENDATION FOR FICA TAXES?

A. I multiplied my total updated recommended labor expense and incentive compensation amount of $40,987,611 ($39,095,208 + $1,892,403) by the Company's historic test year FICA experienced rate of 7.1257% to determine my recommendation of $2,920,654 ($40,987,611 x 0.071257) for FICA taxes.

<u>PUC, OCA, OSBA FEES</u>

Q. SUMMARIZE YOUR RECOMMENDATION FOR PUC ASSESSMENTS?

A. In direct testimony, I recommended an allowance of $2,008,792, or a reduction of $253,208 ($2,262,000 - $2,008,792) to the Company's claim.[29] I based my recommendation on the most recent general assessment notice of $2,008,792[30] because it is more prudent to rely on the most up-to-date data for PUC assessments.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Nicole Paloney responded to my recommendation.[31]

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[29] I&E Statement No. 1, pp. 19-20.
[30] Columbia Exhibit 4, Schedule 1, p. 2 and Schedule 2, p. 18.
[31] Columbia Statement No. 9-R, p. 26.

Q. SUMMARIZE MS. PALONEY'S RESPONSE.

A. Ms. Paloney proposes that PUC assessments be updated upon receipt of the most current invoice in September 2021.[32]

Q. WHAT IS YOUR RESPONSE TO MS. PALONEY'S ARGUMENT?

A. Given that my recommendation is based on the most current invoice available, I certainly understand Ms. Paloney's request to use the September 2021 invoice. However, I am concerned about the timing of that invoice as it will not be available to be incorporated in testimony and may not be received by the close of the record in this proceeding. Ms. Paloney cannot propose a tangible dollar-based alternative to my recommendation until the September invoice is issued, which is problematic from a timing perspective given that it will likely not be available until after Surrebuttal Testimony, evidentiary hearings and even Main Briefs have been submitted. Therefore, while I do not disagree with using the most current invoice available, my recommendation is more reasonable and should be accepted by the Commission.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend an allowance of $2,008,792, or a reduction of $253,208 to the Company's claim ($2,262,000 - $2,008,792) for PUC assessments.

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[32] Columbia Statement No. 9-R, p. 26.

STOCK REWARDS EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION FOR STOCK REWARDS EXPENSE.

A. In direct testimony, I recommended disallowance of the Company's stock rewards expense claim of $2,776,164 in its entirety.[33] Stock rewards are specifically based on shareholder-oriented goals, not ratepayer goals. Thus, stock rewards should not be funded by ratepayers.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Kimberly Cartella responded to my recommendation.[34]

Q. SUMMARIZE MS. CARTELLA'S RESPONSE.

A. Ms. Cartella asserts that, "stock rewards are based on achievement of metrics that include safety, customer perception, employee culture, environmental, financial and employee diversity."[35] As a part of the total rewards program, she states, stock rewards help the Company to be a competitive employer and further drive requirements to provide safe, reliable, and cost-effective service. Further, stock rewards allow the Company to attract and retain individuals at executive levels. She further cites a study from Aon Hewitt, the same third-party administrator who

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[33] I&E Statement No. 1, pp. 24-25.
[34] Columbia Statement No. 15-R, pp. 3-8.
[35] Columbia Statement No. 15-R, p. 3.

developed the other employee benefits claim as mentioned above, which indicates that many other companies have long-term incentive plans. She further asserts that attaining and retaining key leaders is important for providing reliable service.

Q. WHAT IS YOUR RESPONSE TO MS. CARTELLA'S ARGUMENT?

A. I disagree with Ms. Cartella. Of the six metrics named as a basis for stock rewards, only safety and possibly environmental may correspond to safe and reliable service. Customer perception, employee culture, financial, and employee diversity are not customer-focused metrics. Financial metrics are directly tied to revenue as approved in base rate cases like this one. Specifically, allowing stock rewards in rates directly contributes to financial success and triggers by increasing revenues from ratepayers while not providing ratepayers with a corresponding benefit to safe and reliable service. Therefore, stock rewards should not be funded by ratepayers. Furthermore, I find it unpersuasive that stock rewards limited to executives directly correlate to safe and reliable service.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend a disallowance of the Company's stock rewards expense claim of $2,776,164, in its entirety.

<u>FEDERAL TAX REFORM ADJUSTMENT TARIFF</u>

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING ESTABLISHING THE PROPOSED FEDERAL TAX REFORM ADJUSTMENT (FTRA) TARIFF.

A. In direct testimony, I recommended that the Company's proposed FTRA rider be disallowed.[36] The Company cannot say with any certainty if/when an increase to the federal corporate income tax rate will take effect. I believe the Commission will provide adequate and timely guidance on a statewide basis to affected regulated utilities if such a change in the tax rate takes effect. Columbia should be required to await such guidance, particularly since any changes to the federal income tax rates are merely speculative at this time.

In the event that the Commission decides to allow the Company to establish the FTRA tariff, I recommended that only the *current* federal income tax expense portion of the change be allowed.

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Jennifer Harding responded to my recommendation.[37]

Q. SUMMARIZE MS. HARDING'S RESPONSE.

A. Ms. Harding disagrees with my position. She asserts that this rider is meant to be

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36 I&E Statement No. 1, pp. 26-28.

37 Columbia Statement No. 10-R, pp. 1-9.

temporary until the Commission provides guidance. She points to the delay between the enactment of the Tax Cuts and Jobs Act (TCJA) and the Commission's directives nearly five months later. She further contends that the FTRA is similar to the State Tax Adjustment Surcharge (STAS) which provides for automatic adjustment of rates for changes in Pennsylvania taxes. Furthermore, the FTRA would be set at zero until such a time when tax rates would increase. Ms. Harding partially agrees with my assertion that only the current portion of federal income tax expense should be allowed in the calculation. She further explains that the excess or deficient deferred income taxes and amortization amounts associated with the change in tax rate would be best handled in the context of a future base-rate proceeding.

Q. WHAT IS YOUR RESPONSE?

A. I continue to recommend that the FTRA be denied. Ms. Harding's arguments for this rider, including a potential wait between the enactment of new federal income tax rates and Commission guidance, similarity to the STAS, and the setting of the tariff at zero until enactment of new federal tax rates, are unpersuasive. In the event that the federal tax rate changes, the Company should wait for statewide guidance from the Commission. This ensures that all utilities will be treated in a consistent manner. Given the relatively recent passage of the Tax Cuts and Jobs Act, the Commission will most likely act quickly in issuing guidance if/when such income tax changes occur in the future. Finally, I do not object to Ms. Harding's suggestion regarding the recalculation of deferred income taxes and the associated amortization in a subsequent base rate proceeding if the Commission were to approve the FTRA.

<u>COVID-19 EMERGENCY RELIEF PROGRAM</u>

Q. PLEASE PROVIDE SOME BACKGROUND REGARDING THE EMERGENCY RELIEF PROGRAM (ERP) REQUEST IN THIS PROCEEDING.

A. In response to the COVID-19 pandemic, and as explained in my rebuttal testimony,[38] OCA witness Colton recommends that Columbia continue to pursue implementation of its originally proposed Reduced Income Grant Program as an ERP[39] within this rate proceeding.[40] He notes that the petition was denied by the Commission during its July 16, 2020 Public Meeting because it would have redirected funds away from the existing Hardship Fund and because Columbia had not established the need for the program,[41] and that this rate proceeding provides an opportunity for the Company to build on the needs identified in its original petition.[42]

Q. SUMMARIZE YOUR RESPONSE IN REBUTTAL TESTIMONY TO THE RECOMMENDATION MADE BY MR. COLTON FOR THE ERP.

A. Due to the increasing number of Pennsylvanians becoming vaccinated, the

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[38] I&E Statement No. 1-R, pp. 2-3.
[39] Docket No. P-2020-3019578.
[40] OCA Statement No. 4, p. 4 and pp. 18-24.
[41] OCA Statement No. 4, pp. 19-20.
[42] OCA Statement No. 4, p. 22.

declining unemployment rate, generous modifications to existing arrearage collection policies as detailed by Chairman Brown Dutrieuille,[43] and the fact that the Company did not propose an ERP, I recommended that the proposed ERP be disallowed.[44]

Q. SUMMARIZE THE REBUTTAL TESTIMONY OF COLUMBIA WITNESS DEBORAH DAVIS REGARDING MR. COLTON'S ERP RECOMMENDATION.

A. Ms. Davis asserts that an additional assistance program is not needed at this time. She states that there are ample resources to help customers such as the Hardship Fund, which has expanded in 2020 for customers financially impacted by the pandemic.[45]

Q. DO YOU AGREE WITH THE RESPONSES PRESENTED BY COMPANY WITNESS DAVIS CONCERNING THE PROPOSED ERP?

A. Yes.

Q. HAS YOUR OPINION CHANGED REGARDING THE IMPLEMENTATION OF AN ERP?

A. No. I concur with the Company's position on this issue, and I continue to

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43 Motion of Chairman Gladys Brown Dutrieuille, Docket No. M-2020-3019244, on March 11, 2021.
44 I&E Statement No. 1-R, pp. 3-6.
45 Columbia Statement No. 13-R, p. 27.

recommend that the proposed ERP be disallowed.

Q. HAS THERE BEEN ANY ADDITIONAL RELEVANT ACTION TAKEN BY THE COMMISSION RECENTLY WITH REGARD TO TEMPORARY POLICY ORDERS RELATED TO THE COVID-19 PANDEMIC?

A. Yes. The Commission issued a new Order related to the *Public Utility Service Termination Moratorium; COVID-19 Cost Tracking and Creation of Regulatory Asset* at Docket No. M-2020-3019244 and M-2020-3019755 (Ordered Entered July 15, 2021) (July 15, 2021 Order).

Q. PLEASE SUMMARIZE THE JULY 15, 2021 ORDER.

A. The July 15, 2021 Order discusses prior Orders related to the prohibition of service terminations, reconnections, the later payment arrangement instructions, the regulatory asset treatment for related expenses, and the tracking of extraordinary, nonrecurring incremental COVID-19 related expenses.[46] Subsequent to these prior Commission Orders, the July 15, 2021 Order explains, the Pennsylvania Legislature and the Governor took actions which caused the effectiveness of the Commission's Orders to extend until September 30, 2021 unless terminated earlier by the Commission.[47]

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46 *Public Utility Service Termination Moratorium; COVID-19 Cost Tracking and Creation of Regulatory Asset*, at Docket Nos. M-2020-3019244 and M-2020-3019775 (Order Entered July 15, 2021), p. 2.

47 *Public Utility Service Termination Moratorium; COVID-19 Cost Tracking and Creation of Regulatory Asset*, at Docket Nos. M-2020-3019244 and M-2020-3019775 (Order Entered July 15, 2021), p. 3.

Q. DOES THE JULY 15, 2021 ORDER SUPPORT YOUR RECOMMENDATION RELATED TO COLUMBIA'S ERP?

A. Yes. The September 30, 2021 date outlined by the Pennsylvania Legislature and the Commission indicates that such an ERP would be inappropriate due to the timing of when new rates go into effect in this proceeding.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Direct Testimony

of

Christopher Keller

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

TABLE OF CONTENTS

<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT BACKGROUND?

A. An outline of my education and employment background is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. (Columbia or Company), and make recommendations regarding the Company's rate of return, including capital structure, cost of long-term debt, cost of short-term debt, the cost of equity, and the overall fair rate of return for the fully projected future test year (FPFTY) ending December 31, 2022.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income and is usually expressed as a percentage of the amount of capital invested over a given period of time.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows: RR = E + D + T + (RB x ROR)

Where:

RR	=	Revenue Requirement
E	=	Operating Expenses
D	=	Depreciation Expense
T	=	Taxes
RB	=	Rate Base
ROR	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia*, 262 U.S. 679, 692-93 (1923), and the *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.

4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component, which has financed rate base, to total capital. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure. Because of this difficulty, a proxy group is used as discussed later in this testimony. Next, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The I&E table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS?

A. Columbia witness Paul R. Moul is the primary witness addressing rate of return (Columbia Statement No. 8). Mr. Moul provided analysis for the claimed capital structures, long-term debt, and cost of common equity for Columbia.

Q. PLEASE SUMMARIZE THE COMPANY'S RATE OF RETURN CLAIM.

A. Mr. Moul recommended the following rate of return for the Company based on its FPFTY ending December 31, 2022 (Columbia Exhibit No. 400, Schedule 1, p. 1):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	41.77%	4.54%	1.90%
Short-Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	10.95%	5.95%
Total	100.00%		7.88%

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION.

A. I recommend the following rate of return for the Company (I&E Exhibit No. 2, Schedule 1):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	41.77%	4.58%	1.91%
Short-Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	9.19%	4.99%
Total	100.00%		6.93%

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits of risk in comparison to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR GAS INDUSTRY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are most like the natural gas distribution company subject in this proceeding. I applied the following criteria to Value Line's Natural Gas Utility company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated gas utility industry;
2. The company's stock must be publicly traded;
3. Investment information for the company must be available from more than one source, which includes Value Line;
4. The company must not be currently involved/targeted in an announced merger or acquisition;
5. The company must have four consecutive years of historic earnings data; and
6. The company must be operating in a state that has a deregulated gas utility market.

Q. WHAT CRITERIA DID MR. MOUL USE IN SELECTING HIS GAS PROXY GROUP COMPANIES?

A. Mr. Moul began with the ten gas utility companies in Value Line's Investment Survey. From there, he eliminated one company, UGI Corp., due to its diversified businesses, which includes six reportable segments. These various business segments include propane, international liquefied petroleum gas segments, natural gas utility, energy services, and gas generation. Beyond his rationale for excluding UGI Corp., Mr. Moul has not provided a list of criteria used to determine the remainder of his "Gas Group" other than that the Gas Group is made up of the companies the Commission's Bureau of Technical Utility Services uses to calculate the cost of equity in its Quarterly Earnings Reports (Columbia Gas Statement No. 8, p. 4, line 12 through p. 5, line 2).

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I included the following seven companies in my proxy group (I&E Exhibit No. 2, Schedule 2):

Atmos Energy Corp.	ATO
Chesapeake Utilities Corp.	CPK
NiSource Inc.	NI
Northwest Natural Holding Co.	NWN
ONE Gas, Inc.	OGS
South Jersey Industries	SJI
Spire Inc.	SR

Q. WHAT PROXY GROUP DID MR. MOUL USE IN HIS ANALYSIS?

A. Mr. Moul utilized the following nine companies in his Gas Group (Columbia Exhibit No. 400, Schedule 3, p. 2):

Atmos Energy Corp.	ATO
Chesapeake Utilities Corp.	CPK
New Jersey Resources Corp.	NJR
NiSource Inc.	NI
Northwest Natural Holding Co.	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Holdings, Inc.	SWX
Spire, Inc.	SR

Q. DO YOU AGREE WITH MR. MOUL'S GAS PROXY GROUP?

A. Not entirely. While Mr. Moul's Gas Group included all seven of the companies in my proxy group, I have excluded two of the companies he uses.

Q. PLEASE LIST THE TWO COMPANIES MR. MOUL HAS INCLUDED THAT YOU DO NOT AND EXPLAIN WHY YOU HAVE EXCLUDED THEM FROM YOUR PROXY GROUP.

A. The two companies Mr. Moul included in his Gas Group that I have excluded from my proxy group are New Jersey Resources Corp. and Southwest Gas Holdings, Inc. as these companies did not meet my first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than fifty percent of revenues come from the regulated gas sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business. Therefore, these companies should be removed from the proxy group.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary funding sources are long-term debt and common equity. A capital structure may also include preferred stock and/or short-term debt.

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claimed capital structure is summarized in the table below (Columbia Statement No. 8, p. 2, line 4 and Columbia Exhibit No. 400, Schedule 1, p. 1):

Type of Capital	Ratio
Long-Term Debt	41.77%
Short-Term Debt	3.89%
Common Equity	54.34%
Total	100.00%

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Moul stated that 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 that new rates are in effect (Columbia Statement No. 8, p. 17, lines 16-18).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2019 capital structures, which is the most recent information available at the time of my analysis. The 2019 range consists of long-term debt ratios ranging from 33.18% to 53.48% and equity ratios ranging from 32.78% to 59.01%, with a five-year average of 40.29% for long-term debt and 47.60% for common equity. Although the Company's short-term debt is below the 2019 range of 4.77% to 19.65%, it is within range for the five-year period 2015-2019 for short-term debt of 0.41% to 26.85% (I&E Exhibit No. 2, Schedule 2).

COST OF LONG-TERM DEBT

Q. WHAT IS THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Company's claimed long-term debt cost rate is 4.54% for the FPFTY (Columbia Statement No. 8, p. 18, lines 7-8).

Q. DID THE COMPANY PROVIDE AN UPDATE TO ITS COST OF LONG-TERM DEBT?

A. Yes. The Company updated its cost of long-term debt to 4.58% to reflect the cost of new promissory notes issued in March 2021 (I&E Exhibit No. 2, Schedule 3). The Company's update to its cost of long-term debt is an increase of 0.04% (4.58% - 4.54%) to its initial claim of 4.54%.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF LONG-TERM DEBT?

A. I recommend using the Company's updated long-term debt cost rate of 4.58%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S UPDATED COST RATE OF LONG-TERM DEBT?

A. The Company's updated cost rate of long-term debt is reasonable, as it is representative of the industry. It falls within my proxy group's implied long-term debt cost range of 3.14% to 5.82%, with an average implied long-term debt cost of 4.91% (I&E Exhibit No. 2, Schedule 4). Therefore, I recommend the Company's updated cost rate of long-term debt be used.

COST OF SHORT-TERM DEBT

Q. WHY IS SHORT-TERM DEBT INCLUDED IN THIS PROCEEDING?

A. Natural gas distribution companies (NGDCs) are able to store gas, which is advantageous because it allows NGDCs to pump gas into storage for future use during the summer months when demand and cost for gas are lower. Current gas storage is typically financed by short-term debt. Since ratemaking principles allow for the stored gas in rate base, the associated short-term debt is allowed in a company's capital structure.

Q. WHAT IS THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. The Company's claimed short-term debt cost rate is 0.85% for the FPFTY (Columbia Statement No. 8, p. 18, lines 11-12).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. Mr. Moul stated that the Company obtains its short-term debt from the NiSource money pool, which has as its source commercial paper (Columbia Statement No. 8, p. 18, lines 12-13). The cost of short-term debt for the Company is comprised of the London Interbank Offered Rate (LIBOR) plus a spread for NiSource commercial paper. For this case, Mr. Moul used Bloomberg's three-month forecasted LIBOR rate from the fourth quarter of 2022 of 0.55% (I&E Exhibit No. 2, Schedule 5), and when the 0.30% margin is added, Mr. Moul's short-term debt cost rate estimate is 0.85%.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF SHORT-TERM DEBT?

A. I recommend using the Company's claimed short-term debt cost rate of 0.85%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED COST RATE OF SHORT-TERM DEBT?

A. Although the Blue Chip Financial Forecast for the three-month average forecasted LIBOR rate from the first quarter of 2021 to the first quarter of 2022 reflects a cost rate of 0.30% (I&E Exhibit No. 2, Schedule 6), Mr. Moul's forecasted LIBOR rate relies on the most recent information available. Therefore, I do not oppose the Company's claimed cost rate.

COST OF COMMON EQUITY

COMMON METHODS

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the classical economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk);

and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt and, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it also directly measures the systematic risk of a company group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of "opportunity cost." This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. The most problematic issue with the CE method is determining what constitutes comparable companies.

Q. WHAT METHOD DO YOU RECOMMEND USING TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR COLUMBIA?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. I also recommend using the results of the CAPM as a comparison to the DCF results. My recommendation is consistent with the methodology historically used by the Commission in base rate proceedings, even as recently as 2017, 2018, 2020, and 2021.[1]

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF AND CAPM IN YOUR ANALYSIS.

A. I have used the DCF as the primary method for several reasons. First, the DCF is appealing to investors as it is based upon the concept that the receipt of dividends in addition to the expected appreciation addresses those factors most relevant to investors. Second, the use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. Third, the use of the utilities' own, or in this case, the proxy group's stock prices and growth rates directly in the calculation also causes the DCF to be industry and company specific. Finally, the DCF method is the superior method for

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[1] *Pa. PUC v. City of DuBois – Bureau of Water*; Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company;* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA;* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.;* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131.

determining the rate of return for the current economic market because it measures the cost of equity directly.

I have included a CAPM analysis as a comparison because the CAPM and the DCF include inputs that allow the results to be specific to the utility industry, although the CAPM is far less responsive to changes in the industry than the DCF. The CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, affect the outcome of each method in different ways. Although I have chosen to use the CAPM as a secondary method, it does have several disadvantages and should not be used as a primary method.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is superior for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM and the RP methods are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[2] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives*, states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications."[3] As a result, I conclude that the CAPM's

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[2] Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory" *The New York Times*, 18 Feb 1992: *nytimes.com* Web. 23 Mar 2016.

[3] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults listed above. Additionally, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

SUMMARY OF THE COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. Moul used the DCF, CAPM, RP, and CE methods in analyzing the Company's cost of equity. He made several adjustments to his results, which include consideration for size, various claimed risk factors, and leverage. Ultimately, Mr. Moul opined that a cost of equity of 10.95% is warranted (Columbia Statement No. 8, p. 5, line 11 through p. 6, line 5 and Columbia Exhibit No. 400, Schedule 1, p. 2).

<u>I&E RECOMMENDATION</u>

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR COLUMBIA?

A. Based upon my analysis, I recommend a cost of common equity of 9.19% (I&E Exhibit No. 2, Schedule 1).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the use of the DCF method. As explained below, I used my CAPM result only to present to the Commission a comparison to my DCF results. My DCF analysis uses a spot dividend yield, a 52-week dividend yield, and earnings growth forecasts.

<u>DISCOUNTED CASH FLOW</u>

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group were available from Value Line, no dividends were adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group (I&E Exhibit No. 2, Schedule 7):

Seven-Company Proxy Group	Dividend Yield
Spot	3.42%
52-week average	3.57%
Average	3.49%

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year projected growth rate estimates from Value Line, Yahoo! Finance, Zacks, and Morningstar.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for the seven-company proxy group ranged from 0.00% to 10.50% with an overall average of 5.70% (I&E Exhibit No. 2, Schedule 8).

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows (I&E Exhibit No. 2, Schedule 9):

$$K = D_1/P_0 + g$$

$$9.19\% = 3.49\% + 5.70\%$$

<u>CAPITAL ASSET PRICING MODEL</u>

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K = Cost of equity

R_f = Risk-free rate of return

R_m = Expected rate of return on the overall stock market

β = Beta measures the systematic risk of an asset

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the market.

Q. HOW DID YOU DETERMINE YOUR BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group of seven gas companies, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.85 (I&E Exhibit No. 2, Schedule 10).

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I used the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I used the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives. Additionally, the Commission has recently recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[4] The forecasted yield on the 10-year Treasury Note, as can be seen in Blue Chip Financial Forecasts, is expected to be between 1.70% and 2.00% from the third quarter of 2021 through the third quarter of 2022, and it is forecasted to be 2.00% from 2022-2026. For my forecasted CAPM analysis, I used 1.90%, which is the average of all the yield forecasts I observed (I&E Exhibit No. 2, Schedule 11).

Q. HOW DID YOU DETERMINE THE RETURN ON THE OVERALL STOCK MARKET IN YOUR FORECASTED CAPM ANALYSIS?

A. To arrive at a representative expected return on the overall stock market, I observed Value Line's 1700 stocks and the S&P 500. Value Line expects its universe of 1700 stocks to have an average yearly return of 7.54% over the next three to five years based on a forecasted dividend yield of 1.80% and a yearly index appreciation of 25%. The S&P 500 index is expected to have an average yearly return of 14.11% over the next five years based upon Barron's forecasted dividend yield of 1.51% and

[4] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99.

Morningstar's average expected increase in the S&P 500 index of 12.60% (I&E Exhibit No. 2, Schedule 12).

Q. WHAT IS THE EXPECTED RETURN ON THE OVERALL STOCK MARKET BASED ON YOUR FORECASTED ANALYSIS?

A. The expected return on the overall market is 10.82% for my forecasted analysis (I&E Exhibit No. 2, Schedule 12).

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS?

A. The result of my analysis is as follows (I&E Exhibit No. 2, Schedule 13):

$$K = R_f + \beta(R_m - R_f)$$

$$9.48\% = 1.90\% + 0.85\ (10.82\% - 1.90\%)$$

<u>CRITIQUE OF MR. MOUL'S PROPOSED COST OF EQUITY</u>

Q. DO YOU AGREE WITH MR. MOUL'S PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. Moul's proposed cost of equity analysis for several reasons. First, I disagree with the weights given to the results of Mr. Moul's CAPM, RP, and CE analyses in his recommendation. Second, I disagree with certain aspects of Mr. Moul's discussion of Columbia's risk. Third, I disagree with his application of the DCF including the forecasted growth rate and leverage adjustment he uses. Finally, I disagree with his inclusion of a size adjustment, his reliance on the 30-year Treasury

Bond for his risk-free rate, and the use of a double-adjusted beta in his CAPM analysis.

<u>WEIGHTS GIVEN TO THE CAPM, RP, AND CE METHODS</u>

Q. DO YOU AGREE WITH MR. MOUL'S RELIANCE ON THE CAPM AND RP MODELS?

A. No. While I am not opposed to providing the Commission the results of the CAPM for a point of comparison to the results of the DCF calculation, I am opposed to giving the CAPM and RP considerable weight. For the reasons discussed above, including my reference to recent Commission orders, it is not appropriate to give the CAPM and RP models similar weight to the DCF as Mr. Moul has done in creating his recommended cost of equity range (Columbia Statement No. 8, p. 5, line 17). As discussed above, the CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a simplified version of the CAPM, it suffers these same flaws.

Q. DO YOU AGREE WITH MR. MOUL'S USE OF THE CE METHOD?

A. No. The companies in Mr. Moul's analysis are not utilities, and therefore, they are too dissimilar to be used in a CE analysis. The companies in Mr. Moul's CE proxy group are simply not comparable to gas utilities in terms of their business risk or financial risk profile. Natural gas distribution companies are monopolies, which are subject to very little competition, if any. Due to this minimal competition, utilities in general have very low business risk and are able to maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. Moul's CE proxy group operate in an unregulated competitive environment with a higher level of business risk, they must maintain lower financial risk profiles by employing a smaller amount of leverage. Furthermore, in his CE analysis, Mr. Moul stated, "I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach" (Columbia Statement No. 8, p. 41, lines 16-18). It is my opinion the arbitrary use of 20% is unjustified as I am unaware of any gas utility company that has been awarded or regularly earns a 20% return.

RISK ANALYSIS

Q. SUMMARIZE MR. MOUL'S CLAIMS REGARDING RISK FACTORS THE COMPANY FACES.

A. Mr. Moul described the Company's claimed risk factors in two different sub-sections. In the first section, labeled "Natural Gas Risk Factors," he described the *qualitative* risk factors. In this section, Mr. Moul discussed the potential for bypass, the Company's construction program, the potential discontinuation of the Company's weather normalization adjustment (WNA) tariff design and/or the refusal of its revenue normalization adjustment (RNA) proposal (Columbia Statement No. 8, p. 6, line 6 through p. 10, line 18). In the second section of his risk analysis, labeled "Fundamental Risk Analysis," he described the *quantitative* risk factors. In this section, Mr. Moul discussed the Company's credit quality, as well as many different financial metrics including size, market ratios, common equity ratio, return on book equity, operating ratios, pre-tax interest coverage, quality of earnings, internally generated funds, and betas (Columbia Statement No. 8, p. 11, line 1 through p. 16, line 13).

Q. WHAT HAS MR. MOUL CLAIMED REGARDING THE POTENTIAL RISK OF BYPASS?

A. Mr. Moul opined that the Company faces a unique situation in Western Pennsylvania where gas utilities have overlapping territories; this creates “gas on gas” competition. He stated that one customer left the Company’s system in Spring 2019 and switched to another local distribution company (LDC) that overlaps the Company’s service territory. He claimed that the six interstate pipelines traversing the Company’s service territory create the potential for bypass among certain large volume customers. Additionally, Mr. Moul claimed that local gas production provides another bypass threat, as well as the consolidation of competing LDCs which form a strong competitor (Columbia Statement No. 8, p. 6, line 19 through p. 7, line 9).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL’S CLAIMED RISK OF BYPASS FOR COLUMBIA?

A. The Western Pennsylvania market is unique in that the overlapping territories create “gas on gas” competition; however, whatever competition exists is limited to a very small number of competitors and only in overlapping territories. Mr. Moul did not provide the number of potential customers affected, nor did he quantify the impact of the one customer that left the Company's system or reveal the size of Columbia's territory that is overlapped by NGDC competitors. Just for a point of context, Columbia witness Chad Notestone identifies a total of 444,020 Columbia Gas customers in developing his customer count allocation factor (Columbia Statement No. 8, Exhibit CEN-2, p. 5). Losing only one customer in 2019 to "gas on gas" competition does not seem to support Mr. Moul's contention that this is a substantive risk factor for the Company. Additionally, to the degree that customers must absorb switching costs to move from one NGDC to another, competition will be discouraged. Because insufficient information has been provided, the risk of bypass in overlapping territories cannot be substantiated. Beyond the claimed risk of bypass resulting from overlapping territories of competitors, Columbia faces no more risk than any of the companies in the proxy group. The cost of equity measured by the proxy group adequately compensates investors for the risk of bypass.

Q. WHAT CLAIM HAS MR. MOUL MADE REGARDING THE COMPANY'S RISK OF EXPOSURE IN REPLACING AGING INFRASTRUCTURE?

A. Mr. Moul claimed that the Company incurs additional risk because required capital expenditures to replace aging infrastructure do not increase the Company's customer base (Columbia Statement No. 8, p. 9, lines 19-21). The Company anticipates total capital expenditures over the next five years will equal 82% of the net utility plant in service at December 31, 2020 (Columbia Statement No. 8, p. 10, lines 3-5).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S RISK CAUSED BY THE REPLACEMENT OF AGING INFRASTRUCTURE?

A. Every gas utility faces the same issues of upgrading or replacing its infrastructure. As costs for replacing infrastructure increase, Columbia, like any other regulated gas utility, has the option to file a base rate case at any time to address revenue inadequacy due to increasing costs, infrastructure replacement, or any other associated issues. Base rate cases allow a utility to recover its costs and provide it with the *opportunity* to earn a reasonable return on capital investments. Additionally, as Mr. Moul states in his testimony, the Commission offers risk reducing mechanisms such as the Distribution System Improvement Charge and the FPFTY to help reduce any regulatory lag in recovery of infrastructure investment or other unforeseen expenditures (Columbia Statement No. 8, p. 8, lines 7-16). It should be noted that these mechanisms were not designed to eliminate the need for periodic base rate case filings.

Q. WHAT RISK HAS MR. MOUL CLAIMED WITH RESPECT TO THE POTENTIAL DISCONTINUATION OF THE WEATHER NORMALIZATION ADJUSTMENT MECHANISM AND REFUSAL OF THE REVENUE NORMALIZATION ADJUSTMENT?

A. Mr. Moul stated that, "All of my Gas Group companies have some form of WNA mechanism, and in some cases, other forms of revenue decoupling. Therefore, the market prices of all companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a normalization mechanism" (Columbia Statement No. 8, p. 7, line 23 through p. 8, line 1). Mr. Moul further stated, "If the Company is unable to obtain the RNA mechanism, its risk will increase above that of the Gas Group that serves as a basis to measure the Company's cost of equity..." (Columbia Statement No. 8, p. 8, lines 3-6).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S INCREASED RISK AS A RESULT OF DISCONTINUING THE WNA MECHANISM?

A. The Commission allows utilities the opportunity to propose alternative ratemaking mechanisms, and Columbia has requested continuation of its WNA, albeit with modification, and proposed an RNA in this proceeding. I am not aware of any reason the WNA mechanism cannot be renewed. The Company currently does not have an RNA mechanism in place; therefore, its refusal will not increase risk to the Company. However, if the Commission approves the Company's RNA proposal, its overall risk will decrease as a result. I&E's position on Columbia's specific requests regarding the WNA and RNA proposals are addressed in the testimony of I&E witness Cline in I&E Statement No. 3. Further, Mr. Moul has not produced evidence demonstrating that the Gas Group companies employ either the WNA mechanism that is already authorized for Columbia, or the RNA mechanism that Columbia has proposed.

Q. WHAT HAS MR. MOUL CLAIMED REGARDING QUANTITATIVE RISK FACTORS IN THE SECTION LABELED "FUNDAMENTAL RISK ANALYSIS?"

A. Mr. Moul states that it is necessary to establish a company's relative risk position within its industry through an analysis of quantitative and qualitative factors. Mr. Moul uses various financial metrics to compare Columbia to the S&P Public Utilities Index and his Gas Group (Columbia Statement No. 8, p. 11, lines 2-11).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S "FUNDAMENTAL RISK ANALYSIS?"

A. One of the points he discusses, size risk, has been discussed and disputed elsewhere in my direct testimony. Throughout the remainder of his "fundamental risk analysis," Mr. Moul made several statements to indicate that the Company has no more of a risk than any other company in his Gas Group. First, regarding operating ratios, Mr. Moul stated, "The five-year average operating ratios were 74.3% for the Company, 84.1% for the Gas Group, and 78.8% for the S&P Public Utilities. The Company's operating ratios were lower than the Gas Group, thereby indicating lower risk." (Columbia Statement No. 8, p. 14, lines 11-13). Second, concerning coverage, he stated, "Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 4.43 times for the Company, 4.23 times for the Gas Group, and 3.22 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk" (Columbia Statement No. 8, p. 14, lines 18-22). Third, concerning internally generated funds, he stated, “Historically, the five-year average percentage of IGF to capital expenditures was 64.5% for the Company, 59.5% for the Gas Group and 74.1% for the S&P Utilities. Had the Company paid dividends in recent years, its IGF would have been weaker. The Company’s average IGF to construction percentage has been slightly stronger than the Gas Group, which can be traced to the lack of dividend payments by the Company” (Columbia Statement No. 8, p. 15, lines 10-15). Finally, concerning betas, he stated, “A comparison of market risk is shown by the Value Line beta of 0.87 as the average for the Gas Group and 0.91 as the average for the S&P Public Utilities. The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities” (Columbia Statement No. 8, p. 16, lines 2-6).

While some measures Mr. Moul discussed may imply a higher risk profile for the Company, he provided other more convincing measures that illustrate the Company has lower risk. Overall, through his own analysis and testimony, Mr. Moul substantiated that the Company has very similar risk as compared to that of his Gas Group.

COST OF EQUITY ADJUSTMENTS

INFLATED GROWTH RATES USED IN DCF ANALYSIS

Q. WHAT GROWTH RATE HAS MR. MOUL USED IN HIS DCF ANALYSIS?

A. Mr. Moul used a growth rate of 7.50% (Columbia Statement No. 8, p. 30, line 15).

Q. WHAT IS THE BASIS FOR MR. MOUL'S GROWTH RATE?

A. Mr. Moul stated, "Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (6.83%), Zacks (9.16%), and Value Line (9.89%)." (Columbia Statement No. 8, p. 25, lines 8-9). Mr. Moul used a growth rate of 7.50% which is below the midpoint of the data set, claiming that his DCF growth rate is supported by continued infrastructure spending (Columbia Statement No. 8, p. 26, lines 8-10).

Q. DO YOU AGREE WITH MR. MOUL'S GROWTH RATE ANALYSIS?

A. No. I disagree with Mr. Moul's outdated growth rate analysis. Mr. Moul used earnings per share growth rates from Yahoo! Finance and Zacks dated January 3, 2021 and Value Line dated November 27, 2020 (Columbia Exhibit No. 400, Schedule 9). My earnings per share growth rates from Yahoo! Finance, Zacks, and Morningstar are based on information dated April 14, 2021 and Value Line dated February 26, 2021, which is more recent than Mr. Moul's growth rate analysis, and therefore should be used instead of Mr. Moul's growth rate analysis.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE RESULTS OF MR. MOUL'S PROJECTED GROWTH RATES?

A. Yes. While the five-year projected growth rates can be used in analyses, one must be aware that analysts' estimates may be biased. This bias has been observed in literature. An article written by Professors Ciciretti, Dwyer, and Hasan in 2009 observed strong support of earnings forecasts being higher than actual earnings.[5] In spring of 2010, McKinsey On Finance presented an article reporting that after a decade of stricter regulation analysts' forecasts are still overly optimistic.[6]

Analysts' estimates are an attempt to forecast future cash flows and thus expected earnings growth. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings. If the base year earnings are abnormally high, the growth rates from which they are calculated will be biased downward. Similarly, if the base year earnings are abnormally low, the growth rates from which they are calculated will be biased upward. As a result, it is typically necessary to employ a methodology to smooth out the abnormally high or low base year earnings.

LEVERAGE ADJUSTMENT APPLIED TO DCF ANALYSIS

Q. HAS MR. MOUL MADE ANY ADDITIONAL ADJUSTMENTS TO THE RESULT OF HIS DCF ANALYSIS?

A. Yes. Mr. Moul proposed a 217-basis point "leverage" adjustment to the results of his DCF analysis to account for applying a market-determined cost of equity to a book value capital structure (Columbia Statement No. 8, p. 30, lines 2-5).

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[5] Ciciretti, Rocco; Dwyer, Gerald R; and Iftekhan Hasan. "Investment Analysts' Forecasts of Earnings" Federal Reserve Bank of St. Louis *Review*, September/October 2009, 91 (5, part 2) pp. 545-67.

[6] Goedhart, Marc J; Raj, Rishi; and Abhishek Saxena. "Equity analyst: Still too bullish" McKinsey On Finance Number 35 Spring 2010, pp. 14-17.

Q. WHAT IS FINANCIAL LEVERAGE?

A. Financial leverage is the use of debt capital to supplement equity capital. A firm with significantly more debt than equity is considered to be highly leveraged.

Q. WHAT IS A MARKET-TO-BOOK (M/B) RATIO?

A. A market-to-book ratio is used to evaluate a public firm's equity value by comparing the market value and book value of a company's equity. One way of doing this is to divide the current price per share of stock by the book value per share. A M/B result of above one (1) is desired.

Q. HAS MR. MOUL PROPOSED TO ADJUST THE RESULT OF HIS DCF ANALYSIS TO RECOGNIZE HOW THE COMPANY IS LEVERAGED?

A. No. Mr. Moul has not proposed to change the capital structure of the utility (a leverage adjustment), nor has he proposed to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul has proposed to make an adjustment to account for applying the market value cost rate of equity to the book value of the utility's equity. I am not aware of any term in academic journals, textbooks, or other literature that describes this type of adjustment.

Q. WHAT IS THE BASIS FOR MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. Mr. Moul stated that in order to make the DCF results relevant to a book value capital structure, the market-derived cost of equity needs to be adjusted to take into consideration the difference in financial risk (Columbia Statement No. 8, p. 27, lines 1-4). Mr. Moul opined this is because market valuations of equity are based on market value capital structures, which in general have more equity, less debt, and therefore, less risk than book value capital structures (Columbia Statement No. 8, p. 26, lines 19-25).

Q. HOW HAS MR. MOUL ATTEMPTED TO JUSTIFY THE LEVERAGE ADJUSTMENT USED IN HIS ANALYSIS?

A. Mr. Moul simply states:

> I know of no means to mathematically solve for the 2.17% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 2.17% adjustment is merely a convenient way to compare the 13.46% return computed using the Modigliani & Miller formulas to the 11.29% return generated by the DCF model based on a market value capital structure.[7]

[7] Columbia Statement No. 8, p. 29, lines 20-25.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 217 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 217 additional basis points to the Company's cost of equity:

Columbia Gas of Pennsylvania, Inc.	
Claimed Equity Percentage of Capital Structure	54.34%
Additional Basis Points to Calculated Cost of Equity	217
Claimed Rate Base*	$2,673,012,065
Total Impact	**$31,519,570**

(0.5434 x 0.0217 x $2,673,012,065)

*(Columbia Exhibit 102, Schedule 3, p. 3)

In this example, an addition of 217 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $31,519,570.

Q. DO YOU AGREE WITH MR. MOUL'S "LEVERAGE ADJUSTMENT" JUSTIFICATION?

A. No. Mr. Moul's adjustment is inappropriate for a couple of reasons, including the characterization of financial risk and Commission precedent.

Q. EXPLAIN HOW RATING AGENCIES ASSESS FINANCIAL RISK.

A. Rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements for their analysis, not market capital structure. The income statement reflects the financial risk of a company because it represents the performance of the company over a certain period of time. A change in the market value of the stock is not reflected in the income statement nor is a change in market value capital structure reflected in the book value capital structure unless treasury stock is purchased. It is a company's financial statements that affect the market value of the stock, and, therefore, the financial statements and the book value capital structure that is relied upon in an analysis such as that done by rating agencies.

Q. HAS THE COMMISSION RECENTLY REJECTED THE USE OF A LEVERAGE ADJUSTMENT?

A. Yes. The following four cases are the most recent instances where the Commission has rejected the use of a "leverage adjustment."

First, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, at Docket No. R-00072711 (Order Entered July 31, 2008), p. 38, the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "[t]he fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases."

Second, in *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, at Docket No. R-2010-2179103 (Order Entered July 14, 2011), p. 79, the Commission agreed with the I&E position and stated, "any adjustment to the results of the market based DCF are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment."

Third, in the most recent case of *Pennsylvania Public Utility Commission, et al v. UGI Utilities, Inc. – Electric Division*, at Docket No. R-2017-2640058 (Order Entered October 25, 2018), pp. 93-94, the Commission agreed with the I&E position and stated, "we conclude that an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et. al v. Columbia Gas of Pennsylvania, Inc.*, at Docket R-2020-3018835 (Order Entered February 19, 2021), pp. 137-141, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excludes the use of a leverage adjustment.

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING THE PROPOSED LEVERAGE ADJUSTMENT.

A. I recommend that Mr. Moul's proposed 217-basis point leverage adjustment be rejected because true financial risk is a function of the amount of interest expense, and capital structure information provided to investors through Value Line is that of book values, not market values. This demonstrates that investors base their decisions on book value debt and equity ratios for the regulated utilities, and therefore, no adjustment is needed. Mr. Moul's proposed adjustments serve only to manipulate the DCF's market-based methodology.

Q. WHAT WOULD MR. MOUL'S DCF BE WITHOUT ANY ADJUSTMENTS?

A. Without Mr. Moul's use of outdated growth rates and a leverage adjustment, his DCF would consist of his calculated dividend yield of 3.79% and my average growth rate of 5.70% as shown above results in a 9.49% cost of equity which is well below Mr. Moul's claimed cost of equity of 10.95% and much closer to my recommended cost of equity of 9.19%.

<u>INFLATED BETAS USED IN CAPM ANALYSIS</u>

Q. HOW HAS MR. MOUL INFLATED THE BETAS EMPLOYED IN HIS CAPM ANALYSIS?

A. Mr. Moul has used the same logic for inflating his CAPM betas from 0.87 to 1.10 that he used to enhance his DCF returns, through a financial risk or "leverage" adjustment (Columbia Statement No. 8, p. 35, line 13 through p. 36, line 9). Such enhancements are unwarranted for beta in a CAPM analysis for the same reasons that enhancements are unwarranted for DCF results.

Also, if the unadjusted *Value Line* betas do not reflect an accurate investment risk as Mr. Moul contends, the question naturally arises as to why *Value Line* does not publish betas that are adjusted for leverage. Until this type of adjustment is demonstrated in the academic literature to be valid, such leverage adjusted betas in a CAPM model should be rejected. Furthermore, the Commission found no basis to add leverage adjusted betas in the recently litigated UGI Electric base rate case.[8]

SIZE ADJUSTMENT APPLIED TO CAPM ANALYSIS

Q. WHAT SIZE ADJUSTMENT HAS MR. MOUL PROPOSED?

A. Mr. Moul added 102 basis points to his CAPM indicated cost of common equity because he opined that as the size of a firm decreases, its risk and required return increases (Columbia Statement No. 8, p. 38, lines 4-5). Mr. Moul relied upon technical literature including Morningstar's Stocks, Bonds, Bills, and Inflation Yearbook, a Fama and French study entitled "The Cross-Section of Expected Stock Returns," and an article published in Public Utilities Fortnightly entitled "Equity and the Small-Stock Effect" (Columbia Statement No. 8, p. 38, lines 5-13).

Q. DO YOU AGREE WITH MR. MOUL'S SIZE ADJUSTMENT?

A. No. Mr. Moul's proposed size adjustment is unnecessary because the technical literature he cited supporting investment adjustments related to the size of a company is not specific to the utility industry; therefore, it has no relevance in this proceeding.

[8] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 100.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE SIZE ADJUSTMENT FOR RISK IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes:

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[9]

Columbia has presented no evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. Absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected. Additionally, and more importantly, the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation.[10]

Q. WHAT WOULD MR. MOUL'S CAPM RESULT BE WITHOUT THE SIZE ADJUSTMENT AND INFLATED BETAS?

A. Mr. Moul's CAPM result would be 9.63% without his size adjustment and inflated betas. The calculation is repeated below without Mr. Moul's adjustments:

Rf	+	ß	*	(Rm-Rf)	+	size	=	K
2.00%	+	0.87	*	8.77%	+	0.00%	=	9.63%

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9 Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

10 *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 100.

OVERALL RATE OF RETURN RECOMMENDATION

Q. WHAT IS THE COMPANY'S PROPOSED OVERALL RATE OF RETURN?

A. The Company's proposed overall rate of return is 7.88% (Columbia Statement No. 8, p. 2, line 4).

Q. WHAT IS I&E'S RECOMMENDED OVERALL RATE OF RETURN?

A. I recommend an overall rate of return for the Company of 6.93% (I&E Exhibit No. 2, Schedule 1).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

PROFESSIONAL AND EDUCATIONAL EXPERIENCE
CHRISTOPHER KELLER

Professional Experience

January 2014 to Present
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
Bureau of Investigation & Enforcement

September 2008 to January 2014
Insurance Company Financial Analyst
Pennsylvania Insurance Department, Harrisburg, Pennsylvania
Bureau of Licensing & Financial Analysis

Education and Training

FAI Utility Finance and Accounting for Financial Professionals, Boston, MA
May 21-23, 2014

York College of Pennsylvania, York, Pennsylvania
Master of Business Administration, Finance Concentration, 2008
Bachelor of Science, Accounting, 2006

Testimony Submitted

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2020-3018929 – PECO Energy Company – Gas Division (ROR) (proceeding ongoing)
- Docket No. P-2020-3020914 – Twin Lakes Utilities, Inc. (529 Proceeding) (proceeding ongoing)
- Docket No. R-2020-3018835 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. R-2020-3019680 – UGI Utilities, Inc. (1307(f))
- Docket No. P-2020-3019356 – PPL Electric Utilities Corporation (DSP)
- Docket No. R-2019-3015162 – UGI Utilities, Inc. – Gas Division (ROR)
- Docket No. R-2019-3010955 – City of Lancaster – Sewer Fund (O&M)
- Docket No. R-2019-3009647 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2018-3006818 – Peoples Natural Gas Company LLC (O&M)
- Docket No. R-2018-3000124 – Duquesne Light Company (O&M)
- Docket No. R-2018-3001631 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2018-3001632 – UGI Penn Natural Gas, Inc. (1307(f))
- Docket No. R-2018-3001633 – UGI Utilities, Inc. (1307(f))
- Docket No. R-2018-2645938 – Philadelphia Gas Works (1307(f))
- Docket No. P-2017-2637855 – Metropolitan Edison Company (DSP)

Testimony Submitted (Continued)

I have testified and/or submitted testimony in the following proceedings:

- Docket No. P-2017-2637857 – Pennsylvania Electric Company (DSP)
- Docket No. P-2017-2637858 – Pennsylvania Power Company (DSP)
- Docket No. P-2017-2637866 – West Penn Power Company (DSP)
- Docket No. R-2017-2602627 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2017-2602638 – UGI Utilities, Inc. (1307(f))
- Docket No. R-2017-2586783 – Philadelphia Gas Works (O&M)
- Docket No. R-2017-2587526 – Philadelphia Gas Works (1307(f))
- Docket No. I-2016-2526085 – Delaware Sewer Company (529 Proceeding)
- Docket No. R-2016-2531550 – Citizens' Electric Company (O&M)
- Docket No. R-2016-2531551 – Wellsboro Electric Company (O&M)
- Docket No. R-2016-2537349 – Metropolitan Edison Company (CWC and CAP)
- Docket No. R-2016-2537352 – Pennsylvania Electric Company (CWC and CAP)
- Docket No. R-2016-2537355 – Pennsylvania Power Company (CWC and CAP)
- Docket No. R-2016-2537359 – West Penn Power Company (CWC and CAP)
- Docket No. R-2016-2543311 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2015-2518438 – UGI Utilities, Inc. – Gas Division (CWC and USP)
- Docket No. P-2015-2511333 – Metropolitan Edison Company (DSP)
- Docket No. P-2015-2511351 – Pennsylvania Electric Company (DSP)
- Docket No. P-2015-2511355 – Pennsylvania Power Company (DSP)
- Docket No. P-2015-2511356 – West Penn Power Company (DSP)
- Docket No. R-2015-2468056 – Columbia Gas of Pennsylvania, Inc. (O&M)
- Docket No. P-2014-2404341 – Delaware Sewer Company (529 Investigation)
- Docket No. R-2014-2452705 – Delaware Sewer Company (O&M)
- Docket No. R-2014-2428304 – Borough of Hanover – Water (O&M)
- Docket No. R-2014-2419774 – Wellsboro Electric Company (Customer Choice Support Charge)
- Docket No. R-2014-2420279 – UGI Central Penn Gas, Inc. (1307(f))

Assisted with the Following Cases

- Docket No. R-2017-2631441 – Reynolds Water Company (ROR)
- Docket No. R-2016-2580030 – UGI Penn Natural Gas, Inc. (ROR)
- Docket No. R-2014-2462723 – United Water Pennsylvania (CWC)
- Docket No. R-2014-2428742 – West Penn Power Company (CWC)
- Docket No. R-2014-2428743 – Pennsylvania Electric Company (CWC)
- Docket No. R-2014-2428744 – Pennsylvania Power Company (CWC)
- Docket No. R-2014-2428745 – Metropolitan Edison Company (CWC)
- Docket No. R-2013-2397353 – Pike County Light & Power Company (Gas) (O&M)
- Docket No. R-2013-2397237 – Pike County Light & Power Company (Electric) (O&M)

I&E Exhibit No. 2
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Exhibit to Accompany

the

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

I&E
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
Columbia Gas of Pennsylvania, Inc.			
Long Term Debt	41.77%	4.58%	1.91%
Short-Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	9.19%	4.99%
Total	100.00%		6.93%

Proxy Group Capital Structure

	2019		2018		2017		2016		2015		Average
Atmos Energy Corp											
Long-term Debt	$ 3,529.452	36.22%	$ 2,493.665	31.81%	$ 3,067.045	41.37%	$ 2,188.779	33.77%	$ 2,455.388	40.20%	36.67%
Short-term Debt	464.915	4.77%	575.780	7.34%	447.745	6.04%	829.811	12.80%	457.927	7.50%	7.69%
Common Equity	5,750.223	59.01%	4,769.950	60.85%	3,898.666	52.59%	3,463.059	53.43%	3,194.797	52.30%	55.64%
	9,744.590	100.00%	7,839.395	100.00%	7,413.456	100.00%	6,481.649	100.00%	6,108.112	100.00%	100.00%
Chesapeake Utilities											
Long-term Debt	450.064	35.75%	316.020	27.99%	197.395	21.12%	136.954	17.27%	149.340	21.93%	24.81%
Short-term Debt	247.371	19.65%	294.458	26.08%	250.969	26.85%	209.871	26.47%	173.397	25.47%	24.90%
Common Equity	561.577	44.60%	518.439	45.92%	486.294	52.03%	446.086	56.26%	358.138	52.60%	50.28%
	1,259.012	100.00%	1,128.917	100.00%	934.658	100.00%	792.911	100.00%	680.875	100.00%	100.00%
Nisource Inc											
Long-term Debt	7,907.800	53.48%	7,105.400	50.92%	7,512.200	57.62%	6,058.200	52.15%	5,948.500	57.42%	54.32%
Short-term Debt	1,773.200	11.99%	1,977.200	14.17%	1,205.700	9.25%	1,488.000	12.81%	567.400	5.48%	10.74%
Common Equity	5,106.700	34.53%	4,870.900	34.91%	4,320.100	33.13%	4,071.200	35.04%	3,843.500	37.10%	34.94%
	14,787.700	100.00%	13,953.500	100.00%	13,038.000	100.00%	11,617.400	100.00%	10,359.400	100.00%	100.00%
Northwest Natural Gas Co											
Long-term Debt	806.796	44.28%	706.247	41.88%	683.184	46.16%	679.334	42.91%	576.700	35.43%	42.13%
Short-term Debt	149.100	8.18%	217.620	12.90%	54.200	3.66%	53.300	3.37%	270.035	16.59%	8.94%
Common Equity	865.999	47.53%	762.634	45.22%	742.776	50.18%	850.497	53.72%	780.972	47.98%	48.93%
	1,821.895	100.00%	1,686.501	100.00%	1,480.160	100.00%	1,583.131	100.00%	1,627.707	100.00%	100.00%
One Gas Inc.											
Long-term Debt	1,314.064	33.18%	1,285.483	35.44%	1,193.257	33.99%	1,192.446	36.97%	1,201.305	39.32%	35.78%
Short-term Debt	516.500	13.04%	299.500	8.26%	357.215	10.18%	145.000	4.50%	12.500	0.41%	7.28%
Common Equity	2,129.390	53.77%	2,042.656	56.31%	1,960.209	55.84%	1,888.280	58.54%	1,841.555	60.27%	56.95%
	3,959.954	100.00%	3,627.639	100.00%	3,510.681	100.00%	3,225.726	100.00%	3,055.360	100.00%	100.00%
South Jersey Industries Inc											
Long-term Debt	2,070.767	47.68%	2,106.863	57.81%	1,122.999	42.19%	808.005	33.76%	1,006.394	40.65%	44.42%
Short-term Debt	848.700	19.54%	270.500	7.42%	346.400	13.01%	296.100	12.37%	431.700	17.44%	13.96%
Common Equity	1,423.785	32.78%	1,267.022	34.77%	1,192.409	44.80%	1,289.240	53.87%	1,037.539	41.91%	41.62%
	4,343.252	100.00%	3,644.385	100.00%	2,661.808	100.00%	2,393.345	100.00%	2,475.633	100.00%	100.00%
Spire Inc.											
Long-term Debt	2,082.600	40.62%	1,900.100	40.35%	1,995.000	44.69%	1,833.700	45.84%	1,771.500	48.10%	43.92%
Short-term Debt	743.200	14.50%	553.600	11.76%	477.300	10.69%	398.700	9.97%	338.000	9.18%	11.22%
Common Equity	2,301.000	44.88%	2,255.400	47.89%	1,991.300	44.61%	1,768.200	44.20%	1,573.600	42.72%	44.86%
	5,126.800	100.00%	4,709.100	100.00%	4,463.600	100.00%	4,000.600	100.00%	3,683.100	100.00%	100.00%

Five-Year Average Capital Structure	
Long-term Debt	40.29%
Short-term Debt	12.10%
Common Equity	47.60%
	100.00%

Source: Compustat (data in millions)
April 2020

Accessed on April 14, 2021

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set 1 RR

Question No. I & E RR 1-003-D:

Reference Columbia Exhibit No. 400, page 13 of 28, Schedule 6. Provide all supporting documentation for the interest rates associated with all long-term debt issuances that have not yet been issued.

Response:

Please refer to I&E-RR-003 Attachment A to this response that provides the basis for the forecast interest rates on long-term debt to be issued in March 2021 and June 2022. It should be noted that the interest rate on the issue scheduled for March 2021 was established for that issue prior to the preparation of Exhibit No. 400. There was insufficient time to update the estimate with the actual rate prior to the time the overall rate of return was finalized. The actual coupon rate is provided in I&E-RR-003 Attachment B. Utilizing the actual 3.6521% interest rate on the $110 million promissory note issued on March 31, 2021, changes the FTY embedded cost of long-term debt to 4.70% (from 4.65% in the original filing) and embedded cost of total debt 4.40% (from 4.36% in the original filing). The respective debt cost rates for the FPFTY are 4.58% for long-term debt (from 4.54% in the original filing) and 4.26% for total debt (from 4.23% in the original filing.)

	2019		
	Interest Charges	**Long-term Debt**	**Debt Cost**
Atmos Energy Corp	110.80	3,529.45	3.14%
Chesapeake Utilities	22.92	450.06	5.09%
Nisource Inc	386.40	7,907.80	4.89%
Northwest Natural Gas Co	42.69	806.80	5.29%
One Gas Inc.	67.28	1,314.06	5.12%
South Jersey Industries Inc	120.48	2,070.77	5.82%
Spire Inc.	104.40	2,082.60	5.01%
	Range:	**Low**	**3.14%**
		High	**5.82%**
		Average	**4.91%**

Source: Compustat
April 2020

Accessed on April 14, 2021

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set 1 RR

Question No. I & E RR 1-002-D:

Reference Columbia Statement No. 8, page 18, lines 13-16 concerning the short-term debt cost rate:

A. Provide the source of the 0.55% LIBOR rate used to calculate the short-term debt cost rate.

B. Provide the calculation and explanation of the 30-basis point spread used to calculate the short-term debt cost rate.

Response:

A. Please refer to Attachment A to this response.

B. See part A above. Attachment B shows the calculation of the 30-basis point spread. The 30-basis point spread was derived by looking at the average spread between our actual commercial paper rate and 3M Libor during 2019-2020.

Enter # <GO> for details

Chart | Export | Disclaimer | Page 1/3 **Bond Yield Forecasts**

Region: G7 | Spread: 2 Year - 10 Year

	Rate	Market Yld	Q1 21	Q2 21	Q3 21	Q4 21	Q1 22	Q2 22	Q3 22	Q4 22	Q1 23	Q2 23
	United States											
1)	US 30-Year	1.93	1.78	1.90	1.96	2.04	2.12	2.22	2.27	2.35	2.47	2.51
2)	US 10-Year	1.15	1.06	1.19	1.26	1.34	1.40	1.51	1.57	1.68	1.77	1.76
3)	US 5-Year	0.46	0.49	0.59	0.62	0.70	0.78	0.86	0.94	1.05	1.12	1.16
4)	US 2-Year	0.11	0.18	0.22	0.27	0.31	0.38	0.45	0.50	0.57	0.67	0.72
5)	US 3-Month Libor	0.20	0.29	0.30	0.32	0.34	0.40	0.46	0.51	0.55	0.64	0.68
6)	Fed Funds Rate - Upper Bound	0.25	0.25	0.25	0.25	0.30	0.30	0.30	0.35	0.35	0.40	0.45
7)	Fed Funds Rate - Lower Bound	0.00	0.00	0.00	0.02	0.03	0.05	0.06	0.08	0.10	0.15	0.18
	2 Year - 10 Year Spread	1.04	0.88	0.96	0.99	1.03	1.02	1.06	1.07	1.11	1.10	1.03
	Germany											
8)	Germany 10-Year	-0.46	-0.51	-0.43	-0.35	-0.32	-0.24	-0.14	-0.08	-0.05	0.08	0.09
9)	Germany 2-Year	-0.72	-0.69	-0.66	-0.63	-0.61	-0.57	-0.53	-0.50	-0.44	-0.41	-0.39
10)	3-Month Euribor	-0.54	-0.50	-0.49	-0.48	-0.47	-0.46	-0.46	-0.45	-0.44	-0.41	-0.40
11)	ECB Main Refinancing Rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12)	ECB Deposit Rate	-0.50	-0.50	-0.50	-0.50	-0.50	-0.51	-0.51	-0.50	-0.50	-0.49	-0.47
	2 Year - 10 Year Spread	0.26	0.18	0.23	0.28	0.29	0.34	0.39	0.42	0.39	0.49	0.47
	United Kingdom											
13)	UK 10-Year	0.46	0.30	0.39	0.43	0.53	0.55	0.62	0.70	0.79	0.86	0.98
14)	UK 2-Year	-0.05	-0.04	0.00	0.03	0.08	0.12	0.18	0.24	0.35	0.33	0.33
15)	UK 3-Month Libor	0.05	0.06	0.07	0.14	0.09	0.12	0.13	0.15	0.19	0.26	0.29
16)	BOE Bank Rate	0.10	0.10	0.10	0.10	0.10	0.15	0.15	0.15	0.20	0.45	0.50
	2 Year - 10 Year Spread	0.51	0.34	0.40	0.40	0.45	0.43	0.44	0.45	0.44	0.54	0.66

2021-22 CP Rate Forecast		
	2021	2022
3 Month Libor*	0.34%	0.55%
CP Spread**	0.30%	0.30%
All In Rate	**0.64%**	**0.85%**

** Analyst projections from Bloomberg*
*** Average CP spread to 3 Month Libor*

I&E Exhibit No. 2
Schedule 6
Page 1 of 2

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 39, No. 12, December 1, 2020

Wolters Kluwer

I&E Exhibit No. 2
Schedule 6
Page 2 of 2

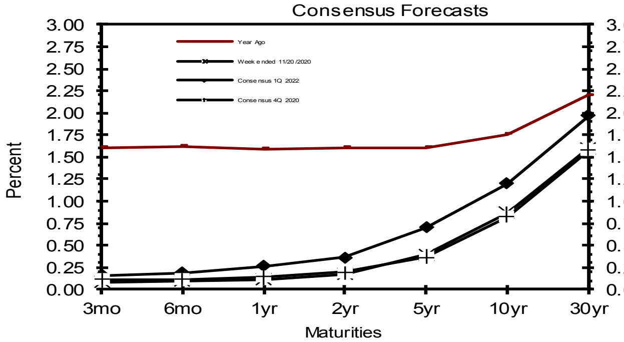
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov 20	Nov 13	Nov 6	Oct 30	Oct	Sep	Aug	3Q 2020	2020	2021	2021	2021	2021	2022
Federal Funds Rate	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.09	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
LIBOR, 3-mo.	0.22	0.22	0.22	0.22	0.22	0.24	0.25	0.25	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Commercial Paper, 1-mo.	0.10	0.10	0.09	0.10	0.09	0.09	0.09	0.10	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Treasury bill, 3-mo.	0.08	0.10	0.10	0.10	0.10	0.11	0.10	0.11	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Treasury bill, 6-mo.	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.13	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**
Treasury bill, 1 yr.	0.11	0.12	0.13	0.12	0.13	0.13	0.13	0.14	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**
Treasury note, 2 yr.	0.17	0.18	0.15	0.16	0.15	0.13	0.14	0.14	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Treasury note, 5 yr.	0.39	0.43	0.36	0.36	0.34	0.27	0.27	0.27	**0.4**	**0.4**	**0.5**	**0.6**	**0.6**	**0.7**
Treasury note, 10 yr.	0.87	0.93	0.83	0.82	0.79	0.68	0.65	0.65	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**	**1.2**
Treasury note, 30 yr.	1.60	1.69	1.60	1.60	1.57	1.42	1.36	1.36	**1.6**	**1.6**	**1.8**	**1.8**	**1.9**	**2.0**
Corporate Aaa bond	2.53	2.66	2.64	2.68	2.65	2.56	2.48	2.49	**2.5**	**2.5**	**2.6**	**2.7**	**2.8**	**2.8**
Corporate Baa bond	3.08	3.20	3.22	3.27	3.27	3.20	3.09	3.14	**3.5**	**3.6**	**3.7**	**3.7**	**3.8**	**3.8**
State & Local bonds	2.78	2.85	2.89	2.92	2.93	2.92	2.88	2.93	**2.5**	**2.5**	**2.6**	**2.7**	**2.8**	**2.8**
Home mortgage rate	2.72	2.84	2.78	2.81	2.83	2.89	2.94	2.95	**2.9**	**2.9**	**3.0**	**3.0**	**3.1**	**3.1**

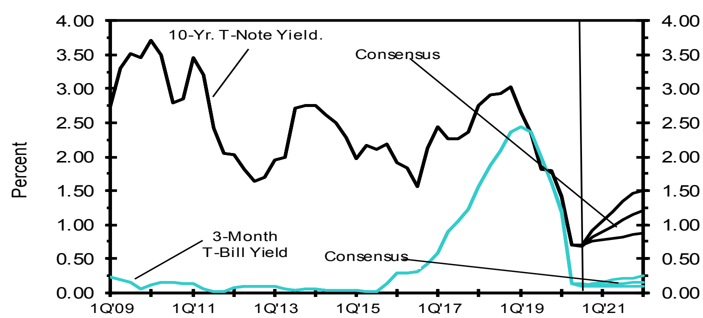
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2018	2019	2019	2019	2019	2020	2020	2020	2020	2020	2020	2021	2021	2022
Fed's AFE $ Index	109.4	109.4	110.3	110.5	110.3	111.2	112.4	107.2	**106.1**	**106.3**	**106.0**	**105.8**	**105.9**	**105.6**
Real GDP	1.3	2.9	1.5	2.6	2.4	-5.0	-31.4	33.1	**3.7**	**2.6**	**4.0**	**4.0**	**3.6**	**3.0**
GDP Price Index	1.8	1.2	2.5	1.5	1.4	1.4	-1.8	3.6	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**
Consumer Price Index	1.3	0.9	3.0	1.8	2.4	1.2	-3.5	5.2	**2.0**	**1.9**	**1.9**	**2.0**	**2.0**	**2.0**
PCE Price Index	1.4	0.6	2.5	1.4	1.5	1.3	-1.6	3.7	**1.8**	**1.7**	**1.9**	**1.9**	**1.9**	**1.9**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP/PCE Chained Price Indexes are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

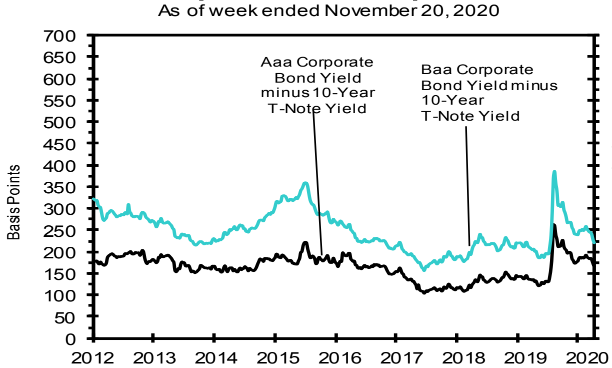
U.S. Treasury Yield Curve
Week ended November 20, 2020 & Year Ago vs. 4Q 2020 & 1Q 2022 Consensus Forecasts



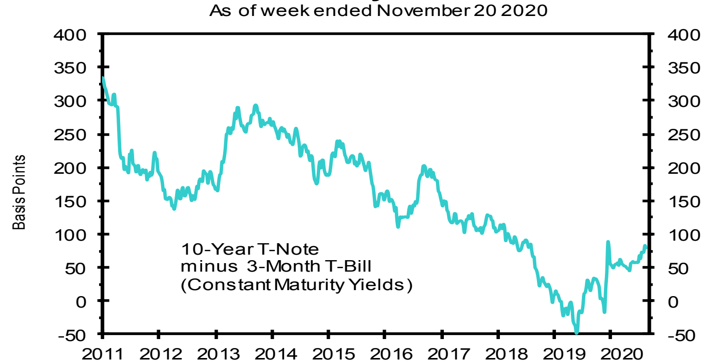
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average) Forecast



Corporate Bond Spreads
As of week ended November 20, 2020



U.S. Treasury Yield Curve
As of week ended November 20 2020



Dividend Yields of Seven Company Proxy Group

Company	Atmos Energy Corp	Chesapeake Utilities	Nisource Inc	Northwest Natural Gas Co	One Gas Inc.	South Jersey Industries Inc	Spire Inc.
Symbol	*ATO*	*CPK*	*NI*	*NWN*	*OGS*	*SJI*	*SR*
Div	2.70	1.96	0.92	1.93	2.48	1.32	2.72
52-wk low	84.59	72.89	21.09	41.71	65.51	18.24	50.58
52-wk high	111.34	121.04	27.24	67.24	90.24	30.25	77.99
Spot Price	99.09	116.81	24.51	53.91	77.81	24.27	76.20
Spot Div Yield	2.72%	1.68%	3.75%	3.58%	3.19%	5.44%	3.57%
52-wk Div Yield	2.76%	2.02%	3.81%	3.54%	3.18%	5.44%	4.23%
Average	**2.74%**	**1.85%**	**3.78%**	**3.56%**	**3.19%**	**5.44%**	**3.90%**

	Average
Spot Div Yield	**3.42%**
52-wk Div Yield	**3.57%**
Average	**3.49%**

Source:	Barrons	April 14, 2021
	Value Line	February 26, 2021

Five-Year Growth Estimate Forecast for Proxy Group

Company	Symbol	Yahoo	Zacks	Morningstar	Value Line	Average
		Source				
Atmos Energy Corp	ATO	7.17%	7.30%	7.10%	7.00%	7.14%
Chesapeake Utilities	CPK	4.74%	NMF	0.00%	8.50%	4.41%
Nisource Inc	NI	4.37%	6.20%	4.60%	10.00%	6.29%
Northwest Natural Gas Co	NWN	3.10%	NMF	3.10%	5.50%	3.90%
One Gas Inc.	OGS	5.00%	5.00%	NMF	6.50%	5.50%
South Jersey Industries Inc	SJI	4.40%	4.40%	NMF	10.50%	6.43%
Spire Inc.	SR	5.70%	5.00%	5.10%	9.00%	6.20%
Average						**5.70%**

Source:
(From Internet)
April 14, 2021

Expected Market Cost Rate of Equity

Using Data for the Proxy Group of Seven Natural Gas Companies

5-Year Forecasted Growth Rates

	Time Period		Adjusted Dividend Yield (1)	Growth Rate (2)	Expected Return on Equity (3=1+2)
(1)	**52-Week Average**		3.57%	5.70%	9.27%
	Ending:	April 14, 2021			
(2)	**Spot Price**		3.42%	5.70%	9.12%
	Ending:	April 14, 2021			
(3)	**Average:**		**3.49%**	**5.70%**	**9.19%**

Sources: Value Line February 26, 2021
Barrons April 14, 2021

Company	Beta
Atmos Energy Corp	0.80
Chesapeake Utilities	0.80
Nisource Inc	0.85
Northwest Natural Gas Co	0.80
One Gas Inc.	0.80
South Jersey Industries Inc	1.05
Spire Inc.	0.85
Average beta for CAPM	**0.85**

Source:
Value Line
February 26, 2021

Risk-Free Rate

Treasury note 10-yr Note	Yield
3Q 2021	1.70
4Q 2021	1.80
1Q 2022	1.90
2Q 2022	2.00
3Q 2022	2.00
2022-2026	2.00
Average	**1.90**

Source:
Blue Chip
April 1, 2021 and December 1, 2020

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	1.80%		5.74%	(a)	7.54%
S&P 500	1.51%	(b)	12.60%		14.11%
Average Expected Market Return				=	**10.82%**

(a) ((1+25%)^.25) -1) Value Line forecast for the 3 to 5 year index appreciation is 25%
(b) S&P 500 multiplied by half the growth rate

Sources:

Value Line	4/16/2021
S&P 500 Dividend Yield (Barrons)	4/14/2021
S&P 500 Growth Rate (Morningstar)	4/14/2021

CAPM with Forecasted Return

Re	Required return on individual equity security
Rf	Risk-free rate
Rm	Required return on the market as a whole
Be	Beta on individual equity security

Re = Rf+Be(Rm-Rf)

Rf =	1.9000
Rm =	10.8233
Be =	0.85
Re =	**9.48**

Sources:

Value Line	February 26, 2021
Blue Chip	April 1, 2021 and December 1, 2020

I&E Statement No. 2-SR
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Surrebuttal Testimony

of

Christopher Keller

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

TABLE OF CONTENTS

INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTOPHER KELLER WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND THE SCHEDULES IN I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made by Columbia Gas of Pennsylvania, Inc. (Columbia or Company) witness Paul R. Moul (Columbia Statement No. 8-R) in his rebuttal testimony regarding rate of return topics including the cost of common equity and the overall fair rate of return, which will be applied to the Company's rate base.

Q. DID THE COMPANY PROVIDE AN UPDATE TO ITS RATE OF RETURN?

A. Yes. The Company provided an update to its cost of long-term debt. The Company is now requesting a cost of long-term debt of 4.58% to reflect the cost of a new issue of promissory notes issued in March 2021 (Columbia Statement No. 8-R, p. 9, lines 17-18), which I reflected in direct testimony (I&E Statement No. 2, p. 11, lines 16-19). The Company's update to its cost of long-term debt is an increase of 0.04% (4.58% - 4.54%) to its initial claim of 4.54% (Columbia Statement No. 8-R, p. 9). Below is the Company's updated rate of return claim (Columbia Exhibit No. 400R, Schedule 1, p. 1):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	41.77%	4.58%	1.91%
Short-Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	10.95%	5.95%
Total	100.00%		7.89%

SUMMARY OF MR. MOUL'S REBUTTAL TESTIMONY

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RECOMMENDATIONS MADE IN DIRECT TESTIMONY.

A. Mr. Moul disputes my recommendations regarding an appropriate proxy group, the use of methods other than the Discounted Cash Flow (DCF), disallowance of his leverage adjustment, the Capital Asset Pricing Model (CAPM) risk-free rate, rejection of his leverage adjusted betas, disallowance of his size adjustment, and my disagreement with his use of the Risk Premium (RP) and Comparable Earnings (CE) methods. Additionally, Mr. Moul opines that the Commission-determined Distribution System Improvement Charge (DSIC) rates should serve as the bare minimum cost of equity in this proceeding.

<u>DSIC RATES</u>

Q. PLEASE SUMMARIZE MR. MOUL'S THEORY THAT DSIC RATES SHOULD SERVE AS THE MINIMUM AUTHORIZED COST OF EQUITY IN THIS PROCEEDING.

A. Mr. Moul claims that the cost of equity in a rate case should not be lower than the Company's DSIC rate. He makes this assertion on the basis that: (1) investments carrying the DSIC return should not be penalized with a lower return when they are included in rate base when setting base rates; and (2) DSIC investments receive a 'true-up' such that the achieved returns on DSIC investments equal the intended returns in those proceedings and that there is no true-up of the achieved return in a rate case. Mr. Moul suggests there is additional risk associated with achieving a particular return in base rates because there is no true up (Columbia Statement No. 8-R, pp. 11-12).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ASSERTION THAT THE COMPANY'S DSIC RATE SHOULD SERVE AS THE MINIMUM AUTHORIZED COST OF EQUITY IN THIS PROCEEDING?

A. Mr. Moul's comparison between the I&E recommended return on equity in this proceeding and the Company's DSIC rate is misguided. The DSIC return for utilities is calculated differently than the equity return in a base rate case and does not represent the full scope of risk for a given utility company. The DSIC rate is designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring the existing aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. To suggest the cost of equity must be at or above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest. Additionally, the DSIC rate establishes a benchmark above which a utility company is considered "overearning." As such, the DSIC rate does not serve as a proper measurement of a subject utility's cost of equity in a rate case proceeding. In fact, 66 Pa. C.S. § 1358(b)(3) states the following:

> The distribution system improvement charge shall be reset at zero if, in any quarter, data filed with the commission in the utility's most recent annual or quarterly earnings report show that the utility will earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the distribution system improvement charge.

Finally, the DSIC mechanism serves to lower a utility's risk because it reduces the lag time in the recovery of a company's capital outlays.

PROXY GROUP

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR PROXY GROUP.

A. Mr. Moul opines that using the percentage of revenue as a criterion for a proxy group is incorrect and that the percentage of gas assets to total assets is a more appropriate criterion because the margins of utility-based activities are not comparable to that of non-utility business segments (Columbia Statement No. 8-R, pp. 17-18).

Q. DO YOU AGREE WITH MR. MOUL'S ASSERTION THAT THE PERCENTAGE OF GAS UTILITY ASSETS TO TOTAL ASSETS IS A MORE APPROPRIATE CRITERION?

A. No. Calculating the percentage of utility assets that make up the total assets of a company is not always a reliable way of determining if a business is primarily a regulated utility. Assets are accounted for at the original cost minus depreciation, which means that the value of an asset depends on its age. Therefore, it is possible for the regulated utility segment of a company to predominately have assets that are depreciated. Although a utility may have assets that are significantly depreciated, it does not always indicate the level of business a company does. A parent company can have most of its utility assets depreciated but still do more business as a utility than it does in another business segment.

Another reason that the percentage of utility business is not always accurately represented by using the percentage of utility assets to total assets is that there are differences between businesses in the amount of capital needed. A utility with all new equipment may need a large amount of assets to produce a small level of cash flow while another business may need only a small amount of assets to produce a large level of cash flow. Therefore, comparing the assets of a gas utility segment to the total assets of a company is not an appropriate criterion.

Q. MR. MOUL ARGUES THAT YOUR CRITERION THAT 50% OR MORE OF REVENUE MUST BE GENERATED FROM THE GAS UTILITY INDUSTRY FOR INCLUSION IN THE PROXY GROUP IS NOT APPROPRIATE. DO YOU AGREE?

A. No. Revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If fewer than 50% of revenues come from the regulated gas business sector, a company is not comparable to the subject utility as it does not provide a similar level of regulated business (I&E Statement No. 2, p. 9).

Q. OUT OF THE TWO COMPANIES THAT MR. MOUL USES IN HIS PROXY GROUP THAT YOU DO NOT USE IN YOURS, WHICH WERE EXCLUDED FOR FAILING TO MEET THE CRITERION THAT 50% OR MORE REVENUES MUST BE GENERATED FROM THE GAS UTILITY INDUSTRY?

A. As explained in my direct testimony, both companies, New Jersey Resources Corp. and Southwest Gas Holdings, Inc. were excluded for not meeting my criterion that 50% or more of revenues must be generated from regulated gas utility operations (I&E Statement No. 2, p. 9). There were other companies that did not meet this criterion as well, however, they were previously eliminated for not meeting one of the other criteria required to be included in my proxy group.

Q. DO YOU HAVE ANY CHANGES TO YOUR PROXY GROUP?

A. No. For the reasons discussed above, the percentage of revenue is an appropriate criterion. As New Jersey Resources Corp. and Southwest Gas Holdings, Inc. include an insufficient percentage of regulated gas revenues, they should not be included in the proxy group and compared to Columbia.

<u>DISCOUNTED CASH FLOW</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. Moul agrees that the results of a DCF analysis should be given weight but disagrees with my approach. Mr. Moul also disagrees with my results based on the outcomes of certain individual companies and my recommendation to reject his leverage adjustment (Columbia Statement No. 8-R, pp. 18-23).

<u>EXCLUSIVE USE OF THE DCF</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE DCF.

A. Mr. Moul explains that the use of more than one method provides a superior foundation for the cost of equity determination. Mr. Moul claims that the use of more than one method will capture the multiplicity of factors that motivate investors (Columbia Statement No. 8-R, pp. 18-19).

Q. WERE ANY METHODS OTHER THAN THE DCF EMPLOYED IN YOUR ANALYSIS?

A. Yes. Although my recommendation was based on the results of my DCF analysis, I also employed the CAPM as a comparison. The result of my DCF analysis is 9.19% while the result of my CAPM analysis is 9.48%, both of which are significantly lower than the Company's claim of 10.95%. For the reasons discussed in my direct testimony, the DCF method is the most reliable (I&E Statement No. 2, pp. 16-17). I have considered the fact that no method can perfectly predict the return on equity, which is why I also use the CAPM as a comparison to the DCF. Although no one method can capture every factor that influences an investor, including the results of methods less reliable than the DCF does not make the end result more reliable or more accurate. As a result, I stand by my method of using the DCF with a CAPM comparison, which is consistent with the methodology historically used by the Commission in base rate proceedings, even as recently as 2017, 2018, 2020, and 2021.[1]

EVALUATING THE DCF BASED ON INDIVIDUAL RESULTS

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING THE RESULTS OF YOUR DCF?

A. Mr. Moul argues that when some results are unreasonable on their face, the application or the reliability of that method must be questioned. He points to the results of three of my proxy group companies and claims that they fall into that category. Mr. Moul attempts to support his argument by asserting that I

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[1] *Pa. PUC v. City of DuBois – Bureau of Water*; Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company;* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA;* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.;* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131. *Pa. PUC v. PECO Energy Company – Gas Division*; Docket No. R-2020-3018929 (Order Entered June 22, 2021). *See generally* Disposition of Return of Rate on Common Equity, p. 171.

erroneously included Value Line's growth projections for Chesapeake Utilities Corp., Northwest Natural Holding Co., and One Gas, Inc., explaining that my inclusion of these companies was unreasonable as their inclusion results in a DCF returns that are below 9.0% (Columbia Statement No. 8-R, pp. 18-20).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ATTEMPT TO DISAGGREGATE YOUR RESULTS?

A. Generally, to remove individual companies or data points based solely on the results creates a bias and can be described as tampering with market-based results. I chose criteria for my proxy group with the intention of creating a group that is comparable to Columbia, and then calculated a DCF from the companies that fit my criteria.

<u>LEVERAGE ADJUSTMENT</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING HIS RECOMMENDED LEVERAGE ADJUSTMENT.

A. First, Mr. Moul clarifies that his "leverage adjustment" is not a traditional "market-to-book" ratio adjustment. Next, he states that credit rating agencies do not measure the market-required cost of equity for a company, nor are they concerned with how it is applied in the rate-setting context. Instead, credit rating agencies are only concerned with the interests of lenders and the timely payment of interest and principal by utilities. Mr. Moul then questions my references to prior Commission Orders. Finally, Mr. Moul disagrees with my assertion that investors base their decisions on book value capitalization (Columbia Statement No. 8-R, pp. 24-26).

Q. HAVE YOU CLAIMED THAT MR. MOUL'S ADJUSTMENT IS A MARKET-TO-BOOK RATIO ADJUSTMENT?

A. No. As I stated in my direct testimony, Mr. Moul does not propose to change the capital structure of the utility (a leverage adjustment), nor does he propose to apply the market-to-book ratio to the DCF model (a market-to-book adjustment) (I&E Statement No. 2, p. 36).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY CONCERNING CREDIT RATING AGENCIES?

A. Mr. Moul has supported the I&E argument that his proposed leverage adjustment is not needed by stating that the credit rating agencies are only concerned with the timely payment of interest and principal by utilities (Columbia Statement No. 8-R, p. 24). Mr. Moul's stated need for the leverage adjustment is based on his assertion that the difference between the book value capital structure and his market value capital structure causes a financial risk difference (Columbia Statement No. 8, p. 26).

Financial risk does relate to the capital structure of a company, but it is created by the financing decisions (the use of debt or equity) and the amount of leverage or debt a company chooses to finance its assets. Financial risk and the book value capital structure of a company are represented in the income statement, part of what is evaluated by rating agencies. Mr. Moul agrees with me that credit rating agencies use a company's financial statements in their analysis to assess financial risk and determine creditworthiness (Columbia Statement No. 8-R, p. 24).

Q. SUMMARIZE MR. MOUL'S RESPONSE TO YOUR REFERENCING PRIOR COMMISSION ORDERS.

A. Mr. Moul refers to the discussion in my direct testimony where I point to four recent cases (Aqua Pennsylvania, Inc., City of Lancaster – Bureau of Water, UGI Utilities, Inc. – Electric Division, and Columbia's last base rate case) where the Commission has rejected a "leverage adjustment." He claims that the adjustment proposed in the City of Lancaster case was much different than what he is proposing in this proceeding. Additionally, Mr. Moul explains that even though the Commission declined to make a "leverage adjustment" in the Aqua Pennsylvania case, it does not invalidate its use. Further, Mr. Moul states, "Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance." Further, Mr. Moul states that the Commission granted basis points for management performance in the UGI Electric case to arrive at the return on equity of 9.85%. Finally, Mr. Moul states that in the 2020 case the Company accepted I&E's DCF return without regard to the leverage adjustment or management performance (Columbia Statement No. 8-R, pp. 24-25).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE REFERENCED PRIOR COMMISSION ORDERS IN YOUR DIRECT TESTIMONY?

A. In this proceeding, Mr. Moul is recommending a 217-basis point "leverage adjustment." To be clear, the Commission did in fact refuse to accept the leverage adjustment in the Aqua case by stating "…we reject the ALJ's recommendation to allow a 65 basis point leverage adjustment."[2] The management performance points awarded to Aqua were case-specific and in no way related to the proposed leverage adjustment. Regarding the City of Lancaster case, the Commission did not reject the leverage adjustment based on the manner in which it was calculated, but rather, the Commission stated, "…the ALJ's recommendation is in error as any adjustment to the results of the market based DCF as we have previously adopted are unnecessary and will harm ratepayers."[3] Regarding the UGI Electric case, the Commission concluded that, "…an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to

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[2] *Pa. PUC v. Aqua Pennsylvania, Inc.*; Docket No. R-00072711, pp. 38-39 (Order entered July 31, 2008).
[3] *Pa. PUC v. City of Lancaster – Bureau of Water*; Docket No. R-2010-2179103, p. 79 (Order entered July 14, 2011).

include a leverage adjustment in our calculation of the DCF cost of equity."[4] Regarding Columbia's most recent case, the Commission stated, "… we have adopted the ALJ's recommendation to use I&E's DCF methodology utilizing I&E's dividend yield of 3.34% and growth rate of 6.52%. As noted above, the ALJ did not specify a recommended cost of equity for Columbia in her Recommended Decision. However, we note that I&E's methodology results in an ROE of 9.86%."[5] The ALJ's Recommended Decision stated the following:

> The ALJ agrees with BIE's reasoning that Columbia Gas' calculated return on equity was flawed for five reasons: (1) the weights given to the results of the Company's CAPM, RP, and CE analyses; (2) certain aspects of Columbia's discussion of risk; (3) Columbia Gas' application of the DCF including the forecasted growth rate and leverage adjustment used; (4) Columbia's inclusion of a size adjustment, reliance on the 30-year Treasury Bond for the risk- free rate, and the use of a double-adjusted *beta* in the CAPM analysis; and (5) the Company's request for an additional 20 basis points for "strong management performance" is unjustified.[6]

While the Company accepted I&E's DCF return without regard to the leverage adjustment or management performance in the last base rate case, in the Recommended Decision, the ALJ clearly rejected the Company's proposed leverage adjustment and the Commission agreed with the ALJ's Recommended Decision, which rejected the Company's proposed leverage adjustment.

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[4] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058, pp. 93-94 (Order entered October 25, 2018).

[5] *Pa. PUC v. Columbia Gas of Pennsylvania*; Inc. Docket No. R-2020-3018835, p. 137 (Order entered February 19, 2021).

[6] *Pa. PUC v. Columbia Gas of Pennsylvania*; Inc. Docket No. R-2020-3018835. Recommended Decision, pp. 184-185.

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ASSERTION THAT INVESTORS DO NOT BASE THEIR DECISIONS ON BOOK VALUE, BUT RATHER THE RETURN THEY WILL EARN ON THE DOLLARS THEY INVEST?

A. Mr. Moul's assertion that an investor is concerned with the return earned on dollars invested and not "some accounting value of little relevance to them," (Columbia Statement No. 8-R, pp. 25-26) is unsupported. Clearly an investor takes financial risk into consideration when determining a required return. In addition, the market capitalization information included in Value Line's reports and discussed by Mr. Moul is not the same as market value capital structure (Columbia Statement No. 8-R, pp. 25-26). Market capitalization refers to the number of shares outstanding multiplied by the current price. A market value capital structure refers to the ratio of market debt to market equity, which is not included in Value Line's reports. Therefore, Mr. Moul's contention that Value Line includes market capitalization data does not offer any support for his leverage adjustment.

Q. HAS MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY CONCERNING HIS PROPOSED LEVERAGE ADJUSTMENT CAUSED YOU TO CHANGE YOUR RECOMMENDATION?

A. No. For the reasons discussed above, I continue to recommend that Mr. Moul's leverage adjustment be rejected.

<u>CAPITAL ASSET PRICING MODEL</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR APPLICATION OF THE CAPM.

A. Mr. Moul opines that my CAPM analysis understates the cost of equity for several reasons, including my use of the yield on 10-year Treasury Notes for my risk-free rate, failure to use leverage adjusted betas, and rejection of his size adjustment (Columbia Statement No. 8-R, p. 27). Each of these topics are discussed in more detail below.

<u>RISK-FREE RATE</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE.

A. Mr. Moul claims that his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Note because a longer-term bond is less susceptible to Federal policy actions (Columbia Statement No. 8-R, p. 27).

Q. DO YOU AGREE WITH MR. MOUL THAT USING THE YIELD OF A 30-YEAR U.S. TREASURY BOND IS MORE APPROPRIATE DUE TO A LONGER-TERM BOND BEING LESS SUSCEPTIBLE TO FEDERAL POLICY ACTIONS?

A. No. As stated in my direct testimony, I chose the 10-year Treasury Note which balances the shortcomings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is more appropriate (I&E Statement No. 2, pp. 23-24). Further, as also pointed out in my direct testimony, the Commission has recently agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[7]

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR RISK-FREE RATE USED IN THE CAPM FORMULA.

A. Mr. Moul opines that I have incorrectly given weight to the yield on the 10-year Treasury Note for the third and fourth quarters of 2021 and the first, second, and third quarters of 2022 as I do for the entire five-year period encompassing 2022 to 2026. Then, Mr. Moul incorrectly recalculates the risk-free rate by averaging the 10-year treasury yield forecasts by year from 2021 through 2026 to inflate my calculated risk-free rate of 1.90% to 2.50% (Columbia Statement No. 8-R, pp. 27-28).

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[7] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 p. 99 (Order entered October 25, 2018).

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS OF YOUR RISK-FREE RATE?

A. No. Mr. Moul's new calculation proposes to give equal weight to each separate year from 2021 to 2026. The flaw with this approach is that the further out into the future one forecasts, the less reliable and more speculative the estimates become; therefore, to give the less reliable estimates equal weight would not be prudent. It is more appropriate to weight the quarters and years as I have done in my direct testimony (I&E Exhibit No. 2, Schedule No. 11). My calculation provides a more accurate estimation of the risk-free rate during the Fully Projected Future Test Year, as the further out one forecasts, the less reliable the information becomes.

<u>LEVERAGED BETAS</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE USE OF LEVERAGE-ADJUSTED BETAS.

A. Mr. Moul simply mentions my "failure to use leverage adjusted betas…" (Columbia Statement No. 8-R, p. 27). He does not offer an explanation beyond what he argued in his direct testimony.

Q. IS THE USE OF LEVERAGE-ADJUSTED BETAS IN CAPM ANALYSES APPROPRIATE?

A. No. As stated in my direct testimony, Mr. Moul's adjustment only serves to inflate the result of his CAPM analysis. Enhancements such as leverage adjusted betas are unwarranted in CAPM analyses for the same reasons that enhancements are unwarranted for DCF results. Until this type of adjustment is demonstrated in academic literature to be valid, such leverage-adjusted betas in a CAPM should be rejected (I&E Statement No. 2, pp. 41-42).

SIZE ADJUSTMENT

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. In direct testimony, I stated that Mr. Moul's 102 basis point CAPM size adjustment is unnecessary because none of the technical literature he cited in his direct testimony supporting investment adjustments related to the size of a company is specific to the utility industry. In addition, I presented an article by Dr. Annie Wong that demonstrated there is no need to make an adjustment for the size of a company in utility rate regulation (I&E Statement No. 2, pp. 42-43).

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. Mr. Moul states the distinction between regulated utilities and unregulated industrial companies from the technical literature that he cites is not enough to reject his size adjustment and that the size adjustment he derived from the Ibbotson study included public utilities. Mr. Moul also states that enormous changes have occurred in the industry since the article, "Utility Stocks and the Size Effect: An Empirical Analysis," by Dr. Annie Wong was published. He also references the Fama/French study, "The Cross-Section of Expected Stock Returns," to illustrate that his size adjustment is a separate factor from beta which helps explain systematic risk and returns (Columbia Statement No. 8-R, pp. 29-30).

Q. DO THE FAMA/FRENCH STUDY AND THE IBBOTSON STUDY REFUTE DR. WONG'S ARTICLE?

A. No. As stated in my direct testimony, Dr. Wong's article presents evidence that although a size effect may exist for industrial stocks, it does not exist for utility stocks. As the Fama/French study is not specific to utility stocks, and although the Ibbotson study included public utilities, this does not adequately demonstrate that a size effect exists in the utility industry. In addition, the size effect that exists for industrial stocks varies to such an extent that it is difficult to predict. The difficulty in predicting the effect of size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation: 2015 Yearbook*. As stated on page 100 of the SBBI Yearbook,

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference

> between the first and 10th decile returns was far more substantial. The divergence in the performance of small- and large- cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states,

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states,

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Q. DOES THE TIME WHICH HAS ELAPSED SINCE AN ARTICLE WAS WRITTEN NECESSARILY INVALIDATE ITS RESULTS?

A. No. Although Mr. Moul states that enormous changes have occurred in the industry since the 1960s, he presents no evidence that these "changes" have caused the need for a size adjustment. To the contrary, Dr. Wong's study demonstrated that one does *not* need to be made in the regulated utility industry. As stated in my direct testimony, absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. MOUL'S SIZE ADJUSTMENT?

A. I continue to recommend that his use of the 1.02% size adjustment be disallowed in calculating the CAPM.

Q. MR. MOUL HAS RECALCULATED YOUR CAPM RESULTS. DO YOU AGREE WITH HIS RECALCULATION?

A. No. Mr. Moul's recalculation is incorrect for a couple of reasons. He used an inaccurate risk-free rate and an unnecessary size adjustment, as stated in both my direct testimony and above. Because of these factors, a recalculation of my CAPM results is imprudent and any recalculation provided by Mr. Moul of my CAPM results is unreliable and unnecessary.

<u>RISK PREMIUM</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE RP METHOD.

A. Mr. Moul opines that the RP approach should be given serious consideration because it is straight-forward, understandable, and uses a company's own borrowing rate. He claims it provides a direct and complete reflection of a utility's risk and return. Mr. Moul also states that I make an unfounded assertion that the RP method does not measure the current cost of equity as directly as the DCF (Columbia Statement No. 8-R, pp. 33-34).

Q. DO YOU AGREE WITH MR. MOUL THAT THE RP METHOD PROVIDES A DIRECT AND COMPLETE REFLECTION OF A UTILITY'S RISK AND RETURN?

A. No. The RP method produces an indirect measure when compared to the DCF method.

Q. PLEASE COMMENT ON THE INDIRECT MEASURE OF THE RP METHOD VERSUS THE MORE DIRECT MEASURE OF THE DCF METHOD.

A. Mr. Moul claims that my statement that the RP method does not measure the current cost of equity as directly as the DCF is without foundation. In my direct testimony, I have clearly illustrated how the two measures are different (I&E Statement No. 2, pp. 14-19). The main reason is that the RP method determines the rate of return on common equity indirectly by observing the cost of debt and adding to it an equity risk premium. The DCF measures equity more directly through the stock information (using equity information), whereas the RP method measures equity indirectly using debt information.

<u>**COMPARABLE EARNINGS**</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE CE METHOD.

A. Mr. Moul claims that using the CE method satisfies the comparability standard established in the *Hope* case. Additionally, he states, "…the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets" (Columbia Statement No.8-R, p. 35, lines 21-24). Finally, Mr. Moul addresses my statement that the use of 20% as the point where returns can be viewed as profitable is arbitrary, unjustified, and that there needs to be some point of demarcation to identify high returns and the 20% which he uses as the point where returns would be viewed as highly profitable (Columbia Statement No. 8-R, pp. 35-36).

Q. DO YOU AGREE THAT COMPANIES USED BY MR. MOUL IN HIS CE METHOD ARE COMPARABLE TO COLUMBIA?

A. No. As stated in my direct testimony, the companies in Mr. Moul's analysis are not utilities, and therefore, are too disparate to use in a CE analysis (I&E Statement No. 2, pp. 26-27). For example, the criteria Mr. Moul uses to choose the companies in his CE group results in the selection of companies such as Dolby Laboratories Inc., Graphic Packaging, J and J Snack Foods Corp., VeriSign Inc., and Yum Brands Inc. All these companies operate in industries very different from a utility company and operate under varying degrees of regulation. Also, most, if not all, of the companies Mr. Moul uses in his analysis are not monopolies in the sense that utilities are. This means that they have significantly more competition and would require a higher return for the added risk. Further, the CE method should be excluded because it is entirely subjective as to which companies are comparable and it is debatable whether historic accounting returns are representative of the future.

OVERALL RATE OF RETURN

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOUR DIRECT TESTIMONY?

A. No. I continue to support each recommendation made in I&E Statement No. 2.

Q. WHAT IS YOUR OVERALL RATE OF RETURN RECOMMENDATION?

A. I recommend the following rate of return for Columbia:

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	41.77%	4.58%	1.91%
Short-Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	9.19%	4.99%
Total	100.00%		6.93%

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Revenue Normalization Adjustment
Present Rate Revenues
Cost of Service Study
Scale Back of Rates

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INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ethan H. Cline. My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Columbia Gas of Pennsylvania, Inc.'s ("Columbia Gas" or "Company") requested base rate revenue increase of $98,278,240.[1] My testimony specifically addresses the following issues:

- Revenue Normalization Adjustment;
- Revenue allocation;
- Rate structure;
- Customer charge;
- Cost of Service allocation; and
- Scale back of rates.

<u>FPFTY REPORTING REQUIREMENTS</u>

Q. WHAT TEST YEAR DID THE COMPANY ELECT TO USE IN THIS PROCEEDING?

A. Columbia elected to base its rates on a fully projected future test year ("FPFTY") ending December 31, 2022. The Company also addressed a historic test year ("HTY") ended November 30, 2020 and future test year ("FTY") ending November 30, 2021 (Columbia St. No. 2, p. 2).

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[1] Columbia Gas Statement No. 4, p. 4.

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE WILL BE ASSOCIATED WITH THE INCLUSION OF THE FPFTY ENDING DECEMBER 31, 2022 FOR COLUMBIA?

A. The Company's claimed rate base for the FPFTY ending December 31, 2022 is $2,673,012,065 (Columbia Ex. No. 108, p. 3, col. 5). Columbia's rate base for the FTY ending November 30, 2021 is $2,344,784,616 (Columbia Ex. No. 108, p. 3, col. 3). Therefore, $328,227,449 ($2,673,012,065 – $2,344,784,616) of rate base additions are associated with the thirteen months between the end of FTY and the end of the FPFTY.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT COLUMBIA PROJECTS TO BE IN SERVICE DURING THE FTY ENDING NOVEMBER 30, 2021 AND THE FPFTY ENDING DECEMBER 31, 2022?

A. Yes. I recommend that the Company provide the Commission's Bureaus of Technical Utility Services and Investigation and Enforcement with an update to Columbia Exhibit No. 108, Schedule 1 no later than April 1, 2022, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2021. An additional update should be provided for actuals through December 31, 2022, no later than April 1, 2023.

Q. WHY DO YOU RECOMMEND THAT COLUMBIA PROVIDE THESE UPDATES?

A. I&E continues to believe that there is value in determining how closely Columbia's projected investments in future facility comport with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between Columbia's projected and actual results will help inform the Commission and the parties in Columbia's future rate cases as to the validity of Columbia's projections.

Using a FPFTY, Columbia is requesting ratepayers to pre-pay a return on its projected investment in future facilities that are not in place and providing service at the time the new rates take effect, but also are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investments comport with projections used in setting rates using the FPFTY provides the Commission with actual data to gauge the accuracy of Columbia's projected investments in future proceedings.

REVENUE NORMALIZATION ADJUSTMENT

Q. WHAT IS A REVENUE NORMALIZATION ADJUSTMENT?

A. A revenue normalization adjustment ("RNA") is a tariff provision that is "designed to 'break the link' between residential non-gas revenue received by the

Company and gas consumed by non-CAP residential customers." (Columbia St. No. 11, p. 27). In other words, the Company is proposing to stabilize its revenue level received from customers by enacting a "benchmark distribution revenue level" and adjusting revenues to that point regardless of actual usage levels.

Q. IS THE COMPANY PROPOSING AN RNA IN THIS PROCEEDING?

A. Yes. The Company is proposing to apply an RNA to its non-CAP residential customers (Columbia St. No. 3, p. 27).

Q. HOW DOES THE COMPANY PROPOSE TO ENACT THE RNA?

A. The Company proposes to set the benchmark distribution revenue levels by month for the peak period, October through March, and off-peak period, April through September, separately, based on the revenue requirement approved in the present proceeding (Columbia St. No. 3, pp. 32-33).

Q. IS THIS THE FIRST PROCEEDING IN WHICH THE COMPANY HAS PROPOSED TO ENACT THE RNA?

A. No. The Company has proposed to enact the RNA in several previous rate cases. Most recently, the Company proposed to enact the RNA in its rate case at Docket No. R-2020-3018835.

Q. DID THE COMPANY MAKE ANY CHANGES TO ITS PROPOSED RNA BETWEEN THE LAST PROCEEDING AND THE PRESENT PROCEEDING?

A. Functionally, no. The Company updated its data and proposed rates to align with the FPFTY in the present proceeding and added, on pages 28-32 of Columbia St. No. 11, a description of how "the proposed RNA aligns with the Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883."

Q. DO YOU RECOMMEND THAT THE RNA BE APPROVED?

A. No.

Q. WHY DO YOU RECOMMEND THAT THE RNA NOT BE APPROVED?

A. I recommend that the RNA not be approved for the following reasons. First, the Commission recently determined the RNA was unnecessary. Second, the policy statement cited by the Company does not allow Columbia to abandon the necessity to charge just and reasonable rates. Third, the use of the FPFTY already provides projected lower usage levels.

Q. WHAT DID THE COMMISSION DETERMINE REGARDING THE RNA IN COLUMBIA'S LAST BASE RATE CASE?

A. The Commission determined that the RNA, as presented in Columbia's last base rate case, was not needed and would not produce rates that are just, reasonable, and in the public interest. (Docket No. R-2020-3018835, pp. 264-265, Order entered February 19, 2021).

Q. DOES THE REFERENCE TO THE STATEMENTS OF POLICY IN THE ALTERNATIVE RATE MAKING DOCKET NO. M-2015-2518883 NEGATE THE OBLIGATION OF A COMPANY TO CHARGE RATES THAT ARE JUST, REASONABLE, AND IN THE PUBLIC INTEREST?

A. No. The Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883 does not negate the obligation of a Company to charge rates that are just and reasonable. Moreover, Columbia seeks to point to the 2015 Policy Statement as justification for the RNA but disregards the Commission's February 19, 2021 Order denying Columbia's RNA proposal.

Q. DOES THE USE OF THE FPFTY ALREADY INCLUDE PROJECTED ADJUSTMENTS FOR DECLINES IN USAGE?

A. Yes. Through Act 11 and the FPFTY, the Company is permitted to build into its revenue requirement an adjustment for revenue lost due to a decline in usage that is projected to occur up to a year after rates go into effect.

Q. HAS THE COMPANY DEMONSTRATED A NEED FOR SUCH REVENUE STABILIZATION IN THE PRESENT PROCEEDING?

A. No. As I stated above, the Company did not add any additional information or support that would cause the Commission to reverse its decision that the RNA does not provide rates that are just, reasonable, and in the public interest.

<u>PRESENT RATE REVENUE</u>

Q. WHAT IS THE COMPANY'S CLAIM FOR REVENUE UNDER PRESENT RATES IN THE FPFTY?

A. The Company's claim for revenue under present rates in the FPFTY is $661,206,723 (Columbia Ex. 103, Sch. 1, p. 18 of 18). This claim is comprised of $659,932,690 from total Company throughput and $1,274,033 from other operating revenues.

Q. DO YOU DISAGREE WITH ANY PART OF COLUMBIA'S CLAIM FOR OTHER OPERATING REVENUES?

A. Yes. Included in the overall claim for other operating revenues is a claim for negative $4,774 in miscellaneous revenue. This negative $4,774 in annual miscellaneous revenues is based on the actual miscellaneous revenues received in the HTY ended September 30, 2020. As shown in the Attachment to the Company's response to I&E-RS-5-D, attached as I&E Exhibit No. 3, Schedule 1, the negative revenue amount is due to the negative $55,314.27 amount in August of 2020. Based on the rest of the miscellaneous service revenue amounts shown on I&E Exhibit No. 3, Schedule 1, August 2020 appears to be an anomalous event. It is not reasonable to project a continued negative revenue amount in the FPFTY based on one anomalous month of data in the HTY.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO MISCELLANEOUS SERVICE REVENUE UNDER PRESENT RATES IN THE FPFTY?

A. Yes. I am recommending that the Company's present rate revenue claim for miscellaneous service revenue be increased by $59,635 from negative $4,774 to $54,861.

Q. HOW DID YOU DETERMINE THE RECOMMENDED $59,635 INCREASE TO MISCELLANEOUS SERVICE REVENUE?

A. As I stated above, Attachment A to the Company's response to I&E-RS-5 (I&E Exhibit No. 3, Sch. 1) shows that the actual miscellaneous service revenue amount for August 2020 was negative $55,314. As this amount appears to be an outlier compared to the monthly amounts for the months from December 2016 through April 2021 and is therefore unlikely to continue into the FPFTY. Therefore, for the purposes of projecting miscellaneous service revenues in the FPFTY, I replaced the negative $55,635 miscellaneous service revenue amount in August 2020 with a positive $4,321 amount. The $4,321 miscellaneous service revenue amount represents an average of the three amounts received by the Company in August 2017, 2018, and 2019 (($14,682 - $5,256 + $3,536) / 3 = $4,321) (I&E Ex. No. 3, Sch. 2). Using a three-year average of August amounts for miscellaneous service revenues is reasonable to project miscellaneous service revenues for the FPFTY because it uses data from the same month and is, therefore, a more "apples to apples" comparison, and is recent enough that the data is not stale but still contains enough data points to smooth out any fluctuations.

Q. WHAT EFFECT DOES YOUR RECOMMENDATION HAVE ON THE COMPANY'S OVERALL PRESENT RATE REVENUE CLAIM?

A. As shown on I&E Exhibit No. 3, Schedule 3, my recommendation increases the Company's present rate revenue claim by the same $59,635 from $661,206,723 to $661,266,358.

COST OF SERVICE

Q. WHAT IS AN ALLOCATED COST OF SERVICE ("ACOS") STUDY?

A. A utility provides service to a defined set of customer classes that are different in terms of demand and usage patterns. An ACOS allocates or assigns a utility's revenue requirement based on those service differences. In other words, an ACOS is a formalized analysis of costs that attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of such a study can be utilized to determine the relative cost of service for each class and help determine the individual class revenue requirements and, to the extent a particular class is above or below the system average rate of return, show the additional revenues each class receives or conversely the additional revenues that each class contributes to the Company's overall revenues. In addition to the relative provision of revenues, a relative rate of return is also provided, which shows how the rate of return for each class compares to the system average rate of return.

Q. WHAT ARE RATE OF RETURN AND RELATIVE RATE OF RETURN?

A. The rate of return is the Commission authorized return on rate base that is determined in a base rate proceeding. A relative rate of return indicates how the rate of return of each customer class compares to the system average rate of return. In general, a relative rate of return that provides revenue equal to its cost to serve would have a relative rate of return equal to 1.0.

Q. DID THE COMPANY PROVIDE AN ACOS STUDY IN THIS PROCEEDING?

A. Yes. The Company performed and provided three ACOS studies in its filing sponsored by Columbia witness Chad Notestone as he described on page 2 of Columbia Statement No. 11. The first is a customer-demand ACOS study (Columbia Exhibit No. 111, Schedule 1), the second is a peak and average ACOS study (Columbia Exhibit No. 111, Schedule 2), and the third ACOS study is an average of the customer-demand studies and the peak and average studies (Columbia Exhibit No. 111, Schedule 3).

Q. WHAT IS THE LARGEST CAPITAL COST FOR COLUMBIA?

A. On page 9 of Columbia Statement No. 11, Mr. Notestone states that "[m]ains and services account for the majority of the Company's gross plant investment and distribution O&M expenses."

Q. WHAT IS THE MAIN DIFFERENCE BETWEEN THE CUSTOMER-DEMAND AND THE PEAK AND AVERAGE ACOS STUDIES?

A. The difference between the customer-demand ACOS and the peak and average ACOS studies presented by Mr. Notestone in Company Exhibit No. 111 is in the way that each study allocates the costs of mains. Consequently, the two ACOS studies yield different relative rates of return for each rate class.

The customer-demand methodology classifies distribution mains as partially customer related and partially demand related. The customer portion of mains is then allocated to the various customer classes based on the total number of customers, while the demand portion of mains is allocated to classes based on peak day contributions or demand. This methodology was rejected by the Commission in the Company's last base rate case (Docket No. R-2020-3018835, pp. 217-218, Order entered February 19, 2021).

The peak and average ACOS, however, allocates distribution mains to classes based partially on contributions to peak day demand and partially on annual consumption (average demand). This methodology was accepted by the Commission in the Company's last base rate case (Docket No. R-2020-3018835, p. 218, Order entered February 19, 2021).

Q. WHICH OF THE THREE ACOS STUDIES SPONSORED BY MR. NOTESTONE DID THE COMPANY UTILIZE TO ALLOCATE THE PROPOSED REVENUE INCREASES?

A. Consistent with the Commission's Order from the last base rate case, discussed above, the Company utilized the second ACOS study sponsored by Mr. Notestone, which is the peak and average study, presented on Columbia Exhibit No. 111, Schedule No. 2 to allocate the proposed revenue increases (Columbia St. No. 11, p. 3).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED USE OF THE PEAK AND AVERAGE METHODOLOGY TO ALLOCATE THE REVENUE INCREASES AMONG THE DIFFERENT CUSTOMER CLASSES IN THIS PROCEEDING?

A. Yes.

Q. DID THE COMPANY ALSO ELECT TO SHOW THE FLEX RATE CUSTOMERS UNDER THEIR OWN RATE CLASS IN THE COST OF SERVICE STUDY?

A. Yes. This is important so that the Commission can determine the cost to provide service to the flex and non-flex customers and the subsidy being provided by tariff rate customers. With this information, the Commission can establish fair and reasonable rates for all other non-flex customers in non-flex classes.

Q. WHAT DO YOU RECOMMEND CONCERNING FUTURE COLUMBIA BASE RATE CASES?

A. I recommend two things in future base rate cases. First, I recommend the Company continue to utilize the peak and average cost of service study to establish rates. Second, I recommend that the Company continue to classify flex rate customers as a separate class in future cost of service studies. The rationale for both of these recommendations is described above.

CUSTOMER COST ANALYSIS

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is a part of a COSS that is used to determine the appropriate fixed customer charges for the various classes and meter sizes. It includes customer costs only.

Q. WHY IS IT NECESSARY TO PERFORM A CUSTOMER COST ANALYSIS?

A. A fixed customer charge represents the revenue that the Company is guaranteed to receive each month, regardless of the level of usage. As acknowledged in the seventh edition of the American Water Works Association M1 Manual, there is a tradeoff between revenue stability from a high customer charge, and affordability and conservation from a low customer charge and higher usage rates.[2]

Q. WHAT IS A DIRECT CUSTOMER COST?

A. A direct customer cost is a cost that changes with the increase or decrease of a single customer.

Q. WHAT IS AN INDIRECT CUSTOMER COST?

A. An indirect customer cost is a customer related cost that does not change with the increase or decrease of a single customer. The Commission has allowed, in past instances, certain indirect customer costs to be included in a customer cost analysis and thus recovered in a customer charge. As an example, in previous cases, the Commission has allowed the indirect cost of Employee Pension and Benefits.

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[2] AWWA Manual of Water Supply Practices M1 Principles of Water Rates, Fees, Charges, Seventh Edition. pp. 154-155.

Q. DID COLUMBIA PREPARE A CUSTOMER COST ANALYSIS TO SUPPORT THE PROPOSED CUSTOMER CHARGE INCREASES IN THIS PROCEEDING?

A. Yes. The Company prepared two customer cost analyses presented in Columbia Exhibit No. 111, Schedule 1, pages 16 and 25. The first of the Company's customer cost analyses allocates a portion of the cost of mains to customers. The second of the Company's customer cost analyses does not allocate any portion of the cost of mains to customers. The results of each customer cost analysis are presented in the following table:

Customer Class	Including Mains (Columbia Ex. No. 111, Sch. 1, p. 16, line 41)	Excluding Mains (Columbia Ex. No. 111, Sch. 1, p. 25, line 37)
RSS/RDS	$62.23	$24.23
SGS/DS-1	$69.08	$27.03
SGS/DS-2	$126.12	$46.27
SDS/LGSS	$534.11	$212.97
LDS/LGSS	$2,641.14	$1,055.67
MLDS	$821.92	$702.67
FLEX	$6,338.12	$1,666.82

Q. HOW DID COLUMBIA DETERMINE THE FIXED MONTHLY COSTS BY CUSTOMER CLASS ABOVE?

A. According to Columbia witness Notestone, the Company designed its rates to include the principles of efficiency, simplicity, continuity, fairness, and earnings stability (Columbia St. No. 11, p. 15).

Q. DO YOU BELIEVE THAT THE COMPANY'S CUSTOMER COST ANALYSIS THAT INCLUDES THE COST OF MAINS SHOULD BE CONSIDERED?

A. No. The Commission has established in Columbia's previous case that mains are not properly included as a customer cost (Docket No. R-2020-3018835, p. 218, Order entered February 19, 2021). Therefore, the Company's customer cost analysis that includes the cost of mains is invalid.

CUSTOMER CHARGES

Q. WHAT CUSTOMER CHARGES IS THE COMPANY PROPOSING FOR EACH RATE CLASS?

A. The customer charges for each rate class that received a proposed increase is shown in the table below. (Columbia No. 103, Sch. No. 8, pp. 5-9).

Rate Schedule (Therms, annually)	Present Rate	Change	Proposed Rate	Percent Increase
RS, RDS, RCC				
All Usage	$16.75	$2.58	$19.33	15.4%
SGSS1, SCD1, SGDS1				
≤6,440	$26.00	$5.50	$31.50	21.2%
SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$55.00	$11.00	$66.00	20.0%
SDS/LGSS				
>64,400 to ≤110,000	$265.00	$70.00	$335.00	26.4%
>110,000 to ≤540,000	$874.00	$230.00	$1,104.00	26.3%
LDS				
>540,000 to ≤1,074,000	$2,247.00	$672.00	$2,919.00	29.9%
>1,074,000 to ≤3,400,000	$3,495.00	$1,045.00	$4,540.00	29.9%
>3,400,000 to ≤7,500,000	$6,740.00	$2,015.00	$8,755.00	29.9%
>7,500,000	$9,985.00	$2,986.00	$12,971.00	29.9%

Q. ARE YOU RECOMMENDING ADJUSTMENTS TO ANY OF THE COMPANY'S PROPOSED CUSTOMER CHARGES?

A. Yes. Based on the customer cost analysis that does not include the cost of mains, as described above, the customer charges for the SGS1, SGS2, and SDS/LGSS classes are too high. I am not recommending an adjustment to the proposed customer charges for the LDS customers because higher usage customers generally favor a higher fixed charge and lower usage charges. I am also not recommending an adjustment to the residential customer charge because it is consistent with the customer cost analysis.

Q. WHAT CUSTOMER CHARGES ARE YOU RECOMMENDING FOR THE SGS1, SGS2, AND SDS/LGSS CLASSES?

A. I am recommending the customer charges for the SGS1, SGS2, and SDS/LGSS classes be adjusted to be consistent with the customer cost analysis as follows:

Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Present Rate	Company Proposed Rate	Change	I&E Proposed Rate
	RS, RDS, RCC				
All Usage	$24.23	$16.75	$19.33	$0.00	$19.33
	SGSS1, SCD1, SGDS1				
≤6,440	$27.03	$26.00	$31.50	($5.50)	$26.00
	SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$46.27	$55.00	$66.00	($11.00)	$55.00
	SDS/LGSS				
>64,400 to ≤110,000	$212.97	$265.00	$335.00	($70.00)	$265.00
>110,000 to ≤540,000	$1,055.67	$874.00	$1,104.00	($49.00)	$1,055.00

<u>SCALE BACK OF RATES</u>

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommend that the first $36,000,000 reduction be applied to the RSS/RSD class (I&E Ex, No. 3, Sch. 4, p. 1, line 13). The next $26,700,000 reduction should be applied to the various classes as shown on I&E Exhibit No. 3. Sch. 5, p. 1, line 14). Any scale back between $36,000,000 and $62,700,000 ($36,000,000 + $26,700,000) should be interpolated between the revenue levels shown on I&E Exhibit No. 3. Sch. 5. p. 1, lines 13 and 14. Any further scale back directed by the Commission is described below.

Q. WHY DO YOU RECOMMEND THE FIRST $36 MILLION OF A SCALE BACK BE APPLIED TO THE RSS/RDS CLASS?

A. Under proposed rates, the relative rate of return for the RSS/RDS class is 1.25, well above the system average. Reducing the increase by $36 million brings the relative rate of return down to. 1.20, equal to the 1.20 relative rate of return of the SGS/GS-1 class at this revenue level (I&E Ex. No. 3, Sch. 4, p. 2, line 14).

Q. HOW DID YOU DETERMINE THE $26.7 MILLION SECOND STEP?

A. I adjusted the revenue downward so that the relative rate of return for the RSS/RDS. SGS/GS-1, SGS/GS-2 and LDS/LGSS classes are all 1.19 (I&E Ex. No. 3, Sch. 5, p. 2, line 14). As described above, equal rates of return indicate that each class in contributing proportionally to the revenue shortfall causes by the other classes that contribute less than the cost to serve those classes.

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND IF THE COMMISSION GRANTS A SCALEBACK GREATER THAN $62.7 MILLION?

A. If the Commission grants a decrease greater than $62.7 million, I recommend the 71% of the reduction be applied to the RSS/RSD class, that 10% be applied to the SGS/GS-1 class, that 11% be applied to the SGS/GS-2 class and that 8% be applied to the SDS/LGSS class (I&E Exhibit No. 3, Sch. 6, p. 1, lines 15-16). This recommendation excludes the LDS/LGSS, MLDS and Flex rate classes.

Q. WHY DO YOU MAKE THIS SPECIFIC RECOMMENDATION?

A. Any further scale back allocated to these classes based upon these percentages will maintain the relative rates of return for the classes being scaled back (I&E Ex. No. 3, Sch. 6, p. 2, line 14). The LDS/LGSS class rates should not be scaled back because the relative rate of return under proposed rates is so low. The MLDS class should not be scaled back because the Company did not propose any increase for this class. The Flex class should not be scaled back because these customers pay negotiated rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ETHAN H. CLINE

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present
Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008
Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008
J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007
CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL
- Attended Society of Depreciation Professionals Annual Conference and Training

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. PAWC Clarion Wastewater Operations, Docket No. R-2010-2166208
6. PAWC Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Columbia Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition,
    Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172
37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934
40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209

44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638
51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296
57. Columbia Gas of Pennsylvania, Inc., Docket No. R-2018-2647577
58. Duquesne Light Company, Docket No. R-2018-3000124
59. Suez Water Pennsylvania, Inc., Docket No. R-2018-3000834
60. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the Township of Sadsbury, Docket No. A-2018-3002437
61. The York Water Company, Docket No. R-2018-3000006
62. Application of SUEZ Water Pennsylvania, Inc. Acquisition of the Water and Wastewater Assets of Mahoning Township, Docket Nos. A-2018-3003517 and A-2018-3003519
63. Pittsburgh Water and Sewer Authority, Docket Nos. R-2018-3002645 and R-2018-3002647
64. Joint Application of Aqua America, Inc. et al., Acquisition of Peoples Natural Gas Company LLC, et al., Docket Nos. A-2018-3006061, A-2018-3006062, and A-2018-3006063
65. Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority, Docket Nos. M-2018-2640802 and M-2018-2640803
66. Philadelphia Gas Works 1307(f), Docket No. R-2019-3007636
67. People Natural Gas Company, LLC, Docket No. R-2018-3006818
68. Application of Pennsylvania American Water Company Acquisition of the Steelton Borough Authority, Docket No. A-2019-3006880
69. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the Township of Cheltenham, Docket No. A-2019-3006880
70. Philadelphia Gas Works, Docket No. R-2019-3009016
71. Wellsboro Electric Company, Docket No. R-2019-3008208
72. Valley Energy, Inc., Docket No. R-2019-3008209
73. Citizens' Electric Company of Lewisburg, Pa, Docket Non. R-2019-3008212
74. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the East Norriton Township, Docket No. A-2019-3009052
75. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2020-3017850
76. Peoples Gas Company, LLC 1307(f), Docket No. R-2020-3017846
77. Philadelphia Gas Works, Docket No. R-2020-3017206
78. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 et al.
79. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835

80. Pennsylvania America Water Company, Docket Nos. R-2020-3019369 and R-2020-3019371
81. PECO Energy Company – Gas Division, Docket No. R-2020-3019829
82. PGW 1307(f), Docket No. R-2021-3023970
83. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2021-3023965
84. Peoples Gas Company, LLC 1307(f), Docket No. R-2021-3023967
85. UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618

I&E Exhibit No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Exhibit to Accompany

the

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Revenue Normalization Adjustment
Present Rate Revenues
Cost of Service Study
Scale Back of Rates

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RS

Question No. I & E RS-005-D:

Reference Other Operating Revenue shown on Company Exhibit No. 2, Schedule No. 5, page 2. Please provide the following with supporting documentation:

A. A monthly breakdown of the $502,806 of Forfeited Discounts (Account 487) for the test year ended November 30, 2020;

B. A monthly breakdown of the $1,080,703 of Forfeited Discounts (Account 487) for the test year ended November 30, 2019;

C. The actual monthly Forfeited Discounts (Account 487) collected by the Company from December 1, 2016, until the most recent month available;

D. A monthly breakdown of the negative $4,774 of Miscellaneous Service Revenue (Account 488) for the test year ended November 30, 2020;

E. A monthly breakdown of the $225,882 of Miscellaneous Service Revenue (Account 488) for the test year ended November 30, 2019;

F. The actual monthly Miscellaneous Service Revenue (Account 488) collected by the Company from December 1, 2016, until the most recent month available;

G. A monthly breakdown of the $124,223,682 of Transportation of Gas (Account 489) for the test year ended November 30, 2020;

H. A monthly breakdown of the $131,264,829 of Transportation of Gas (Account 489) for the test year ended November 30, 2019;

I. The actual monthly Transportation of Gas (Account 489) revenue collected by the Company from December 1, 2015, until the most recent month available;

J. A monthly breakdown of the $0 of Rent from Gas Department Revenue (Account 493) for the test year ended November 30, 2020;

K. A monthly breakdown of the $1,213 of Rent from Gas Department Revenue (Account 493) for the test year ended November 30, 2019;

L. The actual monthly Rent from Gas Department Revenue (Account 493) revenue collected by the Company from December 1, 2015, until the most recent month available;

M. A monthly breakdown of the negative $210,798 Other Gas Department Revenue (Account 495) for the test year ended November 30, 2020;

N. A monthly breakdown of the $3,334,922 Other Gas Department Revenue (Account 495) for the test year ended November 30, 2019; and

O. The actual monthly Other Gas Department revenues (Account 495) collected by the Company from December 1, 2016, until the most recent month available.

Response:

Please see I&E RS-5-D Attachment A.

Columbia Gas of Pennsylvania, Inc.
Other Operating Revenues by Type
December 2016 - April 2021

FORFEITED DISCOUNTS - 487

	December	January	February	March	April	May	June	July	August	September	October	November	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
2016-2017	$ 65,477.11	$ 116,084.64	$ 172,263.45	$ 159,464.27	$ 127,671.96	$ 93,639.41	$ 77,084.48	$ 122,403.07	$ 26,391.61	$ 35,741.29	$ 44,712.26	$ 41,160.35	$ 1,082,093.90
2017-2018	$ 66,132.39	$ 127,412.17	$ 201,583.71	$ 185,321.69	$ 85,962.55	$ 114,080.69	$ 93,199.65	$ 64,861.69	$ 52,832.23	$ 48,864.29	$ 45,755.04	$ 44,916.46	$ 1,130,922.56
2018-2019	$ 75,923.40	$ 141,788.72	$ 181,420.58	$ 158,565.01	$ 138,228.67	$ 104,830.48	$ 22,389.94	$ 64,078.27	$ 56,852.80	$ 49,671.56	$ 44,227.38	$ 42,725.90	$ 1,080,702.71
2019-2020	$ 70,869.90	$ 134,164.65	$ 161,894.42	$ 75,437.84	$ (37,189.99)	$ (872.50)	$ 65,626.83	$ (875.56)	$ 6,219.11	$ 22,618.48	$ (9,618.68)	$ 14,531.35	$ 502,805.85
2020-2021	$ 19,891.04	$ 64,734.40	$ 73,739.24	$ 77,364.55	$ 44,879.00								$ 280,608.23

MISC. SERVICE REVENUE - 488

	December	January	February	March	April	May	June	July	August	September	October	November	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
2016-2017	$ 4,224.70	$ 2,023.10	$ 11,630.30	$ (441.77)	$ 10,471.38	$ 11,897.07	$ 7,609.51	$ 14,741.71	$ 14,682.24	$ 12,964.74	$ 6,256.75	$ 9,856.68	$ 105,916.41
2017-2018	$ 18,596.94	$ 143.81	$ 2,337.15	$ 6,865.06	$ 6,669.69	$ 18,574.00	$ 14,052.25	$ 18,104.32	$ (5,256.35)	$ 18,351.56	$ 8,535.03	$ 10,673.35	$ 117,646.81
2018-2019	$ 3,841.88	$ 94,994.53	$ 5,250.51	$ 6,053.27	$ 12,482.46	$ 12,607.99	$ 13,098.61	$ 25,880.49	$ 3,535.92	$ 12,985.05	$ 18,731.25	$ 16,420.00	$ 225,881.96
2019-2020	$ 17,428.93	$ 2,285.21	$ 7,701.20	$ 6,712.00	$ 4,556.00	$ 5,057.60	$ 1,015.15	$ 2,504.35	$ (55,314.27)	$ 16,343.66	$ (14,751.66)	$ 1,688.00	$ (4,773.83)
2020-2021	$ 1,932.00	$ 6,421.10	$ 2,631.24	$ 1,566.38	$ 1,178.35								$ 13,729.07

TRANSPORTATION OF GAS - 489

	December	January	February	March	April	May	June	July	August	September	October	November	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
2015												$ 11,414,906.25	$ 11,414,906.25
2016-2017	$ 16,315,183.09	$ 17,960,991.56	$ 16,707,185.87	$ 16,514,644.77	$ 8,679,897.66	$ 7,653,680.99	$ 5,288,760.50	$ 5,224,763.23	$ 5,224,622.65	$ 5,586,200.11	$ 7,295,167.69	$ 12,684,349.75	$ 125,135,447.87
2017-2018	$ 17,948,525.93	$ 19,720,641.31	$ 16,574,761.52	$ 15,065,370.92	$ 10,097,204.76	$ 6,069,488.41	$ 5,169,711.38	$ 4,563,067.77	$ 4,634,644.99	$ 4,917,129.25	$ 7,431,477.46	$ 13,125,682.96	$ 125,317,706.66
2018-2019	$ 17,339,350.51	$ 19,999,019.83	$ 17,366,539.97	$ 16,647,414.08	$ 10,728,441.97	$ 5,932,643.87	$ 5,394,769.81	$ 5,489,798.64	$ 5,263,798.76	$ 5,290,646.76	$ 7,989,705.21	$ 13,822,699.20	$ 131,264,828.61
2019-2020	$ 16,947,089.01	$ 18,704,949.83	$ 19,830,378.20	$ 12,301,222.75	$ 9,585,700.06	$ 6,261,191.41	$ 5,017,697.76	$ 5,215,021.39	$ 5,228,352.37	$ 5,308,234.57	$ 8,590,644.91	$ 11,233,199.82	$ 124,223,682.08
2020-2021	$ 19,803,854.14	$ 19,327,156.92	$ 19,105,453.93	$ 18,465,533.09	$ 11,158,858.36								

Rent from Gas Property - 493

	December	January	February	March	April	May	June	July	August	September	October	November	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
2015												14259	14259
2016-2017	$ 8,327.50	$ 435.50	$ (213.00)	$ 125.00	$ 122.50	$ 120.00	$ 120.00	$ 115.00	$ 112.50	$ 110.00	$ 110.00	$ 115.00	$ 9,600.00
2017-2018	$ 120.00	$ 115.00	$ 115.00	$ 115.00	$ 110.00	$ 110.00	$ 110.00	$ 110.00	$ 112.50	$ 112.50	$ 110.00	$ 107.50	$ 1,347.50
2018-2019	$ 110.00	$ 110.00	$ 110.00	$ 110.00	$ 105.00	$ 100.00	$ 97.50	$ 95.00	$ 95.00	$ 90.00	$ 95.00	$ 95.00	$ 1,212.50
2019-2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020-2021	$ -	$ -	$ -	$ -	$ -								$ -

OTHER GAS DEPT. REVENUE - 495

	December	January	February	March	April	May	June	July	August	September	October	November	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
2016-2017	$ 12,330,079.27	$ 83,117.16	$ (7,404,029.47)	$ (2,807,499.18)	$ (13,525,975.45)	$ (2,052,872.39)	$ (2,494,088.30)	$ 192,126.39	$ 2,975,176.67	$ 1,854,403.31	$ 8,290,624.80	$ 15,841,409.64	$ 13,282,472.45
2017-2018	$ 13,739,042.73	$ (4,799,042.10)	$ (11,498,478.73)	$ 874,622.45	$ (13,273,699.29)	$ (7,930,241.74)	$ 848,323.86	$ 307,853.24	$ 1,572,797.52	$ 1,110,445.26	$ 10,443,380.42	$ 15,251,254.58	$ 6,646,258.20
2018-2019	$ 10,090,931.65	$ 9,858,830.71	$ (13,280,267.29)	$ (7,668,757.89)	$ (13,650,877.45)	$ (6,023,012.22)	$ (1,778,603.71)	$ 162,300.46	$ 339,375.38	$ 500,331.13	$ 8,483,476.59	$ 16,301,194.58	$ 3,334,921.94
2019-2020	$ 6,605,019.27	$ (8,731,114.05)	$ 5,358,532.02	$ (9,471,689.81)	$ (5,719,086.35)	$ (6,208,311.21)	$ (3,750,902.90)	$ 80,602.20	$ 298,920.02	$ 1,837,849.70	$ 7,286,128.01	$ 12,203,255.26	$ (210,797.84)
2020-2021	$ 13,469,189.65	$ 929,451.65	$ (4,233,344.09)	$ (9,288,123.13)	$ (10,410,887.16)								$ (9,533,713.08)

I&E Exhibit No. 3
Schedule 2

Columbia Gas of Pennsylvania, Inc.
Other Operating Revenues by Type
December 2016 - April 2021
I&E Adjustment to Miscellaneous Revenue

MISC. SERVICE REVENUE - 488

	December	January	February	March	April	May	June	July	August	September	October	November	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
2016-2017	$ 4,224.70	$ 2,023.10	$ 11,630.30	$ (441.77)	$ 10,471.38	$ 11,897.07	$ 7,609.51	$ 14,741.71	$ 14,682.24	$ 12,964.74	$ 6,256.75	$ 9,856.68	$ 105,916.41
2017-2018	$ 18,596.94	$ 143.81	$ 2,337.15	$ 6,865.06	$ 6,669.69	$ 18,574.00	$ 14,052.25	$ 18,104.32	$ (5,256.35)	$ 18,351.56	$ 8,535.03	$ 10,673.35	$ 117,646.81
2018-2019	$ 3,841.88	$ 94,994.53	$ 5,250.51	$ 6,053.27	$ 12,482.46	$ 12,607.99	$ 13,098.61	$ 25,880.49	$ 3,535.92	$ 12,985.05	$ 18,731.25	$ 16,420.00	$ 225,881.96
2019-2020	$ 17,428.93	$ 2,285.21	$ 7,701.20	$ 6,712.00	$ 4,556.00	$ 5,057.60	$ 1,015.15	$ 2,504.35	**$ 4,320.60**	$ 16,343.66	$ (14,751.66)	$ 1,688.00	$ 54,861.04
2020-2021	$ 1,932.00	$ 6,421.10	$ 2,631.24	$ 1,566.38	$ 1,178.35								$ 13,729.07

I&E Exhibit No. 3
Schedule 3

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended December 31, 2022

Line No.	Description	Bills (1) (Ex 103, Sch 2)	Volumes (2) DTH (Ex 103, Sch 3)	Base Rate (3) $/DTH	Company Revenue (4) $	Adjustment $	I&E Revenue $
1	**Total Company Throughput**	5,389,350	81,968,992.7		659,932,690	0	659,932,690
2	**Other Operating Revenue**						
3	487 - Forfeited Discounts				1,262,451	0	1,262,451
4	488 - Miscellaneous Service Revenues				(4,774)	59,635	54,861
5	493 - Rent from Gas Property				0	0	0
6	495 - Prior Yr. Rate Refund - Net.				0	0	0
7	495 - Off System Sales				0	0	0
8	495 - Other Gas Revenues - Other				16,356	0	16,356
9	496 - Provision For Rate Refunds				0	0	0
10	**Total Other Operating Revenue**				1,274,033	59,635	1,333,668
11	**Total Company Revenue**				661,206,723	59,635	661,266,358

Columbia Gas of Pennsylvania
REVENUE SUMMARY
R-2021-3024296
FIRST $36,000,000 Scale Back

LINE NO.	Tariff Revenue (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	Sales Customers		$576,669,411	$455,042,529	$48,942,578	$38,792,041	$8,494,617	$25,397,646		
2	Choice Customers		$127,445,589	$69,719,497	$15,663,091	$12,909,148	$29,153,853			
3	Cap Customers		$25,445,115	$25,445,115						
4	Choice Customers		$23,726,715		$2,148,327	$21,578,388	-$355,590	$355,590	-	
5	MDLS-1		$53,292						$53,292	
6	MDLS-2		$1,035,292						$1,035,292	
7	Negotiated		$3,647,747						$240,703	$3,407,044
8	TOTAL Tariff REVENUE		$758,023,161	$550,207,141	$66,753,996	$73,279,577	$37,292,880	$25,753,236	$1,329,287	$3,407,044
	Other Revenue		**TOTAL**	**RSS/RDS**	**SGS/DS-1**	**SGS/DS-2**	**SDS/LGSS**	**LDS/LGSS**	**MLDS**	**FLEX**
9	Forfeited Discounts		$1,450,097	$1,058,397	$128,783	$141,718	$57,380	$53,393	$2,929	$7,497
10	Miscellaneous Revenue		-$4,773	-$4,371	-$335	-$61	-$5	-$1	$0	$0
11	Other		$16,357	$14,997	$1,147	$209	$3	$0	$1	$0
12	Total Other		$1,461,681	$1,069,023	$129,595	$141,866	$57,378	$53,392	$2,930	$7,497
13	First Step Scale Back		-$36,000,000	-$36,000,000	$0	$0	$0	$0	$0	$0
14	TOTAL REVENUE		$723,484,842	$515,276,164	$66,883,591	$73,421,443	$37,350,258	$25,806,628	$1,332,217	$3,414,541
15	INCREASE		$62,278,114	$31,763,624	$8,464,410	$9,131,299	$7,007,364	$5,895,248	$379	$15,790

Columbia Gas of Pennsylvania
Rate of Return under First 36 Million Scale Back
R-2021-3024296

Allocated Cost of Service Study
Peak and Average

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	TOTAL REVENUE [PAGE 6]		$723,484,842	$515,276,164	$66,883,591	$73,421,443	$37,350,258	$25,806,628	$1,332,217	$3,414,541
2	PRODUCTS PURCHASED [PAGE 7]		$161,368,307	$119,615,901	$17,998,184	$19,709,532	$3,655,831	$168,466	$220,393	$0
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		$225,828,345	$162,866,636	$16,162,049	$15,609,339	$10,097,084	$11,653,755	$26,299	$9,413,183
4	DEPRECIATION & AMORTIZATION [PAGE 5]		$109,970,328	$69,639,097	$9,225,419	$10,057,955	$6,623,106	$7,830,220	$29,419	$6,565,112
5	TAXES OTHER THAN INCOME [PAGE 9]		$3,715,938	$2,483,420	$310,109	$304,027	$197,500	$230,573	$249	$190,060
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		$500,882,918	$354,605,054	$43,695,761	$45,680,853	$20,573,521	$19,883,014	$276,360	$16,168,355
7	OPERATING INCOME BEFORE TAXES		$222,601,924	$160,671,110	$23,187,830	$27,740,590	$16,776,737	$5,923,614	$1,055,857	-$12,753,814
8	INCOME TAXES		$37,810,519	$25,638,489	$4,510,058	$6,451,791	$4,019,649	$1,045,230	$300,445	($4,155,142)
9	INVESTMENT TAX CREDIT	12	($243,013)	($149,834)	-$20,520	-$23,392	-$15,439	-$18,348	-$49	-$15,431
10	NET INCOME TAXES		$37,567,506	$25,488,655	$4,489,538	$6,428,399	$4,004,210	$1,026,882	$300,396	-$4,170,573
11	OPERATING INCOME		$185,034,418	$135,182,455	$18,698,292	$21,312,191	$12,772,527	$4,896,732	$755,461	-$8,583,241
12	RATE BASE [PAGE 10]		$2,673,012,065	$1,632,611,139	$224,690,377	$263,041,870	$173,378,146	$205,632,659	$479,273	$173,178,601
13	RATE OF RETURN EARNED ON RATE BASE		6.922%	8.280%	8.322%	8.102%	7.367%	2.381%	157.627%	-4.956%
14	UNITIZED RETURN		1.00	1.20	1.20	1.17	1.06	0.34	22.77	(0.72)
15	Percent Increase		9.42%	6.6%	14.5%	14.2%	23.1%	29.6%	0.0%	0.5%

Columbia Gas of Pennsylvania
REVENUE SUMMARY
R-2021-3024296
$52.7 Million Scale Back

LINE NO.	Tariff Revenue (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	Sales Customers		$576,669,411	$455,042,529	$48,942,578	$38,792,041	$8,494,617	$25,397,646		
2	Choice Customers		$127,445,589	$69,719,497	$15,663,091	$12,909,148	$29,153,853			
3	Cap Customers		$25,445,115	$25,445,115						
4	Choice Customers		$23,726,715		$2,148,327	$21,578,388	-$355,590	$355,590	-	
5	MDLS-1		$53,292						$53,292	
6	MDLS-2		$1,035,292						$1,035,292	
7	Negotiated		$3,647,747						$240,703	$3,407,044
8	TOTAL Tariff REVENUE		$758,023,161	$550,207,141	$66,753,996	$73,279,577	$37,292,880	$25,753,236	$1,329,287	$3,407,044
	Other Revenue		**TOTAL**	**RSS/RDS**	**SGS/DS-1**	**SGS/DS-2**	**SDS/LGSS**	**LDS/LGSS**	**MLDS**	**FLEX**
9	Forfeited Discounts		$1,450,097	$1,058,397	$128,783	$141,718	$57,380	$53,393	$2,929	$7,497
10	Miscellaneous Revenue		-$4,773	-$4,371	-$335	-$61	-$5	-$1	$0	$0
11	Other		$16,357	$14,997	$1,147	$209	$3	$0	$1	$0
12	Total Other		$1,461,681	$1,069,023	$129,595	$141,866	$57,378	$53,392	$2,930	$7,497
13	First Step Scale Back		-$36,000,000	-$36,000,000	$0	$0	$0	$0	$0	$0
14	Second Step Scale Back		-$26,700,000	-$21,000,000	-$3,000,000	-$2,700,000	$0	$0	$0	$0
15	TOTAL REVENUE		$696,784,842	$494,276,164	$63,883,591	$70,721,443	$37,350,258	$25,806,628	$1,332,217	$3,414,541
16	INCREASE		$35,578,114	$10,763,624	$5,464,410	$6,431,299	$7,007,364	$5,895,248	$379	$15,790

Columbia Gas of Pennsylvania
Rate of Return under $52.7 Milllion Scale Back
R-2021-3024296

Allocated Cost of Service Study
Peak and Average

111, Schedule 2
Page 1 of 13
Winess C.E. Notestone

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	TOTAL REVENUE [PAGE 6]		$696,784,842	$494,276,164	$63,883,591	$70,721,443	$37,350,258	$25,806,628	$1,332,217	$3,414,541
2	PRODUCTS PURCHASED [PAGE 7]		$161,368,307	$119,615,901	$17,998,184	$19,709,532	$3,655,831	$168,466	$220,393	$0
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		$225,828,345	$162,866,636	$16,162,049	$15,609,339	$10,097,084	$11,653,755	$26,299	$9,413,183
4	DEPRECIATION & AMORTIZATION [PAGE 5]		$109,970,328	$69,639,097	$9,225,419	$10,057,955	$6,623,106	$7,830,220	$29,419	$6,565,112
5	TAXES OTHER THAN INCOME [PAGE 9]		$3,715,938	$2,483,420	$310,109	$304,027	$197,500	$230,573	$249	$190,060
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		$500,882,918	$354,605,054	$43,695,761	$45,680,853	$20,573,521	$19,883,014	$276,360	$16,168,355
7	OPERATING INCOME BEFORE TAXES		$195,901,924	$139,671,110	$20,187,830	$25,040,590	$16,776,737	$5,923,614	$1,055,857	-$12,753,814
8	INCOME TAXES		$30,096,328	$19,571,148	$3,643,295	$5,671,704	$4,019,649	$1,045,230	$300,445	($4,155,142)
9	INVESTMENT TAX CREDIT	12	($243,013)	($149,834)	-$20,520	-$23,392	-$15,439	-$18,348	-$49	-$15,431
10	NET INCOME TAXES		$29,853,315	$19,421,314	$3,622,775	$5,648,312	$4,004,210	$1,026,882	$300,396	-$4,170,573
11	OPERATING INCOME		$166,048,609	$120,249,796	$16,565,055	$19,392,278	$12,772,527	$4,896,732	$755,461	-$8,583,241
12	RATE BASE [PAGE 10]		$2,673,012,065	$1,632,611,139	$224,690,377	$263,041,870	$173,378,146	$205,632,659	$479,273	$173,178,601
13	RATE OF RETURN EARNED ON RATE BASE		6.212%	7.365%	7.372%	7.372%	7.367%	2.381%	157.627%	-4.956%
14	UNITIZED RETURN		1.00	1.19	1.19	1.19	1.19	0.38	25.37	(0.80)
15	Percent Increase		5.38%	2.2%	9.4%	10.0%	23.1%	29.6%	0.0%	0.5%

Columbia Gas of Pennsylvania
REVENUE SUMMARY
R-2021-3024296
$87.9 Million Scale Back

LINE NO.	Tariff Revenue (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	Sales Customers		$576,669,411	$455,042,529	$48,942,578	$38,792,041	$8,494,617	$25,397,646		
2	Choice Customers		$127,445,589	$69,719,497	$15,663,091	$12,909,148	$29,153,853			
3	Cap Customers		$25,445,115	$25,445,115						
4	Choice Customers		$23,726,715		$2,148,327	$21,578,388	-$355,590	$355,590	-	
5	MDLS-1		$53,292						$53,292	
6	MDLS-2		$1,035,292						$1,035,292	
7	Negotiated		$3,647,747						$240,703	$3,407,044
8	TOTAL Tariff REVENUE		$758,023,161	$550,207,141	$66,753,996	$73,279,577	$37,292,880	$25,753,236	$1,329,287	$3,407,044
	Other Revenue		**TOTAL**	**RSS/RDS**	**SGS/DS-1**	**SGS/DS-2**	**SDS/LGSS**	**LDS/LGSS**	**MLDS**	**FLEX**
9	Forfeited Discounts		$1,450,097	$1,058,397	$128,783	$141,718	$57,380	$53,393	$2,929	$7,497
10	Miscellaneous Revenue		-$4,773	-$4,371	-$335	-$61	-$5	-$1	$0	$0
11	Other		$16,357	$14,997	$1,147	$209	$3	$0	$1	$0
12	Total Other		$1,461,681	$1,069,023	$129,595	$141,866	$57,378	$53,392	$2,930	$7,497
13	First Step Scale Back		-$36,000,000	-$36,000,000	$0	$0	$0	$0	$0	$0
14	Second Step Scale Back		-$26,700,000	-$21,000,000	-$3,000,000	-$2,700,000	$0	$0	$0	$0
15	Third Step Scale Back		-$25,200,000	-$18,000,000	-$2,500,000	-$2,800,000	-$1,900,000	$0	$0	$0
16	Percent of Third Step		100%	71%	10%	11%	8%			
17	TOTAL REVENUE		$671,584,842	$476,276,164	$61,383,591	$67,921,443	$35,450,258	$25,806,628	$1,332,217	$3,414,541
18	INCREASE		$10,378,114	-$7,236,376	$2,964,410	$3,631,299	$5,107,364	$5,895,248	$379	$15,790

Columbia Gas of Pennsylvania
Rate of Return under $87.9 Million Scale Back
R-2021-3024296

Allocated Cost of Service Study | **111, Schedule 2**
Peak and Average | **Page 1 of 13**
Winess C.E. Notestone

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
1	TOTAL REVENUE [PAGE 6]		$671,584,842	$476,276,164	$61,383,591	$67,921,443	$35,450,258	$25,806,628	$1,332,217	$3,414,541
2	PRODUCTS PURCHASED [PAGE 7]		$161,368,307	$119,615,901	$17,998,184	$19,709,532	$3,655,831	$168,466	$220,393	$0
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		$225,828,345	$162,866,636	$16,162,049	$15,609,339	$10,097,084	$11,653,755	$26,299	$9,413,183
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5	TAXES OTHER THAN INCOME [PAGE 9]		$3,715,938	$2,483,420	$310,109	$304,027	$197,500	$230,573	$249	$190,060
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		$500,882,918	$354,605,054	$43,695,761	$45,680,853	$20,573,521	$19,883,014	$276,360	$16,168,355
7	OPERATING INCOME BEFORE TAXES		$170,701,924	$121,671,110	$17,687,830	$22,240,590	$14,876,737	$5,923,614	$1,055,857	-$12,753,814
8	INCOME TAXES		$22,815,518	$14,370,570	$2,920,992	$4,862,725	$3,470,699	$1,045,230	$300,445	($4,155,142)
9	INVESTMENT TAX CREDIT	12	($243,013)	($149,834)	-$20,520	-$23,392	-$15,439	-$18,348	-$49	-$15,431
10	NET INCOME TAXES		$22,572,505	$14,220,736	$2,900,472	$4,839,333	$3,455,260	$1,026,882	$300,396	-$4,170,573
11	OPERATING INCOME		$148,129,419	$107,450,374	$14,787,358	$17,401,257	$11,421,477	$4,896,732	$755,461	-$8,583,241
12	RATE BASE [PAGE 10]		$2,673,012,065	$1,632,611,139	$224,690,377	$263,041,870	$173,378,146	$205,632,659	$479,273	$173,178,601
13	RATE OF RETURN EARNED ON RATE BASE		5.542%	6.582%	6.581%	6.615%	6.588%	2.381%	157.627%	-4.956%
14	UNITIZED RETURN		1.00	1.19	1.19	1.19	1.19	0.43	28.44	(0.89)
15	Percent Increase		1.57%	-1.5%	5.1%	5.6%	16.8%	29.6%	0.0%	0.5%

I&E Statement No. 3-R
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Rebuttal Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Cost of Service

TABLE OF CONTENTS

<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline. My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME ETHAN H. CLINE WHO SUBMITTED I&E STATEMENT NO. 3 AND I&E EXHIBIT NO. 3 ON JUNE 16, 2021?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to present a response to the direct testimony of Pennsylvania State University's ("PSU") witness James L. Crist, P.E. regarding the topic of cost of service.

<u>COST OF SERVICE</u>

Q. HOW DID THE COMPANY ALLOCATE THE PROPOSED REVENUE INCREASE?

A. As stated in my direct testimony, the Company used the results of the Peak & Average methodology when designing the proposed revenue requirement and rates (I&E St. No. 3, p. 37).

Q. DID YOU RECOMMEND UTILIZING THE PEAK AND AVERAGE COST OF SERVICE STUDY AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. Yes. I agreed with the Company's use of the Peak and Average methodology to allocate the cost of distribution plant and related expenses (I&E St. No. 3, p. 13).

Q. WHY IS THE PEAK AND AVERAGE METHODOLOGY THE MOST REASONABLE WAY TO ALLOCATE THE COST OF MAINS?

A. The peak and average methodology utilizes two factors to allocate the cost of mains, the peak flow and the average flow. This methodology recognizes that mains are used to deliver gas to customers and therefore mains investments are based on the load rather than number of customers.

Q. DID ANOTHER PARTY SUBMIT DIRECT TESTIMONY CONCERNING COST ALLOCATION STUDIES?

A. Yes. PSU Witness Crist provided direct testimony recommending that the Commission reject the use of the Peak and Average methodology and instead use the Customer-Demand methodology, which utilizes a combination of peak day demands and customer counts to assign mains cost responsibility (PSU St. No. 1, p 17).

Q. WHAT WAS THE BASIS FOR MR. CRIST'S RECOMMENDATION THAT THE COMMISSION RELY ON A COMBINATION OF THE COMPANY'S TWO COST OF SERVICE STUDIES?

A. Mr. Crist's position is that the reason the Company chose the Peak and Average methodology to allocate costs and revenues in this base rate case was "not because the use of the peak and average study was a more accurate reflection of cost causation, but only because the Commission, in one recent case, expressed a preference for the peak and average study due to 'errors' in the customer-demand study." (PSU St. No. 1, pp. 11-12).

Q. WHAT STATEMENT IN THE RECENT 2020 COLUMBIA ORDER AT DOCKET NO. R-2020-3018835 DID MR. CRIST REFERENCE?

A. Mr. Crist referenced a statement from the Administrative Law Judge's ("ALJ") Recommended Decision ("RD") that the customer-demand would be the preferred method were it not for errors and the Commission's statement that it was not persuaded to reverse the ALJ's RD and concluded that the Commission must, therefore, also support the customer-demand methodology apart from certain errors that were not included in the current proceeding (PSU St. No. 1, pp. 12-14).

Q. DO YOU AGREE WITH MR. CRIST'S ANALYSIS OF THE COMMISSION'S ORDER RESOLVING COLUMBIA'S LAST BASE RATE CASE AT DOCKET NO. R-2020-3018835?

A. No. Mr. Crist's analysis of the Commission's Order resolving Columbia's last base rate case at Docket No. R-2020-3018835, Order entered February 19, 2021 ("2020 Columbia Order") is inaccurate and misleading.

Q. WHY IS MR. CRIST'S ANALYSIS OF THE 2020 COLUMBIA ORDER INACCURATE AND MISLEADING?

A. Mr. Crist's analysis of the 2020 Columbia Order conveniently omits the rest of the Commission's discussion of the peak and average methodology. Specifically, Mr. Crit fails to recognize page 215 of the 2020 Columbia Order in which the Commission stated the following:

> Based on our review of the record, and as noted by the ALJ, we have consistently used the Peak & Average methodology for the allocation costs for NGDCs. In this regard, we find that the Customer-Demand method and the Average ACCOSSS, which depends on the Customer-Demand methodology, would be inconsistent with Commission precedent and generally accepted principles for NGDCs because they both contain customer cost components.

The Commission also concluded on page 218 of the 2020 Columbia Order saying, "we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment." These statements from the 2020 Columbia Order completely refute what Mr. Crist claimed was the Commission's ruling.

Q. DID MR. CRIST PROVIDE ANY OTHER RATIONALE FOR SUPPORTING THE CUSTOMER-DEMAND METHODOLOGY?

A. Mr. Crist's rationale for supporting the customer-demand methodology is his claim that the Company uses delivery pressure and length of pipe necessary to attach to the customer are the only data used in gas main design and sizing (PSU St. No. 1, p. 15).

Q. DO YOU AGREE WITH MR. CRIST'S POSITION THAT THE CUSTOMER-DEMAND METHODOLOGY SHOULD BE THE PREFERRED METHOD FOR COST ALLOCATION?

A. Not at all. Mr. Crist's insistence that costs should be allocated based on the customer-demand methodology because of how the Company stated the system is designed is not consistent with the Commission's historic determination of cost causality.

Q. IS MR. CRIST'S BELIEF SUPPORTED BY THE COMMISSION?

A. No. The Commission stated on page 217 of the 2020 Columbia Order that "we remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment, not the number of customers served."

Q. IF MR. CRIST'S POSITION IS ACCEPTED, WILL THE CONCEPT OF COST CAUSATION BE VIOLATED AND WHO WILL ULTIMATLEY BEAR THE COSTS THAT HIS CLIENT IS TRYING TO AVOID PAYING?

A. I agree with Mr. Crist's statement on page 8 of PSU Statement No. 1 that the principle of cost causation "may not be violated just because some customers do not like bearing the costs or want to lessen the impact of the cost of the benefits they receive at the expense of others, nor may it be violated because a utility wishes to benefit one customer class at the expense of another." However, as described above, Mr. Crist's position that does, in fact, violate the principle of cost causation for the reasons stated by the Commission. Mr. Crist's recommendation would shift costs away from his client in order to lessen the impact of the cost of the benefits they receive at the expense of the other customers on the system, which is unfair to those customers that will bear the cost.

Q. SHOULD THE RECOMMENDATION OF MR. CRIST BE ACCEPTED BY THE COMMISSION?

A. No. The Commission should not reverse itself and has previously reflected the proper recognition that distribution mains are built on the basis of year-round demands as well as peak demands. Mr. Crist did not provide any reasonable rationale to accept a methodology that the Commission rejected less than six months ago.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 3-SR
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2021-3024296

Surrebuttal Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Revenue Normalization Adjustment
Present Rate Revenue
Cost of Service Study
Scale Back of Rates

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline. My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME ETHAN H. CLINE WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 3, THE SCHEDULES IN I&E EXHIBIT NO. 3, SUBMITTED ON JUNE 16, 2021, AND THE REBUTTAL TESTIMONY CONTAINED IN I&E STATEMENT NO. 3-R, SUBMITTED ON JULY 14, 2021?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony submitted by witnesses on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company"): Melissa J. Bell (Columbia Statement No. 3-R) and Nicole Shultz (Columbia Statement No. 6-R). I will also address the rebuttal testimony submitted on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") by witness Jerome D. Mierzwa (OCA Statement No. 3-R), the rebuttal testimony submitted on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA") by witness Robert D. Knecht (OSBA Statement No. 1-R), the rebuttal testimony submitted on behalf of Columbia Industrial Intervenors ("CII") by witness Frank Plank (CII Statement No. 1), and the rebuttal testimony submitted on behalf of the Pennsylvania State University ("PSU") by James L. Crist, P. E. (PSU Statement No. 1-R). My surrebuttal testimony specifically addresses the following issues:

- Fully Projected Future Test Year Reporting Requirements;
- Revenue Normalization Adjustment;
- Present Rate Revenue;
- Cost of Service allocation;
- Customer Charges; and
- Scale back of rates.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. However, I will refer to my direct and rebuttal testimonies and exhibits in this surrebuttal testimony.

Q. DID THE COMPANY AGREE WITH ANY OF YOUR RECOMMENDATIONS?

A. Yes. The Company agreed with my recommendation regarding Fully Projected Future Test Year ("FPFTY") Reporting Requirements as presented on page 3 of I&E Statement No. 3 (Columbia Gas Statement No. 6-R, pp. 3-4). The Company also agreed with my recommendation that the Company's present rate revenue claim for miscellaneous service revenue be increased by $59,635 from negative $4,774 to $54,861 as presented on page 9 of I&E Statement No. 3 (Columbia Gas St. No. 3-R, p. 39).

REVENUE NORMALIZATION ADJUSTMENT

Q. DID YOU AGREE WITH THE COMPANY'S PROPOSED RNA?

A. No. On page 6 of I&E Statement No. 3, I recommended that the proposed RNA not be approved for three reasons. First, the Commission recently issued its Order in the 2020 Columbia Gas base rate case where it determined that RNA was unnecessary. Second, the policy statement cited by the Company as support for its position does not allow Columbia to abandon the necessity to charge just and reasonable rates. Lastly, the use of the FPFTY already provides projected lower usage levels and the Company has not demonstrated a need for such revenue stabilization in the instant proceeding.

Q. DID THE COMPANY RESPOND TO YOUR POSITION?

A. Yes. The Company did not agree with my recommendation regarding the RNA.

Q. WHY DID THE COMPANY NOT AGREE WITH YOUR RECOMMENDATION REGARDING THE RNA?

A. The Company did not agree with my recommendation regarding the RNA for all three reasons. First, the Company claimed that the Commission did not determine that the RNA was not necessary. Second, Columbia claimed that the introduction of the RNA does not abandon the Company's necessity to charge just and reasonable rates. Third, the Company claimed that the FPFTY mitigates, but does not eliminate, the need for the RNA (Columbia St. No. 3-R, pp. 25-26).

Q. WHY DID THE COMPANY CLAIM THAT THE COMMISSION DID NOT DETERMINE THAT THE RNA WAS NOT NECESSARY?

A. On page 24 of Columbia Statement No. 3-R, the Company cited to pp. 264-265 of the Commission's Order at Docket No. 2020-3018835, Order entered, February 19, 2021, which stated that the ALJ recommended that the Commission deny the RNA proposal because "Columbia failed to prove the RNA Rider is ***needed*** and reasonable, or that the RNA Rider will result in rates that are just, reasonable and in the public interest. Further, the Company did not show its current rates and systems of revenue streams will fail to provide revenue stability." (emphasis added). Witness Bell then attempted to claim that this Order applied only to the RNA in that specific case and also noted that "Columbia did not file any Exceptions to this issue in the 2020 case, and thus did not present full argument to the Commission on this issue." (Columbia St. No. 3-R, pp. 24-25)

Q. DID THE COMMISSION, IN ITS ORDER RESOLVING THE 2020 CASE, GIVE ANY INDICATION THAT ITS DECISION APPLIED TO THE RNA ONLY IN THAT CASE?

A. No. The disposition of this issue, on page 264 of Docket No. 2020-3018835, Order entered February 19, 2021, simply stated that "[w]e find that the ALJ's recommendation is supported by ample record evidence and is just and reasonable. Accordingly, we shall adopt it without further comment."

Q. DID COLUMBIA GAS PROVIDE ANY SUPPORT IN THE PRESENT PROCEEDING TO COUNTER THE COMMISSION'S RULING THAT THE RNA IS NOT NEEDED, NOT JUST AND REASONABLE, AND NOT IN THE PUBLIC INTEREST?

A. No. As I stated on page 6 of I&E Statement No. 3, the Company did not make any substantial changes to the RNA proposal that was denied in Columbia's 2020 base rate case, other than adding a reference to the alternative ratemaking Statements of Policy at Docket No. M-2015-2518883. Therefore, because the Company's current proposal is unchanged from the Company's proposal in the 2020 base rate case that was rejected by the Commission as not needed, not just and reasonable, and not in the public interest, there is no reason for the Commission to change its decision to deny the RNA in this case.

Q. WHY DID COLUMBIA CLAIM THAT THE INTRODUCTION OF THE RNA DOES NOT ABANDON THE COMPANY'S NECESSITY TO CHARGE JUST AND REASONABLE RATES?

A. On page 26 of Columbia Statement No. 3, witness Bell stated that the Company did not abandon its necessity to charge just and reasonable rates because the base rates established by the Commission in this case will be just and reasonable. Witness Bell then claimed that the RNA would complement the residential rate design to better ensure the revenue requirement assigned to the residential class is not over or under recovered due strictly to rate design.

Q. DO YOU AGREE THAT THE INTRODUCTION OF THE RNA WOULD LEAD TO RATES THAT ARE JUST AND REASONABLE?

A. No. As I stated on page 7 of I&E Statement No. 3, and above, the Commission ruled in the 2020 Columbia Gas base rate case that the RNA would not result in rates that are just, reasonable, and in the public interest. As the Company has proposed essentially the same RNA proposal in this case with no adjustments introduced to counter the Commission's ruling, then that ruling clearly states that the proposal would necessarily lead to rates that are not just, reasonable, or in the public interest.

Q. WHY DOES COLUMBIA CLAIM THAT THE NEED FOR THE RNA IS MITIGATED, BUT NOT ELIMINATED, BY THE USE OF THE FPFTY?

A. On page 25 of Columbia Statement No. 3-R, witness Bell states that the RNA is needed because "Columbia's financial health directly relies upon its ability to recover the cost of service approved by the Commission through the base non-gas revenues upon which its base rates were previously established."

Q. IS THE PROBLEM OF REVENUE STABILITY AN ISSUE THAT REQUIRES ELIMINATION, RATHER THAN MITIGATION, AS THE COMPANY SUGGESTS?

A. No. Every utility in the Commission's jurisdiction must deal with the issue of balancing revenue stability with rate affordability and conservation efforts. Even though Columbia has proposed the RNA and not been granted the RNA in several rate cases, the Company has continued to provide its customers with safe and reliable service while maintaining an aggressive main replacement program. The Company has not provided any evidence to support its claimed need for additional rate stability beyond what is provided through the FPFTY.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION?

A. No. I continue to recommend that the RNA be denied.

COST OF SERVICE

Q. DID THE COMPANY PROVIDE AN ALLOCATED COST OF SERVICE STUDY IN THIS PROCEEDING?

A. Yes. The Company performed and provided three allocated cost of service ("ACOS") studies in its filing sponsored by Columbia witness Bell as described on pages 2-3 of Columbia Statement No. 3-R. The first is a customer-demand ACOS study (Columbia Exhibit No. 111, Schedule 1), the second is a peak and average ACOS study (Columbia Exhibit No. 111, Schedule 2), and the third ACOS study is an average of the customer-demand studies and the peak and average studies (Columbia Exhibit No. 111, Schedule 3).

Q. WHICH OF THE THREE ACOS STUDIES DID THE COMPANY UTILIZE TO ALLOCATE THE PROPOSED REVENUE INCREASES?

A. The Company utilized the second ACOS study, which is the peak and average study, presented on Columbia Exhibit No. 111, Schedule No. 2 to allocate the proposed revenue increases (Columbia St. No. 3-R, p. 3).

Q. WHICH ACOS STUDY DID YOU RECOMMEND THE COMMISSION USE?

A. I agreed with the Company's use of the peak and average ACOS study provided by the Company on Columbia Exhibit No. 111, Schedule 2 to allocate the final revenue increases among the different customer classes (I&E St. No. 3, p. 13).

Q. DID OTHER PARTIES DISAGREE WITH YOUR RECOMMENDATION THAT ONLY THE PEAK AND AVERAGE ACOS SHOULD BE USED IN THIS PROCEEDING?

A. Yes. PSU Witness Crist opposed my use of only the peak and average ACOS in allocating costs in this proceeding stating that I did not address that the ALJ in the last case preferred the customer-demand ACOS but did not use it due to errors (PSU St. No. 1-R, p. 6).

Q. PLEASE RESPOND TO THE PSU OPPOSITION TO THE USE OF THE PEAK AND AVERAGE ACOS IN COST ALLOCATION.

A. As I stated in I&E Statement No. 3-R, the purpose of which was to rebut PSU witness Crist's position regarding the ACOS, Mr. Crist's analysis of the Commission's Order resolving Columbia's last base rate case at Docket No. R-2020-3018835, Order entered February 19, 2021, is inaccurate and misleading (I&E St. No. 3-R, p. 5). Therefore, I continue to recommend that the Peak and Average methodology be used to allocate costs in this proceeding.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION REGARDING THE COMPANY'S ACOS?

A. No. I continue to recommend that the Commission use the peak and average ACOS study provided by the Company on Columbia Exhibit No. 111, Schedule 2 to allocate the final revenue increases among the different customer classes.

CUSTOMER COST ANALYSIS

Q. WHAT DID YOU RECOMMEND REGARDING THE COMPANY'S CUSTOMER COST ANALYSES?

A. I recommended the Company's customer cost analysis that includes the cost of mains should not be considered (I&E St. No. 3, pp. 16-17).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. Ms. Bell stated on page 17 of Columbia Statement No. 3-R that "[a] customer charge should include at a minimum the incremental cost the utility incurs in connecting a customer to the distribution system." She also stated that the customer cost analysis shows a minimum floor in which fixed costs should be recovered.

Q. DO YOU AGREE WITH THE WITNESS BELL'S STATEMENTS REGARDING THE CUSTOMER COST ANALYSIS?

A. No. First, the Commission has previously determined the costs that should be allowed in a customer cost analysis. The cost of mains is not included in those costs. In fact, on page 218 of Docket No. 2020-3018835, Order entered February 19, 2021, the Commission used Columbia's acknowledgement of the Commission's preference that no portion of fixed costs or depreciation expense associated with mains should be allocated to the customer cost function as further support for its conclusion that the allocation of mains should not be based on the number of customers. Therefore, witness Bell's statement regarding the customer cost analysis including the incremental cost to serve does not comport with Commission precedent.

Second, the Company's position that the customer cost analysis provides a minimum floor for which fixed costs should be recovered is entirely incorrect. Specifically delineating costs that are approved by the Commission to be recovered through the customer cost and then setting rates that recover more than those costs, as the Company suggests, makes no sense. The customer cost analysis, in my experience, has always been set as the maximum limit of the customer charge.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION?

A. No. For the reasons described above, I continue to recommend the Company's customer cost analysis that includes the cost of mains should not be considered.

<u>CUSTOMER CHARGES</u>

Q. WHAT DID YOU RECOMMEND REGARDING THE COMPANY'S PROPOSED CUSTOMER CHARGE?

A. On pages 18-19 of I&E Statement No. 3, I indicated that based on the customer cost analysis, not including the cost of mains, the customer charges for the SGS1, SGS2, and SDS/LGSS classes are too high. I recommended those customer charges be adjusted to be consistent with the customer cost analysis as follows:

Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Present Rate	Company Proposed Rate	Change	I&E Proposed Rate
	RS, RDS, RCC				
All Usage	$24.23	$16.75	$19.33	$0.00	$19.33
	SGSS1, SCD1, SGDS1				
≤6,440	$27.03	$26.00	$31.50	($5.50)	$26.00
	SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$46.27	$55.00	$66.00	($11.00)	$55.00
	SDS/LGSS				
>64,400 to ≤110,000	$212.97	$265.00	$335.00	($70.00)	$265.00
>110,000 to ≤540,000	$1,055.67	$874.00	$1,104.00	($49.00)	$1,055.00

Q. DID ANY PARTIES RESPOND TO YOUR CUSTOMER CHARGE RECOMMENDATION?

A. Yes. First, Columbia witness Bell, on page 17 of Columbia Statement No. 3-R, disagreed with my recommendation based on her assumptions regarding the customer cost analysis as discussed above. Second, OCA witness Mierzwa opposed with my customer charge recommendations because he claimed the Company's customer charge is already the highest in the Commonwealth, Columbia's proposed residential customer charge will have a disproportionate effect on low-income customers, and a high fixed customer charge is inconsistent with the Commission's general goal of fostering energy conservation (OCA St. No. 3R, p. 5).

Q. DO YOU BELIEVE THE COMPARISON OF CUSTOMER CHARGES OF THE OTHER PENNSYLVANIA NATURAL GAS DISTRIBUTION COMPANIES SHOULD BE A DETERMINING FACTOR IN COLUMBIA'S CUSTOMER CHARGES?

A. No. Each Pennsylvania NGDC has their own specific costs and allocation of these costs which in turn produces different results. Therefore, the rates of each company should be determined based on the facts and data specific to that company. The customer charges I recommend are based on the customer cost analysis using the data specific to this case.

Q. DO YOU AGREE WITH OCA WITNESS MIERZWA THAT A HIGH FIXED MONTHLY CUSTOMER CHARGE COULD HAVE DISPROPORTIONATE IMPACT ON LOW-INCOME CUSTOMERS AND BE INCONSISTENT WITH THE COMMISSION'S GENERAL GOAL OF FOSTERING ENERGY CONSERVATION?

A. Yes. However, I believe that my recommendation to include the customer charge in the scale back of rates would serve to mitigate the impacts to low-income customer and be consistent with the Commission's general goal of fostering energy conservation while recognizing that the Company's allowed fixed costs are increasing as shown in the customer cost analysis.

Q. DO YOU WISH TO CHANGE YOUR CUSTOMER CHARGE RECOMMENDATION?

A. No. For the reasons discussed above, I continue to recommend the customer charges shown in the table above.

<u>SCALE BACK OF RATES</u>

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommended that the first $36,000,000 reduction be applied to the RSS/RSD class (I&E Ex, No. 3, Sch. 4, p. 1, line 13). The next $26,700,000 reduction should be applied to the various classes as shown on I&E Exhibit No. 3, Sch. 5, p. 1, line 14). Any scale back between $36,000,000 and $62,700,000 ($36,000,000 + $26,700,000) should be interpolated between the revenue levels shown on I&E Exhibit No. 3. Sch. 5, p. 1, lines 13 and 14. On page 22 of I&E Statement No. 3, I recommend that if the Commission grants a decrease greater than $62.7 million, I recommended the 71% of the reduction be applied to the RSS/RSD class, that 10% be applied to the SGS/GS-1 class, that 11% be applied to the SGS/GS-2 class and that 8% be applied to the SDS/LGSS class (I&E Exhibit No. 3, Sch. 6, p. 1, lines 15-16). This recommendation excludes the LDS/LGSS, MLDS and Flex rate classes. (I&E St. No. 3, pp, 20-22)

Q. PLEASE SUMMARIZE THE RATIONALE OF YOUR SCALEBACK RECOMMENDATION.

A. As I stated on page 22 of I&E Statement No. 3, "The LDS/LGSS class rates should not be scaled back because the relative rate of return under proposed rates is so low. The MLDS class should not be scaled back because the Company did not propose any increase for this class. The Flex class should not be scaled back because these customers pay negotiated rates." While my recommendation does represent a large increase for the LDS/LGSS rate class, the low relative rate of return of this class shows that the other rate classes have been subsidizing the LDS/LGSS rate class. I believe that this subsidization should be removed as quickly as possible.

Q. DID THE COMPANY OPPOSE YOUR PROPOSED SCALE BACK METHODOLOGY?

A. Yes. Ms. Bell, on page 16 of Columbia Statement No. 3-R, stated that my recommendation is trying to get to parity in one rate case but by doing so I am exceeding any reasonable definition of gradualism.

Q. DOES YOUR PROPOSAL RESULT IN UNREASONABLE RATES?

A. No. Since I'm starting with the rates proposed by the Company. It makes no sense for the Company to now claim that those exact rates will somehow become unreasonable if the Commission grants less than the full increase. The higher percentage increase for the LDS/LGS class is necessary to move the relative rate of return of this class towards one under proposed rates. If these rates were reasonable to begin with, they will be reasonable after the final order.

Q. DID ANY OTHER PARTIES OPPOSE YOUR PROPOSED SCALE BACK METHODOLOGY?

A. Yes. OSBA witness Knecht opposed my recommendation and concluded that my scale back proposal would fail to move rates for small business customers more into line with allocated cost, be inconsistent with normal rate gradualism constraints in Pennsylvania, and assign inequitable rate increases to Medium and Large General Service rate classes. CII witness Frank Plank opposed my recommendation because the LDS rate class would receive little to no scale back under my recommendation (CII St. No. 1-R, pp. 7-8).

Q. DO YOU AGREE WITH MR. KNECHT.

A. No. My recommendation is reasonable because under proposed rates, the relative rate of return for the SGS/DS-1 class is approximately **1.2**, the same relative rate of return as the RSS/RDS class (I&E Ex. No. 3, Sch, 4, p. 2, Sch. 5, p. 2).

Q. WHY ARE MR. KNECHT'S RESULTS DIFFERENT?

A. Mr. Knecht adjusted the revenue shortfall associated with flex rate customers using his own methodology (OSBA St. No. 1, p. 16). Since my proposed scale back is based upon the Company's allocation methodology, rather than OSBA's, the resulting rates of return in my recommendation are different than those of Mr. Knecht.

Q. DO YOU AGREE WITH MR. PLANK?

A. No. Similar to the Company, Mr. Plank believes the increase to the LDS/LGS class should be limited and included in the scale back of rates. While I understand that the final percentage increase for the customer in this class will be greater than the system average increase, the very low present relative rate of return justifies excluding the LDS/LGS class from any scale back if the Commission grants less than the full increase (I&E Ex. No. 3, Sch, 4, p. 2, Sch. 5, p. 2).

Q. DO YOU WISH TO CHANGE YOUR SCALE BACK RECOMMENDATION?

A. No

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

OCA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC	:	
UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
COLUMBIA GAS OF	:	
PENNSYLVANIA, INC.	:	

DIRECT TESTIMONY OF

DAVID J. EFFRON

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

JUNE 16, 2021

DOCKET NO. R-2021-3024296
COLUMBIA GAS OF PENNSYLVANIA
DIRECT TESTIMONY OF DAVID J. EFFRON
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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant, and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses, I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over two hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North

Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. What is the purpose of your testimony?

A. I have calculated the measures of value (or rate base) and pro forma operating income under present rates of Columbia Gas of Pennsylvania, Inc. ("Columbia," or "the Company") in this rate case, based on the adjustments to the Company's position that I am presenting in this testimony. I have also incorporated the overall rate of return recommended by Mr. O'Donnell into my calculation of the present revenue deficiency of the Company. The calculation of the Company's revenue deficiency in this testimony is based on issues that I have identified. At the time of the preparation of this testimony, the Company had not responded to all of the OCA's data requests. I reserve the right to modify or amend my testimony based on responses to those outstanding data requests.

III. REVENUE REQUIREMENT ISSUES

A. SUMMARY

Q. What revenue deficiency or excess have you calculated based on the Company's fully projected future test year ("FPFTY") as filed?

A. Based on the FPFTY consisting of the 12 months ending December 31, 2022, I have calculated jurisdictional rate base (measures of value) of $2,596,006,000 and pro forma jurisdictional operating income under present rates of $161,664,000. Based on the overall rate of return of 6.48% recommended by Mr. O'Donnell, the Company presently has an operating income deficiency of $6,537,000. This translates into a revenue deficiency of $8,903,000 under present rates. This is $89,375,000 less than the revenue deficiency of $98,278,000 presented by the Company in its filing. My calculation of the Company's revenue deficiency is summarized on my Schedule A. I have also prepared Table I and Table II, which summarize the effect of my adjustments in the format used by the Commission.

B. MEASURES OF VALUE

1. PLANT IN SERVICE

Q. Have you analyzed the Company's forecast of plant in service included in the FPFTY rate base?

A. Yes. The forecasted additions to plant in service by month from December 2020 through December 2022 are shown on Company Exhibit 108, Schedule 1. The budgeted capital expenditures by activity are shown in the response to OCA Data Request II-1. Company Witness Brumley also addresses the Company's capital spending programs for the years 2020 – 2022 in his direct testimony. The Company is projecting net plant additions (gross plant additions less retirements) of $335,340,000 in 2021 and $324,536,000 in 2022.

Q. How does this compare to net plant additions in recent years?

A. The forecasted plant additions for both 2021 and 2022 are significantly higher than the net plant additions in recent years. In 2018, the net plant additions were approximately $210 million, in 2019 the net plant additions were approximately $294 million, and in 2020 the net plant additions were approximately $278 million.

Q. What accounts for the increased level of plant additions being forecasted for 2021 and 2022?

A. As can be seen in the table on Company Statement No. 7, Page 4, the increase from 2020 to 2021 is related mainly to "Betterment," which includes mains and services improvements and major projects. The increase in 2022 relates mainly to plant additions related to age and condition.

Q. Should the Company's forecast of additions to plant in service in 2021 and 2022 be modified?

A. Yes. As noted above, the forecasted plant additions for both 2021 and 2022 are well in excess of the actual plant additions in recent years. Further, referring to Exhibit 108, Schedule 1, it can be seen that the magnitude of the forecasted net additions to plant in service in the last quarter of both 2021 and 2022 are well in excess of the net additions in the earlier months of the year. In both of those years, the forecasted net additions in the last quarter account for almost one-half of the forecasted net additions for the whole year. Obviously, we will not know if those forecasts for the final quarters are accurate before the close of the record in this case.

Q. Did the Company explain why the rate of additions in the last quarter is so much greater than the rate of additions in the earlier months?

A. With regard to the forecasted additions in the last months of the FPFTY, the Company stated that "Plan [sic] additions for the year follow those seen in historical actuals, adjusted for major projects, etc. that may impact the historical average. Most work is performed during the summer/fall months, making it complete and placed into service in Q4" (Response to OCA Data Request I-002).

Q. Does the pattern of net plant additions in the historic test year ("HTY") in the present case support the Company's forecasted pattern of net plant additions in the future test year ("FTY") and FPFTY?

A. No. The net additions in the last quarter of 2020 were approximately $81 million. This accounted for about 29% of the net plant additions for the whole year. So while the rate of net additions for the last quarter of 2020 was slightly greater than rate of net additions for 2020 as a whole, the differential is nowhere near as far out of proportion as what the Company is reflecting in the FTY and FPFTY, the explanation in the response to OCA Data Request I-002 notwithstanding.

Q. What do you recommend?

A. In 2019, the net additions to plant in service were $294,610,000. In 2020, the net additions to plant in service were $277,795,000. The average of the net plant additions for those two years is $286,203,000. Given the relatively stable level of plant additions over this two-year period, I believe that it reasonable to use this two-year average as an estimate of net plant additions for the FTY and FPFTY.

The two-year average is $49,138,000 less than the net plant additions forecasted by the Company for the FTY and $38,334,000 less than the net plant additions forecasted by the Company for the FPFTY. Therefore, I recommend that the plant in service included by the Company in the 2022 FPFTY rate base be reduced by $87,471,000.

Consistent with this adjustment to plant, I am also proposing to reduce the related test year balances of depreciation reserve and accumulated deferred income taxes. The resulting net reduction to the test year rate base is $82,165,000 (my Schedule B-1). The reduction to plant in service also results in a reduction to test year depreciation expense of $2,187,000 (my Schedule C-2). I have also adjusted rate base to reflect a $1,095,000 correction to the balance of accumulated deferred income taxes referenced in the Company's response to OCA Data Request I-008 (my Schedule B).

Q. Does your proposed adjustment to the balance of plant in service in the FPFTY impose any risk of under-recovery on the Company?

A. No. Company Witness Kempic addresses the availability of the Distribution System Improvement Charge ("DSIC") in his Direct Testimony (Columbia Statement No. 1, page 6). Once the Company's investment in DSIC eligible plant exceeds the projected balances from the prior rate case, the Company will be able to restart its DSIC to recover the incremental investment that exceeds the projected test year balances. Thus, if the Company's forecast of FPFTY plant balances in the present case is reduced as I am proposing, then the DSIC would "kick in" when those reduced balances are exceeded. The Company would then be made whole through the operation of the DSIC.

If there is no adjustment to the Company's forecasts and the Company's actual additions in the FTY and FPFTY are short of its forecasts, the customers will be paying for the cost of plant that does not exist in FPFTY. On the other hand, if my adjustment is accepted and the Company's actual additions are in excess of my proposed plant additions, the Company will be able to recover any such excess through the DSIC. I believe that it is worth noting that in Columbia's last case, with regard to a similar proposal made by the OCA, the Commission found that "the OCA's proposal, that if the Company in fact spends more in investment than its average spending from actual 2018 through its projection in 2020, the DSIC is available to recover those additional expenses as necessary, is reasonable and protects customers from overpaying for plant not in service if the Company's significant increase in spending does not come to fruition."[1]

Accordingly, I believe that my proposed adjustment to the Company's projection of FPFTY plant is reasonable, and it poses no risk of under-recovery to the Company.

C. OPERATING INCOME

1. OPERATION AND MAINTENANCE EXPENSE

a. Labor Expense

Q. What labor expense does the Company include in pro forma FPFTY operation and maintenance expenses?

A. The Company includes salaries and wages of $39,678,000 in FPFTY test year expenses (Columbia Exhibit 104, Schedule 1). This represents an increase of

[1] Columbia Gas of Pennsylvania, Inc, R-2020-3018835, Opinion and Order, February 19, 2021, at 62

$3,294,000 from the actual salaries and wages expense of $36,384,000 incurred in the HTY. The adjustments to get from the HTY to the FPFTY include wage increases, the filling of budgeted vacancies, employee reductions related to the NiSource Next initiative ("NiNext," described in Columbia Statement No. 1, at Pages 11-12), reallocation between expense and capital, and what the Company labels as "Rate Making Adjustments" and "Other" (Standard Data Request Gas-RR-26).

Q. Are you proposing to adjust the Company's forecast of pro forma FPFTY labor expense?

A. Yes. I am proposing to adjust the number of employees included by the Company in the FPFTY labor expense. I am also proposing to eliminate the adjustments to labor expense designated as "Other" in Standard Data Request Gas-RR-26.

Q. Please summarize the net changes in the number employees being forecasted by the Company from the HTY to the FPFTY.

A. As of the end of the HTY, November 30, 2020, there were 767 employees (Standard Data Request Gas-RR-26). The Company is forecasting that the filling of vacancies existing at that time will result in an increase of 47 employees by the end of the FTY. This will be partially offset by a decrease of 16 employees due to the NiNext program. Thus, the Company is forecasting a net increase of 31 employees, from 767 to 798, from the end of the HTY to the end of the FTY. No further change is forecasted from the end of the FTY to the end of the FPFTY.

Q. Is the increase in the number employees taking place as forecasted by the Company in the FTY?

A. No. The Company provided the actual number of employees by month through April 2021 in the response to OCA VII-13. As of November 30, 2020 there were 767 employees. This number had decreased to 759 employees as of January 31, 2021, and then increased to 771 employees as of April 30, 2021. Thus, the number of employees as of April 30, 2021 was four more than the number of employees as of November 30, 2020. As such, this increase does not appear to be anything more than the normal "ebb and flow" in the number of employees that take place from time to time. For example, even with that slight increase in April 2021, the employee complement as of April 30 2021 was still lower than it was one year earlier.

While there was a small net increase in the number of employees since the end of the HTY, the increase is not of the magnitude forecasted by the Company. Therefore, the number of employees used in determining the pro forma FPFTY labor expense should be adjusted.

Q. How are you proposing to adjust the Company's forecast of the number of FPFTY employees?

A. As noted above, the number of employees as of April 30, 2021 was 771. While it is not clear that this represents a permanent increase in the number of employees since the end of the HTY, I do not believe that it is unreasonable to use this number as the normal level of employees for the purpose of determining the pro forma FPFTY labor expense.

Further, Columbia Statement No. 7 at 17 notes that "most recently, Columbia hired two new Public Affairs Specialists to work with its Manager of Municipal Affairs to work directly with municipalities to review proposed or passed local public policies that may impact Columbia's proposed work." Based on the Company's description, it appears that the activities of these two recently hired employees are akin to lobbying, which should not be recoverable in the cost of service. The number of employees as of April 30, 2021, exclusive of the two new Public Affairs Specialists is 769. This is 29 fewer than the 798 FPFTY employees projected by the Company. Therefore, I am proposing to reduce the Company's projected FPFTY employee complement by 29.

Q. What is the effect of your proposed reduction to the number of FPFTY employees?

A. On my Schedule C-1.1, I have calculated that reducing the FPFTY employee complement by 29 results in a decrease of $1,076,000 to labor costs included in pro forma FPFTY operation and maintenance expenses.

Q. Please describe your elimination of the adjustments to labor expense designated as "Other" on Standard Data Request Gas-RR-26.

A. OCA Data Request I-018, asked the Company to "explain what the 'Other' Adjustments in Columns (9) and (16) represent, and provide all documentation and workpapers supporting those adjustments." The response gave a general explanation of the "Other" adjustments, but did not provide any documentation or workpapers supporting those adjustments. As the “Other” adjustments lack any substantive support, I have eliminated them from pro forma FPFTY labor expense. Elimination of the “Other” adjustments reduces pro forma labor expense by $87,000 (my Schedule C-1.1).

Q. Please summarize your adjustments to pro forma FPFTY labor expense.

A. I have reduced pro forma FPFTY labor expense by $1,076,000 to eliminate the addition of 29 employees, and I have reduced pro forma FPFTY labor expense by $87,000 to eliminate the Company’s “Other’ adjustments, for a total reduction to labor expense of $1,163,000. In addition, I have also calculated a $306,000 decrease to FPFTY employee benefits expense (my Schedule C-1.1) related to the reduction of 27 employees.

b. Incentive Compensation

Q. Does the FPFTY include incentive compensation expense?

A. Yes. The FPFTY includes $2,445,000 of incentive compensation (SDR-GAS-RR-026) in operations and maintenance expense. This represents an increase of 56% over the $1,566,000 of normalized incentive compensation expense incurred in the HTY, (as corrected in the response to I&E Data Request RE-017). This increase takes place mainly in the FTY, where the forecasted incentive compensation expense increases from the normalized HTY level of $1,566,000 to $2,363,000. Based on the response to I&E Data Request RE-017, this incentive compensation represents payments to all classes of employees, not executive bonuses.

Q. Was the Company asked to explain how the FTY and FPFTY incentive compensation expense was determined?

A. Yes. I&E Data Request RE-017 asked the Company to "provide supporting workpapers and detailed calculations used to determine" the incentive compensation for the HTY, FTY, and FPFTY.

Q. Did the Company provide documentation that explained the increased incentive compensation from the HTY to the FTY and FPFTY?

A. No. With regard to the FTY, the Company stated that "This amount was budgeted based upon the salary and incentive potential percentage for each position. Each employee has annual eligible earnings that are defined as base wages plus, for nonexempt employees, overtime wages and shift premiums. The budget estimate is based upon the eligible earnings of each employee multiplied by their incentive value at 100% of target. Budgeting at target represents a normalized expected level of expense for the year" (Response to I&E Data Request RE-017). However, other than a table showing the breakout of incentive compensation between O&M and capital, there were no supporting workpapers, and there was no explanation of why the incentive compensation increased from a normalized level of $1,566,000 in the HTY to $2,363,000 in the FTY.

Q. Are you proposing to adjust the incentive compensation included in the total FPFTY labor expense?

A. Yes. Given the lack of documentation to support the increase in incentive compensation, I believe that it is more reasonable to assume that the ratio of incentive compensation to payroll expense in the FPFTY will be the same as the ratio of the normalized incentive compensation to payroll expense in the normalized HTY.

In the normalized HTY, the ratio of incentive compensation to payroll expense was approximately 4.12%. Applying this ratio to the FPFTY payroll expense of $39,678,000, the calculated incentive compensation is $1,635,000. This is $810,000 less than the $2,445,000 of incentive compensation included in the FPFTY by the Company. I have reflected this adjustment to FPFTY operation and maintenance expense on my Schedule C-1.

c. Stock Rewards

Q. Are stock rewards expenses included in FPFTY operation and maintenance expenses?

A. Yes. As described in the response to OCA Data Request I-25, Labor Expense includes $559,000 of stock rewards expense and the NCSC Shared Services Expense includes $2,217,000 of stock rewards expense.

Q. Is this expense appropriately includable in the Company's revenue requirement?

A. No. Stock rewards are a form of incentive compensation whose ultimate value is based solely on the attainment of financial goals by the parent company. Incentive compensation based solely on the attainment of financial goals, such as earnings, return on equity, or appreciation in the value of common stock of the utility's parent company should not be recoverable from ratepayers.

Q. Why is it inappropriate to include incentive compensation based on appreciation in the value of common stock of the parent company in the utility's revenue requirement?

A. Appreciation in the value of common stock is a shareholder-oriented goal, not a customer-oriented goal. For example, if all else is equal, higher rates will result in higher revenues, which in turn will result in higher earnings that increase the value of common stock. Thus, including such incentive compensation in the revenue requirement would, in effect, require customers to reward company management on a contingency basis for getting them to pay higher rates. If the incentive compensation program is successful in increasing earnings and common stock values, the shareholders should be happy to reward management accordingly and absorb the cost of the program. As shareholders are the beneficiaries of increases to common stock valuations, it should be those shareholders, not customers, who bear the cost of the stock rewards.

Q. What do you recommend?

A. I recommend that $2,776,000 of stock rewards expense ($559,000 Columbia expense plus $2,217,000 allocated from the parent company) be eliminated from pro forma test year operation and maintenance expense (my Schedule C-1).

d. Outside Services Expense

Q. What level of outside services expense does the Company include in FPFTY operation and maintenance?

A. The Company includes $28,437,000 of outside service expense in FPFTY operation and maintenance (Company Exhibit 104, Schedule 1, Page 2).

Q. How does this compare to the actual normalized outside services expense incurred in the HTY?

A. It is significantly higher. The actual normalized outside services expense in HTY was $18,737,000. The normalized outside services expense increases by $8,641,000 (nearly half) to $27,378,000 in the FTY and then by another $1,059,000 to $28,437,000 in the FPFTY. Outside services expense in the FPFTY is approximately 52% greater than the outside services expenses in the HTY.

Q. Did the Company provide any direct explanation or quantification of the factors causing the increase in outside services expense from the HTY to the FTY and the FPFTY in its Direct case?

A. As far as I can determine, it did not.

Q. Did the Company provide any further explanation of the increases in response to information requests?

A. Yes. In response to OCA Data Request I-036, the Company summarized “Budget Increases” from the HTY to the FTY totaling $8.6 million. There are nine separate activities ranging from $0.2 million to $1.7 million. There is no documentation supporting the amounts shown, no workpapers showing how the amounts were calculated, or any explanation of how the amounts were developed.

In the "OCA I-38" Tab included in the response to OCA Data Request I-037, the Company briefly described $1 million of the increase in outside services expenses from the FTY to the FPFTY as being the result of "increases in various field operational programs: Cross bores, Field Assembled Risers (Company and Customer owned), righ[t]s of way clearing, and GPS Legacy." Again, there is no support for the amount shown.

Q. Was the Company asked to provide any additional support for the expense increases from the HTY to the FTY as shown in the response to OCA Data Request I-036?

A. Yes. OCA Data Request VII-008 asked the Company to provide documentation and workpapers supporting each "Budget Increase over HTY" in the response to OCA Data Request I-036. The Company cross referenced its response to I&E-RE-070.

The response to I&E-RE-070 shows the actual spending on each of the activities in the response to OCA Data Request I-036 in the HTY, the budgeted spending on each of the activities for the FTY, the differences between them, and the actual spending on each of the activities in the FTY through April 2021. However, there is no further documentation or explanation of how the budgeted expenses for the FTY were developed.

Q. Are you proposing to modify the outside services expense included in the Company's FPFTY revenue requirement?

A. Yes. I do not believe that the Company has adequately supported its projected increases in outside services expense. Therefore, I am proposing to adjust the FPFTY outside services expense.

Company Exhibit No. 4, Schedule 1, Page 2 shows the actual outside services expense for the HTY and the two preceding years. Referring to this schedule, the actual outside services expense in the HTY was noticeably lower than the outside services for the two previous years. Based on Exhibit No. 4, Schedule 3, Page 2 and the responses to OCA Data Requests I-034 and VII-06, the decrease in the HTY appears to be due in part to reductions in reconnect services and line location expenses because of COVID-19 restrictions.

Taking the actual outside services expenses in the twelve month periods ended November 30, 2018 and 2019, and then using the Company's escalation factors to escalate the average of those expenses to the HTY to establish a normalized expense level for the HTY, the result is $23,469,000 (my Schedule C-1.2). Further escalating that amount to the FPFTY, the projected expense is $24,130,000. I recommend that the Company's forecasted FPFTY outside services expense be adjusted to reflect this amount.

Q. What is the effect of your proposed adjustment?

A. The effect is to reduce the Company's pro forma test year outside services expense by $4,307,000 (my Schedule C-1.3). I would note that even after this adjustment, the outside services expense that I am proposing to include in the Company's FPFTY revenue requirement is still $5.4 million (or approximately 29%) greater than the normalized outside services expense incurred in the HTY.

e. Rate Case Expense

Q. Has the Company included rate case expense in pro forma FPFTY operating expenses?

A. Yes. The Company includes $1,060,000 of rate case expense in pro forma test year operation and maintenance expenses. This consists of the estimated cost of the present rate case normalized over one year (Company Exhibit 4, Schedule 2, Page 27).

Q. Are you proposing to modify the pro forma rate case expense included in the Company's revenue requirement?

A. Yes. The Company's last four rate cases before the present case were filed in March 2015, March 2016, March 2018, and April 2020. Based on this experience, I believe that a normalization period of 1.5 years is more reasonable than the one-year normalization period used by the Company.[2]

Normalizing the estimated cost of the present case over 1.5 years, rather than one year, results in a reduction of $353,000 to the annual rate case expense included in the Company's revenue requirement (my Schedule C-1).

[2] The average time between the March 2015 case to the present case is calculated as ((1+2+25/12+11/12)/4) = 1.5

f. NCSC Expense

Q. Does the FPFTY revenue requirement include expenses allocated from NiSource Corporate Services Company ("NCSC")?

A. Yes. The FPFTY revenue requirement includes $76,860,000 of expenses allocated from NCSC.

Q. How does this compare to the actual NCSC expenses allocated to Columbia Gas of Pennsylvania in the HTY?

A. It is significantly higher. The actual NCSC expense allocated to the Company in HTY was $60,507,000. After elimination of non-recurring and non-recoverable expenses, the normalized NCSC expense in the HTY was $58,867,000. The normalized NCSC expense increases by $14,639,000 (over 25%) to $73,507,000 in the FTY and then by another $3,353,000 to $76,860,000 in the FPFTY.

Q. Did the Company provide any direct explanation or quantification of the factors causing the increase in the allocation of NCSC expenses from the HTY to the FTY in its Direct case?

A. As far as I can determine, it did not.

Q. Did the Company provide a breakdown of the NCSC increases in response to data requests?

A. In response to OCA Data Request I-037, the Company summarized the factors causing the increase from the HTY to the FTY. The increase was caused mainly by two factors: the divestiture by NiSource of Columbia Gas of Massachusetts ("CMA"), $11.4 million, and "Safety Plan," $5.1 million. The NCSC FTY expenses are also affected by the NiNext program savings and other factors.

Q. Why did the divestiture of CMA cause an increase in NCSC expenses allocated to the Columbia Gas of Pennsylvania?

A. As explained by the Company, as a result of the sale of CMA in 2020 "there was one less company in which to allocate NCSC costs." In other words there was one less affiliate over which to spread the fixed costs incurred by NCSC. The Company calculated that the share of NCSC costs allocated to Columbia Gas of Pennsylvania would increase from 13.94% to 16.41%. Applying this increase of 2.47% to total 2019 NCSC expenses of $461.1 million, the increase in NCSC expenses allocated to the Company is $11.4 million as a result of the CMA divestiture.

Q. What are the increased NCSC Safety Plan expenses allocated to the Company in the FTY?

A. The Company states that "increase in safety plan expenses relate to the expansion of Columbia's Safety Management (SMS) system." The components of the SMS shown in the response to OCA Data Request I-037 include: Staffing ($3.0 million), Picarro Leak Detection ($0.6 million), Isometric Drawing ($0.7 million) and Pipeline and Hazardous Materials Safety Administration compliance ($0.8 million). Company Witness Kempic further describes the expansion of the SMS in Columbia Statement No. 1.

Q. Has the Company justified the increase in the allocation of NCSC expenses as a result of the CMA sale?

A. The response to OCA Data Request I-037 provides no documentation, workpapers, or other support for the increase in the allocation of NCSC expenses from 13.94% in 2019 to 16.41% in 2021.[3] Further, although the Company stated that "2019 represents the last full year expenses were incurred by Columbia Gas of Massachusetts," the increase in question took place from the HTY, the twelve months ended November 30, 2020, to the FTY, not from 2019 to 2021. In this regard, it is worth noting that the sale of CMA closed in early October 2020, meaning that the HTY already included nearly two months post-sale, and any increase in the allocation ratio from the HTY to the FPFTY should accordingly be less than the increase from calendar 2019 to calendar 2021. In addition, the Company's calculation appears to implicitly assume that that there will be no reduction to the total NCSC expenses as a result of the CMA sale in the two-year period following that sale, an assumption that I find to be questionable.

Finally, there is little evidence that an increase in NCSC costs in the magnitude forecasted by the Company is actually taking place. The response to OCA Data Request VII-014 includes actual NCSC expenses by month for each month of the FTY through April 2021. While the charges in December 2020 were more than forecasted by the Company, the charges in each month of 2021 were consistently and significantly below the amounts forecasted by the Company. The average NCSC

[3] OCA Data Request VIII-05 asked the Company to provide all documentation and workpapers supporting the effect of the CMA sale on the allocation percentages. The response was circular in nature and provided nothing of substance in addition to the response to OCA Data Request I-037.

expense per month budgeted by the Company for the first four months of 2021 is approximately $7.0 million (Exhibit No. 104, Schedule No. 1, Page 5). The actual expense per month for the first four months of 2021 was approximately $5.4 million, which is $1.6 million, or 23%, less.

Q. Assuming it could be established that the sale of CMA does result in an increase in NCSC expenses allocated to the Company, does it follow that such an increase in costs should be included in the Company's revenue requirement and recovered from ratepayers?

A. No. The circumstances of the sale of CMA must be considered.

As described by NiSource Inc., in its 2019 Form 10-K Annual Report filed with the Securities and Exchange Commission:

> On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts (the "Greater Lawrence Incident"). The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality.
>
> NiSource Inc. 2019 Form 10-K, Page 111

Further, as a result of the Greater Lawrence Incident (also referred to as the Merrimack Valley Incident):

> On February 26, 2020, [NiSource Inc.] and Columbia of Massachusetts entered into agreements with the U.S. Attorney's Office to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident. Columbia of Massachusetts agreed to plead guilty in the United States District Court for the District of Massachusetts (the "Court") to violating the Natural Gas Pipeline Safety Act (the "Plea Agreement"), and the Company entered into a DPA [Deferred Prosecution Agreement].

> Under the Plea Agreement, which must be approved by the Court, Columbia of Massachusetts will be subject to the following terms, among others: (i) a criminal fine in the amount of $53,030,116 paid within 30 days of sentencing; (ii) a three year probationary period that will early terminate upon a sale of Columbia of Massachusetts or a sale of its gas distribution business to a qualified third-party buyer consistent with certain requirements; (iii) compliance with each of the NTSB recommendations stemming from the Greater Lawrence Incident; and (iv) employment of an in-house monitor during the term of the probationary period.
>
> NiSource Inc. 2019 Form 10-K, Page 113

On February 26, 2020, NiSource and Columbia of Massachusetts entered into an Asset Purchase Agreement with Eversource Energy ("Eversource") for the sale of CMA to Eversource. The sale was approved by the Massachusetts Department of Public Utilities on October 7, 2020, and closed on October 9, 2020.

The sale by NiSource of CMA to Eversource was the direct result of criminal liability for the Merrimack Valley Incident. Thus, the increase in the allocation of NCSC expenses to Columbia Gas of Pennsylvania resulting from the sale of CMA and consequent loss of scale, if any, originated from the criminal liability for the Merrimack Valley Incident. In effect, including any increased allocation of NCSC expenses due to the CMA sale in the Company's revenue requirement would be imposing the derivative cost effects of the criminal responsibility for the Merrimack Valley Incident on customers. In my opinion, this would not be appropriate.

Q. Are the increased NCSC Safety Plan expenses allocated to the Company in the FTY adequately supported?

A. No. There is little support for the increased NCSC Safety Plan expenses. For example, with regard to staffing, which accounts for approximately 60% of the increase, the Company states that "additional headcount of approximately 60 individuals will be added to provide enhanced ongoing safety training, quality assurance and quality control training and operator qualification training. These positions are in the process of being posted, and it is the Company's intention to fill them as quickly as possible." There is no explanation of how the addition of 60 individuals was determined, the assumptions regarding the salaries of those individuals, or the assignment of the costs to Columbia Gas of Pennsylvania. While the Company states that is its intention to fill these positions as quickly as possible, there is no indication of the extent to which these positions are actually being filled, nearly halfway into the FTY.

With regard to the other elements of the increased NCSC Safety Plan expenses, the support is similarly sparse. There is a description of these other expense increases and a dollar amount assigned to those increases. However, there is no documentation or calculations showing how those expense increases were determined.[4]

Q. Did the Company explain the increase in normalized NCSC expense of $3,353,000 from the FTY to the FPFTY?

A. No. There is a brief explanation of part of the increase in the NCSC expense before normalization from the FTY to the FPFTY. The Company shows that increase as being $1,197,000 and presents a brief explanation for $400,000 of that increase. As

[4] OCA Data Request VIII-06 asked the Company to provide all documentation and workpapers supporting each of the "SMS Expenses" comprising the safety plan. The response provided dollar amounts for sub-categories of the categories of SMS expenses shown in the response to OCA Data Request I-037, but there is no support for how those dollar amounts were developed.

far as I can determine, the increase of normalized NCSC expenses from $73,507,000 in the FTY to $76,860,000 in the FPFTY is not explained.

Q. Are you proposing to adjust the NCSC expenses included in the Company's FPFTY revenue requirement?

A. Yes. The Company has not adequately explained or supported the increase in the actual normalized NCSC expense in the HTY to the projected NCSC expense in the FPFTY, especially considering the magnitude of the increases being forecasted.

Q. What do you recommend?

A. The response to OCA Data Request I-037, Attachment A shows the total NCSC expenses increasing from $461.1 million in 2019 to $483.9 million in 2021. This translates into an increase of 2.44% per year over this two year period, which does not seem unreasonable. Therefore, I am proposing to calculate the NCSC expense for the FPFTY by escalating the actual normalized NCSC expense for the HTY by 2.44% per year.

Q. What is the effect of using your proposed method to project the NCSC expense for the FPFTY?

A. The effect is to reduce the NCSC expense included in FPFTY operation and maintenance expense by $14,959,000 (my Schedule C-1.2).

g. Safety Management Systems

Q. Did the Company adjust FPFTY expenses for Safety Management System ("SMS") costs?

A. Yes. On Exhibit No.104, Schedule 2, Page 19, there is an adjustment of $250,000 for SMS expenses in the FPFTY.

Q. Are you proposing to modify that adjustment?

A. Yes. In OCA Data Request I-44, the Company was asked to provide documentation supporting this adjustment. The Company provided calculations supporting $20,000 of this adjustment, which is related to the cost of tags. The remaining $230,000 was described as being "used to purchase replacement parts to have on hand in the event of equipment failure." There was no documentation or calculations supporting this $230,000. Further, based on the Company's description, it appears that that the cost of the replacement parts is more properly charged to inventory than to expense. Accordingly, I am proposing to eliminate this $230,000 item from pro forma FPFTY expenses (my Schedule C-1).

2. DEPRECIATION AND AMORTIZATION

Q. Have you reflected an adjustment to the FPFTY depreciation expense in your calculation of pro forma operating income under present rates?

A. Yes. Consistent with my adjustment to FPFTY plant in service, I am proposing to adjust the Company's FPFTY depreciation expense. My adjustment to depreciation expense is shown on my Schedule C-2.

Q. Are you proposing any other adjustments to the depreciation and amortization expenses included in the FPFTY revenue requirement?

A. Yes. I am proposing to adjust the plant amortization as shown on Company Exhibit 109, Page 9. My proposed adjustments apply to the amortization of Account 303 – Miscellaneous Intangible Plant and the amortization of Account 375.71 – Structures and Improvements – Leased.

Q. Please describe your proposed adjustment to the amortization of Account 303 – Miscellaneous Intangible Plant.

A. The balance of Miscellaneous Intangible Plant as of the end of the HTY was $32.5 million, and the amortization of that plant was $4.1 million. As of the end of the FTY, the balance had decreased slightly to $32.3 million, but the amortization for the FTY increased to $5.8 million. For the FPFTY, the forecasted balance is $41.5 million, and the forecasted amortization is $8.0 million. Thus, while the plant balance increases by approximately 28% from the HTY to the FPFTY, the amortization increases by approximately 95%.

OCA Data Request VIII-001 asked the Company to provide all workpapers supporting the FTY amortization and an explanation of the increase in the amortization from the HTY to the FTY. OCA Data Request VIII-002 asked the Company to provide all workpapers supporting the FPFTY amortization and an explanation of the increase in the amortization from the FTY to the FPFTY.

The Company responded to OCA Data Request VIII-001 with a narrative explanation of factors that could cause the increase in amortization from the HTY to the FTY. The only numerical support for the FTY amortization was a statement that the FTY amortization is the average of the estimated amortization of $4,886,725 for the December 2020 to November 2021 period and the estimated amortization of $6,697,197 for the December 2021 to November 2022 period. There was no support for the $4,886,725 or for the $6,697,197.

The Company similarly responded to OCA Data Request VIII-002, with a generalized description of the FPFTY amortization and a statement that the FPFTY amortization is the average of the estimated amortization of $6,697,197 for the December 2021 to November 2022 period and the estimated amortization of $9,359,653 for the December 2022 to December 2023 period.[5] Again, there was no support for the $6,697,197 or for the $9,359,653.

Given the magnitude of the increase in the amortization of Miscellaneous Intangible Plant from the HTY to the FPFTY, especially relative to the increase in the plant balance, the Company's explanations are not adequate. I have estimated the FPFTY amortization of Miscellaneous Intangible Plant by beginning with the actual HTY amortization and assuming that the additions from the HTY to the FPFTY would be amortized over five years. This method results in annual amortization of $5,923,000 (my Schedule C-2). This is $2,106,000 less than the FPFTY amortization of $8,028,000 reflected by the Company. Accordingly, I recommend that the

[5] The Company did not specify whether the amortization for the "December 2022 to December 2023 period," includes the amortization of intangible plant additions in 2023. If so, this would obviously not be appropriate to include in the determination of FPFTY amortization.

Company's FPFTY amortization of Miscellaneous Intangible Plant be reduced by $2,106,000.

Q. Please describe your proposed adjustment to the amortization of Account 375.71 – Structures and Improvements – Leased.

A. Referring to Company Exhibit 109, Page 9, it can be seen that net balance (original cost less book reserve, representing the remaining net cost of the plant to be recovered) of Account 375.71 – Structures and Improvements – Leased for the FPFTY is $1,440,000. Yet the annual amortization of this net balance is $2,356,000. OCA Data Request VIII-004 asked the Company to provide all workpapers supporting the amortization and to explain why the FPFTY amortization is greater than "Future Book Accrual" (the original cost less book reserve).

The Company responded to OCA Data Request VIII-004 with a general description of how amortization is calculated and stated that the Account 375.71 – Structures and Improvements amortization amount of $2,355,592 in the FPFTY is the average of the estimated amortization of $2,281,817 for the December 2021 to November 2022 period and the estimated amortization of $2,429,366 for the December 2022 to December 2023 period. The Company also stated that the future accruals reflect the end of the test year period recovery and the annual accruals reflect that annualized amount based on the average. There was no support for the $2,281,817 or for the $2,429,366.

The Company's response does not adequately explain why the FPFTY amortization for this account is greater than the net FPFTY cost of this account remaining to be recovered. I have estimated the FPFTY amortization of Structures and Improvements – Leased by beginning with the actual HTY amortization and assuming that the additions from the HTY to the FPFTY would be amortized over five years. This method results in annual amortization of $397,000 (my Schedule C-2). This is $1,959,000 less than the FPFTY amortization of $2,356,000 reflected by the Company. Accordingly, I recommend that the FPFTY amortization of Structures and Improvements – Leased be reduced by $1,959,000.

Q. Please summarize your proposed adjustments to FPFTY plant amortization.

A. I am proposing to reduce the amortization of Miscellaneous Intangible Plant by $2,106,000 and the amortization of Structures and Improvements – Leased by $1,959,000. I am proposing a total reduction to FPFTY plant amortization of $4,065,000.

3. TAXES OTHER THAN INCOME TAXES

Q. Are you proposing to adjust the pro forma FPFTY year taxes other than income taxes?

A. Yes. Consistent with my adjustments to FPFTY labor expense, I am proposing to adjust payroll taxes. My adjustment to payroll taxes is shown on Schedule C-3.

4. INCOME TAXES

Q. Please explain the calculation of your pro forma adjustments to FPFTY income tax expenses.

A. The calculation of my adjustments to income tax expenses is shown on my Schedule C-4. This schedule shows the adjustments to taxable income from the other adjustments to operating income that I am proposing. I also calculate the adjustment to interest expense (the weighted cost of debt times rate base) resulting from my proposed adjustments to rate base. I apply the effective state income tax rate, after taking account of the use of net operating loss carry-forwards, to the adjustments to taxable income to calculate the adjustment to state income tax expense, and I then apply the federal income tax rate to the adjustments to taxable income net of state income taxes to calculate the adjustment to federal income tax expense.

Q. Does this conclude your direct testimony?

A. Yes.

Appendix 1

RESUME OF DAVID J. EFFRON

UTILITY REGULATION EXPERIENCE

Assistance to offices representing customer interests in Rhode Island, Maryland, Massachusetts, Illinois, and Texas regarding electric utility restructuring matters.

Presentation of testimony on various utility regulation matters involving electric, gas, telephone, and water utilities in the following jurisdictions: Alabama, Arizona, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, Washington, and FERC.

Assistance to attorneys in preparing discovery, cross-examination, post-hearing briefs, and analysis of orders; provision of technical assistance during settlement negotiations.

CABLE CONSULTING EXPERIENCE

Assistance to local franchising authorities in financial feasibility reviews, regulation of cable rates, franchise fee audits, and negotiation of franchise agreements.

OTHER BUSINESS EXPERIENCE

Supervision of capital project analysis, capital budgets, spending reports, leasing program, and special studies; feasibility studies, accounting systems, statistical surveys; audits of publicly held companies in various industries.

EMPLOYMENT HISTORY

Dates	Company
March 1982 - Present	Berkshire Consulting Services (Self-employed)
January 1977 - February 1982	Georgetown Consulting Group
April 1975 - January 1977	Gulf & Western Industries
February 1973 - March 1975	Touche Ross & Company

EDUCATION

Columbia University, MBA, 1973
Dartmouth College, BA Economics, 1968

HONORS AND AWARDS

Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 Certified Public Accounting Examination in New York State.

Graduated from Dartmouth College with distinction in the field of Economics

TABLE I
INCOME SUMMARY
($000)

	Pro Forma Present Rates	Recommended Adjustments	Adjusted Present Rates	Revenue Adjustment	Total Allowable Revenue
Operating Revenue	$ 661,207	$ -	$ 661,207	$ 8,903	$ 670,110
Deductions					
O&M Expense	386,081	(24,904)	361,177	101	361,278
Depreciation	109,970	(6,252)	103,718		103,718
Taxes:					
State	1,276	1,888	3,164	528	3,692
Federal	21,688	6,219	27,907	1,738	29,645
Deferred and ITC	-		-		-
Other	3,716	(141)	3,575	-	3,575
Total Deductions	522,731	(23,188)	499,543	2,366	501,909
					-
Net Income Available for Return	$ 138,476	$ 23,188	$ 161,664	$ 6,537	$ 168,201
Rate Base					$ 2,596,006
Return on Rate Base					6.48%

TABLE II
SUMMARY OF ADJUSTMENTS
($000)

Recommended Adjustment	Exhibit Reference		Rate Base Effect	Revenue Effect	Expense Effect	Depreciation Effect	Effect on Other Taxes	State Tax Effect	Federal Tax Effect
			$	$	$	$	$	$	$
FPFTY Plant Additions	OCA St.1	Sch. B-1, C-2	(82,165)			(2,187)		131	432
Correction to ADIT Balance	OCA St.1	Sch. B-1	1,095						
Labor Expense	OCA St.1	Sch. C-1, C-3		-	(1,163)		(141)	78	257
Employee Benefits Expense	OCA St.1	Sch. C-1			(810)			49	160
Incentive Compensation	OCA St.1	Sch. C-1			(2,776)			166	548
Stock Rewards	OCA St.1	Sch. C-1			(306)			18	60
Outside Services Expense	OCA St.1	Sch. C-1			(4,307)			258	850
Rate Case Expense	OCA St.1	Sch. C-1			(353)			21	70
NCSC Expense	OCA St.1	Sch. C-1			(14,959)			897	2,953
Safety Management Systems	OCA St.1	Sch. C-1	-		(230)			14	45
Plant Amortization	OCA St.1	Sch. C-2	4,065			(4,065)		244	802
Interest Synchronization	OCA St.1	Sch. C-4						12	41
Total Adjustment			(77,006)	-	(24,904)	(6,252)	(141)	1,888	6,219
Company Rate Base	CPA Exh. 108, Page 3		2,673,012						
Recommended Rate Base			2,596,006						

Schedule A

COLUMBIA GAS OF PENNSYLVANIA, INC.
REVENUE DEFICIENCY
($000)

	(1) Company Position	Adjustments		Proposed Position
Measures of Value (Rate Base)	$ 2,673,012	$ (77,006)	(2)	$ 2,596,006
Rate of Return	7.88%	-1.40%	(3)	6.48%
Operating Income Requirement	210,633	(42,432)		168,201
Adjusted Operating Income	138,476	23,188	(4)	161,664
Income Deficiency (Excess)	72,157	(65,621)		6,537
Gross Revenue Conversion Factor	1.3620	-	(5)	1.3620
Revenue Deficiency (Excess)	$ 98,278	$ (89,375)		$ 8,903

Sources:
(1) CPA Exhibit 102, Schedule 3, Page 3
(2) Schedule B
(3) Schedule D
(4) Schedule C
(5) CPA Exhibit 102, Schedule 3, Page 5

Revenue		1.0000
Uncollectible Accounts		0.0114
Pre-Tax Income		0.9886
State Income Tax	5.99%	0.0593
Federal Taxable Income		0.9294
Federal Income Tax	21%	0.1952
Net Income		0.7342
Gross Revenue Conversion Factor		1.3620

COLUMBIA GAS OF PENNSYLVANIA, INC.
MEASURES OF VALUE (RATE BASE)
($000)

	(1) Company Position	Adjustments		Proposed Position
Total Gas Plant	$3,673,219	$ (87,471)	(2)	$3,585,748
Reserve for Accumulated Depreciation	(614,349)	(6,387)	(3)	(607,962)
Net Utility Plant in Service	3,058,870	(81,084)		2,977,786
Working Capital	-			-
Materials and Supplies	1,213			1,213
Prepayments	3,707			3,707
Gas Stored Underground	34,854	-		34,854
Subtotal	39,774	-		39,774
Deduct				
Accumulated Deferred Income Taxes	422,195	(4,079)	(4)	418,116
Customer Deposits	3,456	-		3,456
Customer Advances	(19)	-		(19)
Subtotal	425,632	(4,079)		421,553
Net Measures of Value (Rate Base)	$2,673,012	$ (77,006)		$2,596,006

Sources:

(1)	CPA Exhibit 108, Page 3	
(2)	Schedule B-1	
(3)	Schedule B-1	(2,322)
	Schedule C-2	(4,065)
	Total Adjustment	(6,387)
(4)	Schedule B-1	(2,984)
	OCA I-8	(1,095)
	Total Adjustment	(4,079)

COLUMBIA GAS OF PENNSYLVANIA, INC.
PLANT ADDITIONS
($000)

		2021	2022	Total
Average Plant Additions 2019 - 2020	(1)	286,203	286,203	
Plant Additions, per Company	(2)	335,340	324,536	
Adjustment to Plant in Service		(49,138)	(38,334)	$ (87,471)
Adjustment to Depreciation Reserve	(3)	(614)	(1,708)	(2,322)
Adjustment to ADIT	(4)	(1,897)	(1,087)	(2,984)
Net Rate Base Adjustment				$ (82,165)

Sources:

(1)	Plant Additions 2019	294,610	Exhibit NMS-3, Docket 20203018835
	Plant Additions 2020	277,795	Exhibit NMS-1
	Average	286,203	
(2)	Exhibit 108, Schedule 1		
(3)	Depreciation Rate - Schedule C-2	2.50%	
(4)	CPA Exhibit 108, Schedule 8		
	Assumes change in ADIT is proportional to plant adjustment		

Schedule C

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATING INCOME
($000)

	(1) Company Position	Adjustments		Proposed Position
Sales Revenue	$ 659,933			$ 659,933
Other Operating Revenue	1,274	-		1,274
Operating Revenue	$ 661,207	$ -		$ 661,207
Gas Supply Expense	161,368			161,368
Operation and Maintenance Expense	224,713	(24,904)	(2)	199,809
Depreciation and Amortization	109,970	(6,252)	(3)	103,718
Taxes other than Income Taxes	3,716	(141)	(4)	3,575
State Income Tax Expense	1,276	1,888	(5)	3,164
Federal Income Tax Expense	21,688	6,219	(5)	27,907
				-
Total Operating Expenses	522,731	(23,188)		499,543
Adjusted Operating Income	$ 138,476	$ 23,188		$ 161,664

Sources:
- (1) CPA Exhibit 102, Schedule 3, Page 3
- (2) Schedule C-1
- (3) Schedule C-2
- (4) Schedule C-3
- (5) Schedule C-4

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATION AND MAINTENANCE EXPENSE
($000)

Labor Expense	(1)	$ (1,163)
Employee Benefits Expense	(1)	(306)
Incentive Compensation	(2)	(810)
Stock Rewards	(3)	(2,776)
Outside Services Expense	(4)	(4,307)
Rate Case Expense	(5)	(353)
NCSC Expense	(6)	(14,959)
Safety Management Systems	(7)	(230)
Total Adjustment to Operation and Maintenance Expense		$ (24,904)

Sources:

(1)	Schedule C-1.1	
(2)	I&E RE-017-D, SDR GAS-RR-026	1566/38012*39678-2445
(3)	Response to OCA I-25	(559+2217)
(4)	Schedule C-1.2	
(5)	CPA Exhibit 104, Schedule 2, Page 16	1060*2/3-1060
(6)	Schedule C-1.3	
(7)	Response to OCA I-44	

COLUMBIA GAS OF PENNSYLVANIA, INC.
LABOR AND BENEFITS EXPENSE
($000)

Employees April 30, 2021	(1)	771
Public Affairs Specialists	(2)	2
Adjusted Employee Complement April 30, 2021		769
Forecasted FPFTY Employees	(3)	798
Adjustment to Number of Employees		(29)
O&M Labor Expense per Incremental Employee	(4)	$ 37.097
Adjustment to FPFTY Labor Expense for Employee Complement		$ (1,076)
"Other" Labor Adjustments	(5)	(87)
Total Adjustment to FPFTY Labor Expense		$ (1,163)
Other Employee Benefits Expense per Employee	(5)	$ 10.54
Adjustment to FPFTY Employees		(29)
Adjustment to Benefits Expense		$ (306)

Sources:

(1)	Response to OCA VII-13	
(2)	Columbia Statement No. 7, Page 17	
(3)	SDR GAS-RR-026	
(4)	SDR GAS-RR-026	(1957-807)/(47-16)
(5)	SDR GAS-RR-026	457-370
(6)	CPA Exhibit 104, Schedule 1, Page 2	8408/798

COLUMBIA GAS OF PENNSYLVANIA, INC.
OUTSIDE SERVICES EXPENSE
($000)

		Outside Services Expense	(1) Deflator Index to HTY		Escalated Expense
12/17-11/18	(2)	$ 22,319	0.9632		$ 23,171
12/18-11/19	(2)	23,300	0.9803		23,768
Average Escalated to HTY					23,469
Escalation to FTY			(3)	1.64%	23,854
Escalation to FPFTY			(3)	1.85%	24,295
Lobbying Expense			(4)		(165)
Normalized FFPTY Outside Services Expense					24,130
FFPTY Outside Services Expense per Company			(5)		28,437
Adjustment to Company Outside Services Expense					$ (4,307)

Sources:
(1) CPA Exhibit 4, Schedule 2, Page 11
(2) CPA Exhibit 4, Schedule 1, Page 2
(3) CPA Exhibit 104, Schedule 2, Page 20
(4) CPA Exhibit 104, Schedule 2, Page 4
(5) CPA Exhibit 104, Schedule 1, Page 4

COLUMBIA GAS OF PENNSYLVANIA, INC.
NCSC BENEFITS EXPENSE
($000)

Normalized HTY NCSC Expense	(1)	$ 58,867
Escalation of NCSC Expense to FTY	(2)	2.44%
FTY NCSC Expense		60,305
Escalation of NCSC Expense to FPFTY	(3)	2.65%
FPFTY NCSC Expense		61,901
Normalized FPFTY NCSC Expense, per Company	(1)	76,860
Adjustment to FPFTY NCSC Expense		$(14,959)

Sources:

(1) CPA Exhibit 104, Schedule 1, Page 2

(2) Responses to OCA I-37, Attachment A (483.9/461.1)^(1/2)-1

(3) Annual escalation rate * 13/12

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION EXPENSE
($000)

Adjustment to Plant in Service	(1)	$ (87,471)
Composite Depreciation Rate	(2)	2.50%
Adjustment to Depreciation Expense		$ (2,187)

Adjustment to Plant Amortization:

	(3) HTY Amort.	(4) Adds to FPFTY	(5) Amort. of Adds	(6) Total Amort.	(2) Amort per Co.	Adjstmt.
Misc, Intangible Plant	$4,138	$ 8,925	$1,785	$5,923	$ 8,028	$ (2,106)
Struct. & Impr.- Leased	302	474	95	397	2,356	(1,959)
Totals	$4,439	$ 9,399	$1,880	$6,319	$10,384	$ (4,065)

Total Adjustment to Depreciation and Amortization Expense	$ (6,252)

Sources

(1) Schedule B-1
(2) CPA Exhibit 105, Page 9
(3) CPA Exhibit 5, Page 4
(4) CPA Exhibits 105, Page 9; 5 Page 4
(5) Additions to FPFTY/5
(6) HTY Amortization + Amortization of Additions

COLUMBIA GAS OF PENNSYLVANIA, INC.
TAXES OTHER THAN INCOME TAXES
($000)

Adjustment to FPFTY Payroll	(1)	$ (1,973)
Payroll Tax Rate	(2)	7.13%
Adjustment to Payroll Taxes		$ (141)

Sources
(1) Schedule C-1.1
(2) CPA Exhibit 106, Page 3

COLUMBIA GAS OF PENNSYLVANIA, INC.
INCOME TAXES
($000)

Adjustments to Taxable Income:

Revenue	(1)	$ -
Operation and Maintenance Expense	(1)	(24,904)
Depreciation and Amortization	(1)	(6,252)
Taxes other than Income Taxes	(1)	(141)
Interest	(2)	(208)
Adjustment to Expenses		(31,504)
Net Adjustment to Taxable Income		31,504
Effective Pennsylvania Income Tax Rate (Net of NOL)		5.99%
Adjustment to Pennsylvania Income Tax		$ 1,888
Adjustment to Federal Taxable Income		29,616
Federal Income Tax Rate		21%
Net Adjustment to Federal Income Tax		$ 6,219

Sources:

(1)	Schedule C		
(2)	Rate Base	2,596,006	Schedule B
	Weighted Debt Cost	1.98%	Schedule D
	Interest Deduction	51,381	
	Company Interest Deduction	51,589	CPA Exhibit 107, Page 16
	Adjustment	(208)	

Schedule D

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	41.77%	4.54%	1.90%
Short Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	10.95%	5.95%
Total Capital	100.00%		7.88%

OCA Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	42.12%	4.54%	1.91%
Short Term Debt	7.88%	0.85%	0.07%
Common Equity	50.00%	9.00%	4.50%
Total Capital	100.00%		6.48%

Sources: OCA Statement No. 2, Page 5
Testimony of Mr. O'Donnell

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, David J. Effron, hereby state that the facts set forth in my Direct Testimony, OCA Statement 1, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

David J. Effron

DATED: June 16, 2021 Signature: ______________________________

*311182 David J. Effron

Consultant Address: Berkshire Consulting Services
12 Pond Path
North Hampton, NH 03862

OCA Statement No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2021- 3024296**
	:	
Columbia Gas of Pennsylvania, Inc.	**:**	

SURREBUTTAL TESTIMONY OF DAVID J. EFFRON
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

JULY 27, 2021

Introduction

Q. Please state your name and business address.

A. My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire 03862.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted Direct Testimony on June 16, 2021, marked as OCA Statement No. 1. My qualifications and experience are attached to my Direct Testimony.

Q. What is the purpose of this Surrebuttal Testimony?

A. In this Surrebuttal Testimony, I respond to the Rebuttal Testimony of Columbia Gas witnesses Baryenbruch, Brumley, Cartella, Harding, Kempic, Miller, Paloney, Shultz, and Spanos. I am also presenting certain modifications to the adjustments that I proposed in my Direct Testimony and a revised calculation of the Company's revenue deficiency (or excess) to incorporate the effect of those modifications. I do not respond to all of the Company's Rebuttal addressing the issues presented in my Direct Testimony. However, this should not be interpreted to mean that I agree with the Company's Rebuttal on those issues or that I no longer believe that the positions expressed on those issues in my Direct Testimony are appropriate.

Q. With the modifications to the original adjustments proposed in your Direct Testimony, what is the Company's revenue deficiency?

A. Incorporating the modifications that I address in the following Surrebuttal Testimony, I have calculated a revenue deficiency of $12,891,000 (see my revised Schedule A, accompanying this testimony).

Plant Additions

Q. Does the Company agree with your proposal to adjust the forecasted FTY and FPFTY plant additions?

A. No. Company witnesses Brumley, Harding, Kempic, Shultz, and Spanos address my proposed adjustments to the FTY and FPFTY plant additions.

Q. Referring to the Commission's adoption of a similar adjustment that you proposed in the Company's last case, Mr. Kempic states that "Based in large measure on arguments relative to the uncertainty associated with the impact of COVID-19 on the Company's work plans, the Commission adopted a similar adjustment. However, it is inappropriate to do so again."[1] Did the Commission cite "uncertainty associated with the impact of COVID-19" in its disposition of the issue of projected plant additions in Docket No. R-2020-3018835?

A. As far as I can determine, it did not. The impact of COVID-19 in 2020 as compared to the present circumstances is not a relevant consideration in the determination of whether my adjustment should be adopted in the present case.

[1] Company Statement No. 1-R, Page 5.

Q. Mr. Kempic also states that "To again adopt the OCA's plant adjustment in this case would … serve to undermine the intent of the FPFTY."[2] Is this a valid criticism of your proposed adjustment?

A. No. I am not proposing to include the plant as of the end of the HTY or FTY in the Company's rate base. I am only proposing to modify the level of plant additions projected by the Company in the FTY and FPFTY. This in no way undermines the intent of the FPFTY.

Q. Ms. Shultz states that you have "offered no evidence that the Company will not complete its 2021 and 2022 forecasted plant additions."[3] Do you have a response?

A. Yes. As the issue relates to future plant additions, actual evidence of whether the Company completes its 2021 and 2022 forecasted plant additions or not will not exist until the end of 2021 and 2022, respectively. I based my adjustment on the information available at the time of my Direct Testimony.

Q. Mr. Brumley notes that "Columbia witness Nicole Paloney, in Columbia Statement No. 9-R, explains why Mr. Effron's claim that reducing the balance of plant in service in the FPFTY does not impose a risk of under-recovery for the Company is inaccurate."[4] Does Witness Paloney present any such explanation in her Rebuttal Testimony?

[2] Company Statement No. 1-R, Page 7.
[3] Company Statement No. 6-R, Page 6.
[4] Company Statement No. 7-R, Page 8.

A. As far as I can determine, she does not. At Pages 1-4 of her Rebuttal Testimony, she responds to testimony by a witness for another party regarding the availability of the DSIC and how that affects the need to file base rate cases. However, I cannot find anything in her Rebuttal Testimony responding to my testimony that my proposed adjustment to the Company's projection of FPFTY plant poses no risk of under-recovery to the Company.

In my Direct Testimony, I stated that "if my adjustment is accepted and the Company's actual additions are in excess of my proposed plant additions, the Company will be able to recover any such excess through the DSIC."[5] As far as I can determine, neither Mr. Brumley nor Ms. Paloney has presented any testimony to rebut this statement.

Q. Are there are any other matters with regard to the DSIC to be addressed?

A. Yes. I have been advised by counsel that the impact of Act 40 on the treatment of income tax deductions and credits in the DSIC calculation was raised in two cases involving FirstEnergy and Newtown Artesian Water Company. On July 21, 2021, those cases were decided by the Pennsylvania Supreme Court and remanded "to the PUC for the purpose of requiring [those utilities] to revise their tariffs and Distribution System Improvement Charge calculations in accordance with Section 1301.1(a) of the Public Utility Code, 66 Pa. C.S. § 1301.1."[6] Pending the outcome of those proceedings, all necessary changes to the utilities' DSIC calculations and tariffs will need to be addressed in a future filing.

[5] OCA Statement No. 1, Page 8.
[6] *McCloskey v. Pa. PUC*, 2021 Pa. LEXIS 3071, *48.

Q. What criticisms of your proposed adjustment to plant additions does Mr. Spanos present?

A. Mr. Spanos states that he has a number of "concerns" as to how I calculated my recommended adjustments.[7] These concerns relate mainly to my use of net additions rather than gross additions and my use of a composite depreciation rate to calculate the derivative adjustments to depreciation expense and accumulated depreciation related to the adjustment to FPFTY plant in service. He claims that my use of a composite depreciation rate to calculate my adjustments to depreciation expense "fails to recognize that the composite depreciation rate changes as the amount and composition of plant changes."[8]

Q. Has Mr. Spanos indentified any specific problems with your use of net additions in calculating your proposed adjustment to FPFTY plant in service?

A. No. He states that "using net additions is not realistic and averaging net additions levels of prior years under different conditions improperly reduce rate base in his calculations."[9] However, he does not produce any evidence that the use of net additions has biased by adjustment in one direction or the other or that using gross additions would produce a materially different result. My use of net additions does nothing more than assume that retirements in the FTY and FPFTY will be the same as the average of retirements in 2019 and 2020, an assumption that I believe is not unreasonable.

[7] Company Statement No. 5-R, Page 1.
[8] Company Statement No. 5-R, Page 1.
[9] Company Statement No. 5-R, Page 2.

Q. Is your use of a composite depreciation rate to calculate your adjustment to depreciation expense reasonable?

A. Yes. In effect, the use of the composite depreciation rate to calculate the adjustment to depreciation expense implicitly assumes that reductions to plant additions by individual plant account will be roughly proportional to the existing plant balances in the individual plant accounts. I believe that this is a reasonable, and unbiased, assumption for the purpose of calculating the adjustment to depreciation expense associated with the adjustment to plant in service. In fact, Mr. Spanos offers no evidence that my method is biased or results in either an under or overstatement of the adjustment to depreciation expense.

Q. What element of your adjustment to rate base for plant additions does Ms. Harding address?

A. Ms. Harding states that my calculation of the derivative adjustment to accumulated deferred income taxes ("ADIT") is a "high level approach [that] understates the correlating adjustment, or reduction, to ADIT."[10]

Q. Is this a valid point?

A. Yes. Ms. Harding actually presents a detailed calculation of the effect of the plant adjustments on book/tax timing differences and ADIT balances. I agree that her detailed and specific approach is better than my estimating method. Accordingly, I

[10] Company Statement No. 10-R, Page 8.

have increased the reduction to ADIT associated with my plant adjustment to $4,074,000, to reflect the calculation presented by Ms. Harding.

Employee Complement

Q. Ms. Paloney does not agree with your proposed reduction to the FPFTY headcount, but does offer an "alternative" calculation should a reduction in headcount be made.[11] Do you have a response to the alternative calculation presented by Ms. Paloney?

A. Yes. Ms. Paloney states that "should a headcount adjustment be made, the adjustment should be adjusted based on 789 employees, not 769."[12] The headcount of 789 is based on 774 employees as of the end of June 2021, plus 15 applicants that have accepted positions offered. It is not clear when the applicants will actually start work. However, based on Ms. Paloney's description, it appears that the additional 15 employees will be added over time. It is likely other employees will be retiring or leaving as the new employees are added, and it is not clear that the actual employee headcount will reach 789 any time soon. Therefore, I believe that it is more appropriate to base any headcount adjustment on the latest actual employee headcount.

On my Schedule C-1.1 accompanying this Surrebuttal Testimony, I have modified my adjustment using the actual employees as of the end of June as a starting point. I am now proposing to reduce pro forma FPFTY labor expense by $1,019,000

[11] Company Statement No. 9-R, Page 5.
[12] *Id.*

to eliminate the Company's projected increase in headcount from June 2021 to the FPFTY.

Incentive Compensation

Q. Does the Company agree with your proposed adjustment to FPFTY incentive compensation expense?

A. No. Ms. Paloney states that "Incentive Compensation awards are based on many factors," and "[l]ooking at one point in time … does not provide a basis to qualify a projection as unreasonable."[13] This means nothing more than the incentive compensation in a given period might be more or less than in prior periods. However, the Company has still not provided any workpapers or documentation that would establish just how its forecasted FPFTY incentive compensation of $2,445,000 was determined.

Ms. Paloney also asserts that my "proposal reverts to the use of historical ratemaking principles rather than the use of a FPFTY."[14] However, I did not simply propose that the HTY incentive compensation expense be used as the FPFTY expense. Rather, I calculated the ratio of incentive compensation to payroll expense in the normalized HTY expense and applied that ratio to payroll expense in the FPFTY to calculate the FPFTY incentive compensation expense. I believe that this is a reasonable and unbiased method to determine the incentive compensation to be included in the Company's revenue requirement.

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[13] Company Statement No. 9-R, Pages 9-10.
[14] Company Statement No. 9-R, Page 10.

Q. Ms. Paloney also criticizes you for utilizing "the accrued incentive compensation expense, as opposed to the actual payout for incentive compensation expenses, the latter of which more accurately reflects incentive compensation."[15] Do you have a response?

A. Yes. I agree that it would be more accurate to use the actual payout for incentive compensation rather than the accrual for estimated payments. Therefore, I have modified my proposed adjustment to comport with the alternative calculation on page 10 of Ms. Paloney's rebuttal testimony.

Ms. Paloney also presents another alternative that uses a three-year average (ending with the HTY) of incentive compensation as a percentage of labor to project the FPFTY incentive compensation. I agree that it sometimes appropriate to use a multi-year average to determine a normalized level of expense for costs that fluctuate up and down from year to year. However, Ms. Paloney has presented no evidence that her three-year average results in a better representation of the prospective normal compensation expense than does the use of the actual incentive compensation expense for the HTY.

Stock Rewards

Q. Did the Company respond to your testimony regarding the elimination of stock rewards expenses from its revenue requirement?

A. Yes. Ms. Cartella addresses this issue. She states that "Mr. Effron's claim that stock rewards are solely based upon appreciation in stock value is not correct. Stock

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[15] *Id.*

rewards include a variety of metrics…"[16] This misrepresents my testimony. What I stated in my Direct Testimony was "[s]tock rewards are a form of incentive compensation whose ultimate value is based solely on the attainment of financial goals by the parent company."[17] I did not address or characterize the metrics on which stock rewards are based, and my proposed adjustment is not based on the metrics used to determine stock rewards.

Q. Ms. Cartella states that "denial of recovery of stock rewards means that fixed base pay without incentives would become the preferable means to attract, motivate, and retain talented employees while retaining a reasonable opportunity for full recovery of that compensation."[18] Do you have a response?

A. Yes. Ms. Cartella's statement does not establish that stock based compensation is appropriately recoverable from ratepayers. I am not taking the position that stock rewards should not be a component of the employees' total compensation package. The issue is whether it is the customers or shareholders that should bear the cost of the stock rewards program. As shareholders are the beneficiaries of increases to common stock valuations, it is reasonable for shareholders to bear the costs of the stock rewards program.

Outside Services Expense

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[16] Company Statement No. 15-R, Page 5.
[17] OCA Statement No. 1, Page 14.
[18] Company Statement No. 15-R, Page 6.

Q. In her Rebuttal Testimony, does Ms. Paloney provide additional information as support for the Company's projections of FTY and FPFTY outside services expense?

A. Yes. Ms. Paloney presents Exhibit NP-9R, which she describes as "further detail"[19] of the forecasted increases in outside services expense from the HTY to the FTY.

Q. Does Exhibit NP-9R provide any additional documentation or calculations showing how the budgeted expenses for the FTY were actually developed?

A. No. Exhibit NP-9R provides some additional narrative description of the increases in outside services expense from the HTY to the FTY. However, there is no additional documentation or specific calculations showing how the increases in the individual expense categories were developed.

Ms. Paloney states that "[t]he budget for Outside Services is developed reflective of specific needs, plans and the realities of the day to day variability in work and resources."[20] Unfortunately, there is no documentation to establish just how those "specific needs, plans and the realities of the day to day variability in work and resources" translate into the FPFTY outside services expense that the Company is proposing to include in its revenue requirement

Nothing that Ms. Paloney presents changes my recommendation. I continue to believe that my adjustment of $4,307,000 to FPFTY outside services expense is appropriate.

[19] Company Statement No. 9-R, Page 13.
[20] Company Statement No. 9-R, Page 14.

Rate Case Expense

Q. Does the Company agree with your testimony that a normalization period of 1.5 years for rate case costs is reasonable?

A. No. Company Witness Miller states that it is appropriate to use a 12-month period for the purpose of normalizing rate case expense, citing the Company's anticipation of filing rate cases annually for the foreseeable future.[21] However, she does not dispute that my proposed 1.5 year normalization period for rate case expense is an accurate reflection of the Company's actual experience of filing rate cases in recent years. I continue to believe that actual historic experience of the Company's filing frequency is a reasonable basis for determining the period over which to normalize rate case expense.

NCSC Expense

Q. Did the Company respond to your testimony regarding the NCSC expense in the FTY and FPFTY?

A. Yes. Ms. Paloney and Mr. Baryenbruch respond to my testimony on NCSC expense that proposes to reduce the NCSC expense included in the Company's FPFTY revenue requirement by $14,323,000. Ms. Paloney claims that my proposal reverts to "the use of historical ratemaking principles rather than the use of a FPFTY" and "fails to recognize that Columbia Gas of Pennsylvania is still receiving the benefit of services from NiSource Corporate Services at a cost favorable to such services had they been procured outside of the Company."[22] She further states that "a significant

[21] Company Statement No. 4-R, Page 7.
[22] Company Statement No. 9-R, Pages 14-15.

amount of support for the increases related to NCSC expense and safety plan expense has been provided."[23] Mr. Baryenbruch presents testimony that purports to establish that "Columbia's charges from NCSC are reasonable."[24]

Neither Ms. Paloney nor Mr. Baryenbruch has justified the increases in NCSC expense related to the change in allocation ratios or as a result of the other expense increases being forecasted by the Company.

Q. Does your proposed adjustment to NCSC expenses revert to the use of historical ratemaking principles?

A. No. I am not proposing to include the NCSC expense incurred in the test year in the Company's revenue requirement. Rather, I am using the actual expense incurred in the HTY as a basis to project the FPFTY expense. The Company is seeking to include unreasonable and unsupported increases in FPFTY expenses in its revenue requirement. Elimination of such expense increases from the Company's revenue requirement does not constitute reversion to the use of historical ratemaking principles.

Q. Has Ms. Paloney offered any evidence that Columbia Gas of Pennsylvania is receiving the benefit of services from NiSource Corporate Services at a cost favorable to such services had they been procured outside of the Company?

[23]Company Statement No. 9-R, Page 15.
[24] Company Statement No. 16-R, Page 4.

A. No. Based on her testimony at Columbia Statement 9-R, Page 16, Lines 1-4, this conclusion relies on the Rebuttal Testimony of Mr. Baryenbruch. I will address that conclusion in my response to Mr. Baryenbruch.

Q. Ms. Paloney states that the underlying reason for the sale of Columbia Gas of Massachusetts is not relevant to this case.[25] Do you agree?

A. No. Given that the Company is asking its customers to pay approximately $11.4 million in additional NCSC expenses as a result of that sale, I believe it entirely appropriate to examine the underlying reasons for the sale. I described the circumstances of the sale of Columbia Gas of Massachusetts ("CMA") in my Direct Testimony. I continue to believe that it is reasonable to take those circumstances into account in evaluating the reasonableness of the increases in NCSC expense being projected by the Company.

Q. Ms. Paloney claims that "the Company's response to OCA 1-37 … clearly shows how the increases in allocation factors were calculated."[26] Are you able to find where the referenced response shows how the increases in allocation factors were calculated?

A. No. Ms. Paloney attaches the response to OCA 1-37 to her rebuttal testimony as Exhibit NP-5R. On Page 4 of that exhibit, the "2019 Mgmt Allocation" is shown as 13.94% and the "2021 Mgmt Allocation" is shown as 16.41%. The difference between these two is 2.47%. This is the totality of the support for the "increases in

[25] Company Statement No. 9-R, Page 16.
[26] Company Statement No. 9-R, Page 16.

allocation factors." There are no supporting workpapers or calculations for the 2021 Mgmt Allocation" of 16.41%. I do not consider this to be a clear showing of how the increases in allocation factors were calculated.

Q. Is Ms. Paloney's contention that you seek to "support a disallowance of Columbia's budgeted corporate service charges based solely on 5-months of actual data"[27] accurate?

A. No. This is a gross misrepresentation of my testimony. I did cite the actual NCSC expenses in comparison to the Company's forecast for the first five months in 2021 in my Direct Testimony. However my proposed adjustment to NCSC expenses is not based "solely," or even primarily, on those five months of actual data, and that is clear from my testimony.

The claim by Ms. Paloney that "Mr. Effron seeks to support his proposed disallowance based upon a monthly run rate calculation that takes the average of the first 5 months of actual data and extrapolating that through November 2021"[28] is particularly spurious. I did not even present a calculation extrapolating the first 5 months of actual data through November 2021, let alone seek to support my proposed adjustment based on such an extrapolation.

[27] Company Statement No. 9-R, Page 17.
[28] *Id.*

Q. Ms. Paloney asserts that "the Company's response to data request OCA 8-6 … clearly provides the information requested by Witness Effron"[29] with regard to the increase to NCSC Safety Plan expenses. Do you agree?

A. No. OCA Data Request VIII-06 was a follow-up request to OCA Data Request I-37. I referred to the response to OCA Data Request VIII-06 in my Direct Testimony. As I noted there, "The response provided dollar amounts for sub-categories of the categories of SMS expenses shown in the response to OCA Data Request I-037, but there is no support for how those dollar amounts were developed."[30]

Ms. Paloney attaches an "update to the Company's response to OCA 8-6"[31] as Exhibit NP-11R to her rebuttal testimony. She states that "Exhibit 11-R provides additional detail to contradict the notion in Witness Effron's testimony that increased costs for safety initiatives have not been supported."[32] Exhibit 11-R does provide additional narrative description of the increased NCSC Safety Plan expenses. However, there is still no documentation or calculations to support how the specific dollar amounts for those expense increases were developed.

Q. Mr. Baryenbruch begins his response to your testimony on NCSC expenses with a summary of the increase in NCSC expense from the HTY to the FPFTY. Is his summary an accurate comparison?

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[29] Company Statement No. 9-R, Page 19.
[30] OCA Statement 1, Page 25, fn. 4.
[31] Company Statement No. 9-R, Page 19.
[32] *Id.*

A. No. He states that "From the HTY to the FPFTY, NCSC O&M charges increase by approximately $14.5 million."[33] The increase referenced by Mr. Baryenbruch appears to compare NCSC expenses in the HTY *before* normalization adjustments ($62,365,898) to NCSC expenses in the FPFTY *after* normalization adjustments. A more proper comparison would be normalized NCSC expenses in the HTY to normalized NCSC expenses in the FPFTY. As can be seen on Company Exhibit 104, Schedule 1, Page 2, the normalized NCSC expenses increase from $58,867,000 in the HTY to $76,860,000 in the FPFTY. This represents an increase of approximately $18.0 million, or about 24% more than the increase cited Mr. Baryenbruch.

Q. How does Mr. Baryenbruch attempt to establish that Columbia's charges from NCSC are reasonable?

A. He compares "NCSC's charges to Columbia to similar charges of other utilities." He performs "two cost comparisons: (1) service company Administrative and General (A&G) charges per customer and (2) total A&G expenses (both incurred by the utility and allocated from a service company affiliate) per customer."[34]

Q. Please describe Mr. Baryenbruch's comparison of service company A&G charges per customer.

A. Mr. Baryenbruch compares the NCSC A&G expenses costs allocated to the Company to service company A&G charges per customer for 21 other utility holding companies. He calculates the costs per customer for 2020 and then adjusts the

[33] Company Statement No. 16-R, Page 4.
[34] Company Statement No. 16-R, Page 5.

Company's costs for the divestiture of CMA; and then escalates the expenses of the comparison group to 2021 (using the escalation factor of 2.44% referenced in my testimony). He summarizes the comparison in a graph that "shows Columbia's average of $153 in post-divestiture NCSC A&G charges per customer to be somewhat higher than the comparison group average $130. Eight companies, 38% of the comparison group, have a higher cost per-customer than Columbia."[35] Mr. Baryenbruch appears to take this as evidence that the NCSC charges to the Company are reasonable.

Q. Does this comparison of service company A&G expenses establish the reasonableness of the NCSC expenses included by the Company in its FPFTY revenue requirement?

A. No. As a general matter, Mr. Baryenbruch has presented no evidence that he has attempted to weigh or analyze the extent to which the utilities in the comparison group rely on the service company for A&G services (as opposed to incurring the A&G expenses in house) as compared to the extent to which Columbia relies on NCSC for A&G services. He, in effect, appears to implicitly acknowledge this problem when he explains why he also compares total A&G per customer by noting that "there are considerable economies of scale derived from centralizing the management of corporate (i.e., A&G) services such as information technology, finance and human resources."[36] Obviously, the more a utility holding company centralizes the management of corporate services by having such services performed

[35] Company Statement No. 16-R, Pages 8-9.
[36] Company Statement No. 16-R, Page 5.

by the service company, the higher the service company expenses will be. In effect, the comparison of service company expenses per customer penalizes utilities for taking greater advantage of the "considerable economies of scale derived from centralizing the management of corporate (i.e., A&G) services."

More particularly, I do not believe that his comparison of Columbia NCSC expenses adjusted for the CMA divestiture to the comparison group's 2020 service company expenses escalated to 2021 is appropriate. This comparison escalates the comparison group's service company expenses to 2021 but implicitly assumes that there will be no escalation of Columbia's 2020 NCSC expenses other than the increase in the proportion of total NCSC expenses allocated to Columbia as a result of the divestiture of CMA. This is obviously not realistic. In fact, the Company forecasts an increase in NCSC charges to the Company from the HTY to the FTY well in excess of the 2.44% escalation rate, even exclusive of the effect of the divesture of CMA.

If Mr. Baryenbruch is seeking to isolate the effect of the CMA divestiture on the reasonableness of NCSC expenses allocated to the Company, a better comparison would be the 2020 NCSC expenses adjusted for the CMA divestiture to the 2020 service company expenses for the comparison group without escalation. By Mr. Baryenbruch's calculations, the 2020 NCSC A&G expenses adjusted for the CMA divestiture allocated to the Company come to $153 per customer. This is $26, or 20%, greater than the comparison group's 2020 service company A&G expense of $127 per customer. I am not claiming that this proves that NCSC expenses allocated to the Company are unreasonable, but I don't see it as conclusive evidence that NCSC post-divestiture charges to the Company are reasonable either.

Further, Mr. Baryenbruch ignores increases in NCSC charges from the HTY to the FTY other than the increase resulting from the divestiture of CMA in his analysis. He does not even address increases from the FTY to the FPFTY, and he offers no opinion as to the reasonableness of the NCSC expenses included in the Company's FPFTY revenue requirement.

Q. Does Mr. Baryenbruch's comparison of total A&G expenses provide any substantive support for the reasonableness of NCSC charges?

A. No. This comparison includes significant expenses that distort the cost comparison and are completely irrelevant to the reasonableness of NCSC expenses. Mr. Baryenbruch not only includes Accounts 920 – 935, which the FERC Uniform System of Account defines as Administrative and General Expenses, in his comparison, but he also includes Accounts 900 - 916, which contain Customer Accounts Expenses, Customer Service and Informational Expenses, and Sales Expenses in his comparison.

Included in Accounts 900 – 916 is Account 908 – Customer Assistance Expenses. Many utilities include the cost of their Energy Efficiency programs in Account 908. For example, the largest company in the comparison group, Consolidated Edison Company (Con Ed), charged $344 million to Account 908 in 2020. This accounted for approximately 30% of the total A&G, as defined by Mr. Baryenbruch, for Con Ed. Niagara Mohawk Power Corporation, the second largest utility by A&G in the comparison group, charged $306 million, or approximately 45% of total A&G, to Account 908. By contrast, Baltimore Gas and Electric Company ("BGE"), one of the larger companies by customer count in the comparison group, charged a relatively negligible $0.3 million to Account 908. The reason for this is not an absence of Energy Efficiency programs for BGE, but rather that BGE accounts for its Energy Efficiency programs differently.

As an example of how the inclusion of Account 908 in total A&G can affect the cost comparison, on my Schedule C-1.3A, I show the A&G per customer excluding Account 908 for Con Ed and Columbia. In Mr. Baryenbruch's cost comparison, the A&G for Con Ed in 2020 was $321 per customer, about 14% higher than Columbia's cost per customer of $282 (before adjustment for the divestiture of CMA). After the elimination of Account 908, Con Ed's A&G per customer is $223, and Columbia's A&G is $278, which is 25% higher than Con Ed's.

This comparison does not prove that Columbia's A&G expenses are excessive. However, it illustrates the problems in conducting a comparison like Mr. Baryenbruch's without analyzing the causes for different expense levels. There are numerous other expenses in Accounts 900 - 935 in addition to Account 908 that are completely irrelevant to the reasonableness of NCSC costs allocated to Columbia. Yet Mr. Baryenbruch has not eliminated those expenses in his comparison of Columbia's A&G costs to the A&G costs incurred by the comparison group.

Q. Mr. Baryenbruch claims that your "recommended disallowance appears to be based strictly on [your] personal opinion that Columbia's NCSC charges should

only increase by historical escalation rates."[37] Is this a fair reading of your testimony?

A. No. My recommended adjustment is based primarily on the fact that the Company has not adequately supported the increases in NCSC charges from the HTY to the FPFTY, especially given the magnitude of those increases. This is abundantly clear from pages 20 – 26 of my Direct Testimony. The reason I used the cited escalation rates to project Columbia's NCSC expense to the FPFTY is that the Company had not adequately substantiated the increases that it is forecasting, and it has still not done so. Indeed, Mr. Baryenbruch's reference to my supposed reliance on "historical" escalation rates is not even accurate, as my escalation rates are based on the Company's forecasted increase in total service company costs (before allocation) from 2019 to 2021, not "historical" rates.

Q. Mr. Baryenbruch concludes his cost comparison analysis by stating that you make "no attempt to benchmark NCSC's costs to substantiate [your] disallowance."[38] Is he correct?

A. Yes. I did not attempt to benchmark NCSC's costs. I did not do so because I do not believe that a comparison of Columbia's service company costs or A&G expenses per customer to those of other utilities is in any way relevant to a determination of whether a particular proposed adjustment to Columbia's expenses is appropriate or not. Even if we assume that Mr. Baryenbruch is correct that there are a few other utilities out there with higher service company costs and/or A&G expenses per

[37] Company Statement No. 10-R, Page 12.
[38] *Id.*

customer, that in no way justifies or supports the increases in NCSC expenses that the Company is forecasting for the FTY and FPFTY.

Safety Management Systems

Q. Does the Company agree with your adjustment to eliminate $230,000 for purchase of replacement parts to have on hand in the event of equipment failure?

A. No. Company Witness Paloney explains why the Company needs to have such replacement parts available and states that "Even if such costs were considered to be inventory, they would ultimately be expensed upon usage."[39]

Q. Are you modifying your proposed adjustment based on that testimony?

A. No. The Company has still provided no documentation or calculations supporting its proposed adjustment of $230,000. Ms. Paloney's testimony that these parts "would ultimately be expensed upon usage" provides no evidence that such expensing upon usage will actually take place in the FPFTY.

Plant Amortization

Q. Did the Company respond to your testimony proposed adjustments to plant amortization?

A. Yes. Mr. Spanos addresses this issue at pages 4-7 of his rebuttal testimony. With regard to the amortization of Account 303 – Miscellaneous Intangible Plant, he states that "the assets in Account 303 are individually amortized and annual expense is not

[39] Company Statement No. 9-R, Page 20.

consistent from year to year. Additionally, using net plant does not reflect the actual individual applications that are retired and the new assets added with unique amortization periods. The assets in Account 303 are not subject to group depreciation and average life characteristics so it is not reasonable to merely add five year averages to the current levels of expense."[40]

Q. Has Mr. Spanos established that your proposed adjustment to the amortization of Account 303 – Miscellaneous Intangible Plant is incorrect?

A. No. He cites factors that *could*, in theory, cause the prospective amortization of Account 303 to be greater than the amortization that I have calculated. However, he has provided no supporting documentation, workpapers, or calculations to establish that those factors will actually cause the FPFTY amortization to *be* greater.

For example, he states that "the new additions in most cases have an amortization period of 5 years so a substantial increase in annual expense for the summation of all assets in Account 303 should be expected." Yet, he provides no documentation or calculations that actually quantify the amortization associated with those new additions.

OCA Data Request VIII-002 asked the Company to "provide all workpapers supporting the FPFTY Account 303 – Miscellaneous Intangible Plant amortization." The only support for the FPFTY amortization presented by the Company in response was a statement that the FPFTY amortization is the average of the estimated amortization of $6,697,197 for the December 2021 to November 2022 period and the estimated amortization of $9,359,653 for the December 2022 to December 2023

[40] Company Statement No. 5-R, Page 6.

period. Mr. Spanos appears to take the position that the FPFTY amortization should reflect the amortization on the plant as of November 30, 2022. However, based on the response to OCA Data Request VIII-002, the Company's FPFTY amortization expense for Account 303 does not incorporate the method advocated by Mr. Spanos.

Q. Does Mr. Spanos agree with your proposed adjustment to the amortization of Account 375.71 – Structures and Improvements – Leased?

A. No. However, he acknowledges that the FPFTY amortization of Account 375.71 reflected in the Company's direct case is incorrect and presents a revised amortization amount.[41] The revised amount reduces the annual expense by $1,791,000 for the fully projected future test year,[42] from to $2,355,000 to $564,000. The revised FPFTY amortization of Account 375.71 does not seem unreasonable, and it is incorporated in the Company's updated FPFTY amortization expense on Exhibit KKM-1R. Therefore, I am no longer proposing an adjustment to the FPFTY amortization of Account 375.71.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

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[41] Company Statement No. 5-R, Pages 6-7.

[42] *Id.*

TABLE I
INCOME SUMMARY
($000)

	Pro Forma Present Rates	Recommended Adjustments	Adjusted Present Rates	Revenue Adjustment	Total Allowable Revenue
Operating Revenue	$ 661,266	$ -	$ 661,266	$ 12,891	$ 674,157
Deductions					
O&M Expense	385,384	(24,246)	361,138	166	361,305
Depreciation	108,179	(4,293)	103,886		103,886
Taxes:					
State	1,411	1,515	2,926	763	3,688
Federal	22,134	4,989	27,123	2,512	29,635
Deferred and ITC	-		-		-
Other	3,716	(131)	3,585	-	3,585
Total Deductions	520,824	(22,166)	498,658	3,441	502,099
					-
Net Income Available for Return	$ 140,442	$ 22,166	$ 162,608	$ 9,450	$ 172,058
Rate Base					$ 2,595,138
Return on Rate Base					6.63%

TABLE II
SUMMARY OF ADJUSTMENTS
($000)

Recommended Adjustment	Exhibit Reference		Rate Base Effect	Revenue Effect	Expense Effect	Depreciation Effect	Effect on Other Taxes	State Tax Effect	Federal Tax Effect
			$	$	$	$	$	$	$
FPFTY Plant Additions	OCA St.1	Sch. B-1, C-2	(81,075)			(2,187)		131	432
Correction to ADIT Balance	OCA St.1	Sch. B-1	-						
Labor Expense	OCA St.1	Sch. C-1, C-3		-	(1,106)		(131)	74	244
Employee Benefits Expense	OCA St.1	Sch. C-1			(739)			44	146
Incentive Compensation	OCA St.1	Sch. C-1			(2,776)			166	548
Stock Rewards	OCA St.1	Sch. C-1			(411)			25	81
Outside Services Expense	OCA St.1	Sch. C-1			(4,307)			258	850
Rate Case Expense	OCA St.1	Sch. C-1			(353)			21	70
NCSC Expense	OCA St.1	Sch. C-1			(14,323)			859	2,828
Safety Management Systems	OCA St.1	Sch. C-1	-		(230)			14	45
Plant Amortization	OCA St.1	Sch. C-2	2,106			(2,106)		126	416
Interest Synchronization	OCA St.1	Sch. C-4						(204)	(671)
Total Adjustment			(78,969)	-	(24,246)	(4,293)	(131)	1,515	4,989
Company Rate Base	CPA Exh. 108, Page 3		2,674,107						
Recommended Rate Base			2,595,138						

Schedule A

COLUMBIA GAS OF PENNSYLVANIA, INC.
REVENUE DEFICIENCY
($000)

	(1) Company Position	Adjustments		Proposed Position
Measures of Value (Rate Base)	$ 2,674,107	$ (78,969)	(2)	$ 2,595,138
Rate of Return	7.89%	-1.26%	(3)	6.63%
Operating Income Requirement	210,987	(38,929)		172,058
Adjusted Operating Income	140,442	22,166	(4)	162,608
Income Deficiency (Excess)	70,545	(61,095)		9,450
Gross Revenue Conversion Factor	1.3642	-	(5)	1.3642
Revenue Deficiency (Excess)	$ 96,234	$ (83,343)		$ 12,891

Sources:
(1) Exhbit KKM-1R, Page 1
(2) Schedule B
(3) Schedule D
(4) Schedule C
(5) Exhbit KKM-1R, Page 3

Revenue		1.0000
Uncollectible Accounts		0.0129
Pre-Tax Income		0.9871
State Income Tax	5.994%	0.0592
Federal Taxable Income		0.9279
Federal Income Tax	21%	0.1949
Net Income		0.7331
Gross Revenue Conversion Factor		1.3642

Schedule B

COLUMBIA GAS OF PENNSYLVANIA, INC.
MEASURES OF VALUE (RATE BASE)
($000)

	(1) Company Position	Adjustments		Proposed Position
Total Gas Plant	$3,673,219	$ (87,471)	(2)	$3,585,748
Reserve for Accumulated Depreciation	(614,349)	(4,428)	(3)	(609,921)
Net Utility Plant in Service	3,058,870	(83,043)		2,975,827
Working Capital	-			-
Materials and Supplies	1,213			1,213
Prepayments	3,707			3,707
Gas Stored Underground	34,854	-		34,854
Subtotal	39,774	-		39,774
Deduct				
Accumulated Deferred Income Taxes	421,100	(4,074)	(4)	417,026
Customer Deposits	3,456	-		3,456
Customer Advances	(19)	-		(19)
Subtotal	424,537	(4,074)		420,463
Net Measures of Value (Rate Base)	$2,674,107	$ (78,969)		$2,595,138

Sources:

(1)	Exhibit NMS-2, Page 1	
(2)	Schedule B-1	
(3)	Schedule B-1	(2,322)
	Schedule C-2	(2,106)
	Total Adjustment	(4,428)
(4)	Schedule B-1	(4,074)
	OCA I-8 (Corrected in Company Rebuttal)	-
	Total Adjustment	(4,074)

COLUMBIA GAS OF PENNSYLVANIA, INC.
PLANT ADDITIONS
($000)

		2021	2022	Total
Average Plant Additions 2019 - 2020	(1)	286,203	286,203	
Plant Additions, per Company	(2)	335,340	324,536	
Adjustment to Plant in Service		(49,138)	(38,334)	$ (87,471)
Adjustment to Depreciation Reserve	(3)	(614)	(1,708)	(2,322)
Adjustment to ADIT	(4)			(4,074)
Net Rate Base Adjustment				$ (81,075)

Sources:

(1)	Plant Additions 2019	294,610	Exhibit NMS-3, Docket 20203018835
	Plant Additions 2020	277,795	Exhibit NMS-1
	Average	286,203	
(2)	Exhibit 108, Schedule 1		
(3)	Depreciation Rate - Schedule C-2		2.50%
(4)	Exhibit JH-1R		

Schedule C

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATING INCOME
($000)

	(1) Company Position	Adjustments		Proposed Position
Sales Revenue	$ 659,933			$ 659,933
Other Operating Revenue	1,333	-		1,333
Operating Revenue	$ 661,266	$ -		$ 661,266
Gas Supply Expense	161,368			161,368
Operation and Maintenance Expense	224,016	(24,246)	(2)	199,770
Depreciation and Amortization	108,179	(4,293)	(3)	103,886
Taxes other than Income Taxes	3,716	(131)	(4)	3,585
State Income Tax Expense	1,411	1,515	(5)	2,926
Federal Income Tax Expense	22,134	4,989	(5)	27,123
				-
Total Operating Expenses	520,824	(22,166)		498,658
Adjusted Operating Income	$ 140,442	$ 22,166		$ 162,608

Sources:
(1) Exhibit KKM-1R, Page 1
(2) Schedule C-1
(3) Schedule C-2
(4) Schedule C-3
(5) Schedule C-4

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATION AND MAINTENANCE EXPENSE
($000)

Labor Expense	(1)	$ (1,106)
Employee Benefits Expense	(1)	(411)
Incentive Compensation	(2)	(739)
Stock Rewards	(3)	(2,776)
Outside Services Expense	(4)	(4,307)
Rate Case Expense	(5)	(353)
NCSC Expense	(6)	(14,323)
Safety Management Systems	(7)	(230)
Total Adjustment to Operation and Maintenance Expense		$ (24,246)

Sources:

(1) Schedule C-1.1
(2) Columbia Statement No. 9-R, Page 10
(3) Response to OCA I-25 (559+2217)
(4) Schedule C-1.2
(5) CPA Exhibit 104, Schedule 2, Page 16 1060*2/3-1060
(6) Schedule C-1.3
(7) Response to OCA I-44

COLUMBIA GAS OF PENNSYLVANIA, INC.
LABOR AND BENEFITS EXPENSE
($000)

Employees as of June 30, 2021	(1)	774
Public Affairs Specialists	(2)	2
Adjusted Employee Complement April 30, 2021		772
Forecasted FPFTY Employees	(3)	811
Adjustment to Number of Employees		(39)
O&M Labor Expense per Incremental Employee	(4)	$ 26.136
Adjustment to FPFTY Labor Expense for Employee Complement		$ (1,019)
"Other" Labor Adjustments	(5)	(87)
Total Adjustment to FPFTY Labor Expense		$ (1,106)

Other Employee Benefits Expense per Employee	(5)	$ 10.54
Adjustment to FPFTY Employees		(39)
Adjustment to Benefits Expense		$ (411)

Sources:

(1)	Columbia Statement No. 9-R, Page 5	
(2)	Columbia Statement No. 7, Page 17	
(3)	Exhibit NP-2R	
(4)	Exhibit NP-2R	(1957-807)/(47-3)
(5)	Exhibit NP-2R	457-370
(6)	CPA Exhibit 104, Schedule 1, Page 2	8408/798

COLUMBIA GAS OF PENNSYLVANIA, INC.
OUTSIDE SERVICES EXPENSE
($000)

		Outside Services Expense	(1) Deflator Index to HTY		Escalated Expense
12/17-11/18	(2)	$ 22,319	0.9632		$ 23,171
12/18-11/19	(2)	23,300	0.9803		23,768
Average Escalated to HTY					23,469
Escalation to FTY			(3)	1.64%	23,854
Escalation to FPFTY			(3)	1.85%	24,295
Lobbying Expense			(4)		(165)
Normalized FPFTY Outside Services Expense					24,130
FPFTY Outside Services Expense per Company			(5)		28,437
Adjustment to Company Outside Services Expense					$ (4,307)

Sources:
- (1) CPA Exhibit 4, Schedule 2, Page 11
- (2) CPA Exhibit 4, Schedule 1, Page 2
- (3) CPA Exhibit 104, Schedule 2, Page 20
- (4) CPA Exhibit 104, Schedule 2, Page 4
- (5) CPA Exhibit 104, Schedule 1, Page 4

Schedule C-1.3

COLUMBIA GAS OF PENNSYLVANIA, INC.
NCSC EXPENSE
($000)

Normalized HTY NCSC Expense	(1)	$ 58,867
Escalation of NCSC Expense to FTY	(2)	2.44%
FTY NCSC Expense		60,305
Escalation of NCSC Expense to FPFTY	(3)	2.65%
FPFTY NCSC Expense		61,901
Normalized FPFTY NCSC Expense, per Company	(1)	76,224
Adjustment to FPFTY NCSC Expense		$(14,323)

Sources:

(1)	CPA Exhibit 104, Schedule 1, Page 2	76,860
	Exhibit NP-11R	(636)
	Revised Normalized Expense	76,224
(2)	Responses to OCA I-37, Attachment A	(483.9/461.1)^(1/2)-1
(3)	Annual escalation rate * 13/12	

COLUMBIA GAS OF PENNSYLVANIA, INC.
NCSC EXPENSE COMPARISON
($000)

		Con Ed	Columbia
Total A&G Expense *	(1)	1,127,309	124,279
Account 908 Expense	(1)	343,833	3,446
Total A&G Expense Excluding Account 908		783,476	120,833
Customers (000)	(2)	3,517	441
A&G Excluding Account 908 per Customer		$ 223	$ 274

* Includes Accounts 900 - 935

Sources
(1) 2020 FERC Form 1, Schedule PLB - 3
(2) Columbia Statement No. 16-R, Pages 10 - 11

Schedule C-2

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION EXPENSE
($000)

Adjustment to Plant in Service	(1)	$ (87,471)
Composite Depreciation Rate	(2)	2.50%
Adjustment to Depreciation Expense		$ (2,187)

Adjustment to Plant Amortization:

	(3) HTY Amort.	(4) Adds to FPFTY	(5) Amort. of Adds	(6) Total Amort.	(2) Amort per Co.	Adjstmt.
Misc. Intangible Plant	$4,138	$ 8,925	$1,785	$5,923	$ 8,028	$ (2,106)
Struct. & Impr.- Leased	-	-	-	-	-	-
Totals	$4,138	$ 8,925	$1,785	$5,923	$ 8,028	$ (2,106)

Total Adjustment to Depreciation and Amortization Expense	$ (4,293)

Sources
- (1) Schedule B-1
- (2) CPA Exhibit 105, Page 9
- (3) CPA Exhibit 5, Page 4
- (4) CPA Exhibits 105, Page 9; 5 Page 4
- (5) Additions to FPFTY/5
- (6) HTY Amortization + Amortization of Additions

COLUMBIA GAS OF PENNSYLVANIA, INC.
TAXES OTHER THAN INCOME TAXES
($000)

Adjustment to FPFTY Payroll	(1)	$ (1,845)
Payroll Tax Rate	(2)	7.13%
Adjustment to Payroll Taxes		$ (131)

Sources
- (1) Schedule C-1.1
- (2) CPA Exhibit 106, Page 3

Schedule C-4

COLUMBIA GAS OF PENNSYLVANIA, INC.
INCOME TAXES
($000)

Adjustments to Taxable Income:

Revenue	(1)	$ -
Operation and Maintenance Expense	(1)	(24,246)
Depreciation and Amortization	(1)	(4,293)
Taxes other than Income Taxes	(1)	(131)
Interest	(2)	3,398
Adjustment to Expenses		(25,271)
Net Adjustment to Taxable Income		25,271
Effective Pennsylvania Income Tax Rate (Net of NOL)		5.99%
Adjustment to Pennsylvania Income Tax		$ 1,515
Adjustment to Federal Taxable Income		23,756
Federal Income Tax Rate		21%
Net Adjustment to Federal Income Tax		$ 4,989

Sources:

(1)	Schedule C		
(2)	Rate Base	2,595,138	Schedule B
	Weighted Debt Cost	2.13%	Schedule D
	Interest Deduction	55,276	
	Company Interest Deduction	51,878	Exhibit KKM-1R, Page 1
	Adjustment	3,398	

Schedule D

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	41.77%	4.58%	1.91%
Short Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	10.95%	5.95%
Total Capital	100.00%		7.89%

OCA Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	45.74%	4.58%	2.09%
Short Term Debt	4.26%	0.85%	0.04%
Common Equity	50.00%	9.00%	4.50%
Total Capital	100.00%		6.63%

Sources: CPA Exhibit 400R, Page 2
Testimony of Mr. O'Donnell

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, David J. Effron, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 1-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

David J. Effron

DATED: July 27, 2021
*314207

Signature: ______________________________
David J. Effron

Consultant Address: Berkshire Consulting Services
12 Pond Path
North Hampton, NH 03862

OCA Statement No. 2

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2021-3024296**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

DIRECT TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

June 16, 2021

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (“OCA”). The OCA represents consumers before the Pennsylvania Public Utility Commission (“the Commission”).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from Florida State University. I earned the designation of Chartered Financial Analyst (“CFA”) in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission (“NCUC”). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm.

I have been accepted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the New Jersey Commission of Public Utilities, the Colorado Public Utilities Commission, the District of Columbia Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in **Appendix A** to my answering testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the proper rate of return to allow

Columbia Gas of Pennsylvania, Inc. ("CPA" or "the Company") in the current proceeding.

Q. WHAT RATE OF RETURN IS CPA REQUESTING AS PART OF THIS PROCEEDING?

A. According to the testimony of CPA's Witness Paul D. Moul, CPA is seeking an overall rate of return of 7.88% based on the projected December 31, 2022 capital structure and cost rates as set forth in **Table 1** below.

Table 1: CPA's Requested Cost of Capital[1]

Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	41.77%	4.54%	1.90%
Short-Term Debt	3.89%	0.85%	0.03%
Common Equity	54.34%	10.95%	5.95%
Total Capitalization	**100.00%**		**7.88%**

Q. SHOULD THE COMMISSION ADOPT THE COMPANY'S COST OF CAPITAL CLAIM TO SET JUST AND REASONABLE RATES?

A. No. The Company's requested capital structure of 54.34% is too heavily weighted with equity when compared to various benchmark common equity ratios as detailed within **Section V**: Capital Structure. Further, the Company's 10.95% equity cost rate is overstated when compared to my Cost of Common Equity Analyses in **Section VII**: Cost of Common equity. The Company determined that their 10.95% equity ratio request of 10.95% request was appropriate based on flawed cost of

[1] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.

equity analyses that do not reflect market conditions as outlined within **Section VIII**: Review of Cost of Equity Analysis of Witness Moul. As outlined within the remainder of this testimony, adoption of the Company's requested cost of capital claim would overburden ratepayers, especially in light of the current economic conditions brought on by the COVID-19 pandemic, and given the fact that the Company was just allowed a rate increase as part of its 2020 rate case that concluded in February 2021.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- The proper capital structure to use in this proceeding is 50.00% common equity and 50.00% long-term debt;
- I agree that the proper embedded cost of debt to use in this proceeding is CPA's recommended future cost of short-term debt of 0.85% and long-term debt of 4.54%;
- The proper return on equity on which to set rates for CPA in this proceeding is 9.00%. This 9.00% recommendation is a market-based cost of equity which will allow the Company to access capital markets, while also ensuring that the rate is fair to the Company's captive customers; and

- The return on equity recommended by Witness Moul for CPA of 10.95% is excessive, unreasonable, and not indicative of current market conditions.

My recommended capital structure, ROE, and overall return are shown below within **Table 2** as based upon the results and data shown within **Exhibit KWO-1**:

Table 2: OCA Recommended Overall Rate of Return

Component	Ratio (%)	Cost Rate (%)	Weighted Cost
Long-Term Debt	42.12%	4.54%	1.91%
Short-Term Debt	7.88%	0.85%	0.07%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.48%**

II. CURRENT STATE OF THE FINANCIAL MARKETS AND CHANGES SINCE LAST CPA RATE CASE

Q. PLEASE DESCRIBE THE CURRENT STATE OF THE FINANCIAL MARKETS.

A. The equity market has rebounded strongly since the outbreak of the COVID-19 pandemic. Prior to the pandemic, the S&P 500 index, which represents the 500 largest companies in the United States, was close to 3400 (February 2020).[2] When the severity of the pandemic sank into the market, the S&P 500 index moved to just above 2300, representing roughly a 1/3 loss in the index.[3] As of June 11, 2021, the S&P 500 index closed over 4,200,[4] representing roughly a 75% gain from the low value that occurred on March 20, 2020. Clearly, investors have weathered the storm and are expecting solid growth from the US and world economy in the near future.

The debt markets have also rebounded from the impact of COVID-19. The Federal Reserve stepped in to ensure adequate liquidity to the markets and, as a result, interest rates stabilized and utilities were able to adequately obtain debt capital during the pandemic.

[2] https://www.google.com/search?q=s%26p+500+index&rlz=1C1CHBF_enUS912US912&oq=S%26P+500+index&aqs=chrome.0.0i67i131i433j0j0i20i263l2j0l6.8661j1j7&sourceid=chrome&ie=UTF-8
[3] *Id.*
[4] *Id.*

Q. DESCRIBE THE KEY ELEMENTS OF CPA'S RECENT RATE CASES.

A. The Pennsylvania Public Utility Commission ("PUC") approved a settlement of CPA's 2018 base rate case, which allowed CPA to increase rates.[5]

The Company's most recent base rate case was filed on April 24, 2020, based upon a fully projected future test year ending December 31, 2021 (Docket No. R-2020-3018835).[6] The Company requested a cost of equity of 10.95%, inclusive of an upward 20-basis point adjustment for management performance. The financial and market information in the record was from December 31, 2019, or earlier.

The Public Utility Commission allowed CPA an increase in rates, effective January 23, 2021, based upon a 9.86% cost of equity and an overall rate of return of 7.41%. The cost of debt was 4.73% for long-term debt and 2.06% for short-term debt. The capital structure was comprised of 54.19% equity, 42.22% long-term debt, and 3.59% short-term debt. The Commission denied CPA's management adder request.

Q. HAS THE DEBT MARKET FOR CPA CHANGED SINCE THE COMPANY'S 2020 BASE RATE CASE?

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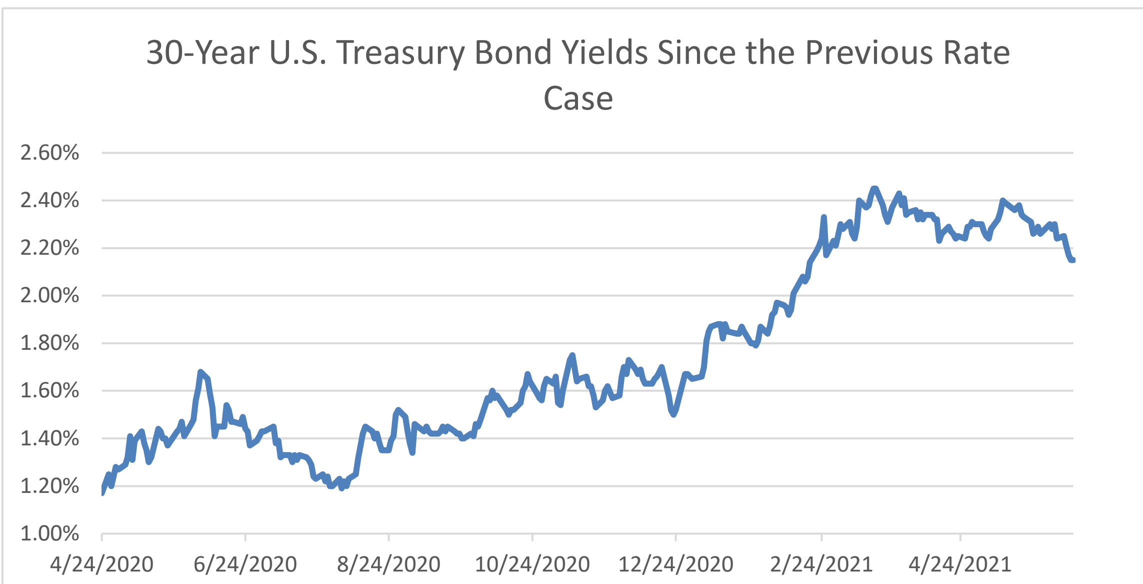
[5] Pa. Public Utility Commission v. Columbia Gas of Pennsylvania, Docket No. R-2018-2647577, Opinion and Order (entered December 6, 2018).
[6] Pa. Public Utility Commission v. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835, Opinion and Order (entered February 19, 2021).

A. Yes. The debt markets have changed since CPA filed its 2020 base rate case in April 2020 as exhibited in **Chart 1** below. Within this chart, I have provided the change in the 30-year US Treasury Bond yields from April 24, 2020 to June 11, 2021. The maximum value over this period was 2.45%, the average value was 1.74%, and the minimum value was 1.17%. Refer to **Chart 1** below for further details on the yield on 30-year US Treasury Bonds subsequent to the previous rate case.

Chart 1: Yield on 30-Year US Treasury Bonds[7]



Q. DOES CHART 1 ABOVE INDICATE THAT THE COMPANY'S COST OF DEBT IS HIGHER NOW THAN IT HAS BEEN HISTORICALLY?

[7] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield: **Date Accessed**: June 14, 2021.

A. No, not necessarily. CPA's 2018 base rate case concluded on December 6, 2018, the yield on the 30-year US Treasury bonds was 3.14%.[8] The current 30-year US Treasury Bond Yield on June 11, 2021 of 2.15%[9] is still significantly lower than what has been seen for the Company, and the market as a whole, in recent years. This would indicate that the parent company NiSource's cost of capital, in relation to its ability to access debt markets, has still been lower on average than what has been seen in recent years.

Q. HOW ARE INTEREST RATES EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. The Federal Funds Rate is the interest rate that banks charge to one another to borrow or lend excess reserves on hand overnight. This rate plays an important role in the movement of interest rates and the Federal Reserve's actions over the previous 18-months helps to showcase the steady decline in interest rates from 2018 to 2020. On March 15, 2020, in response to the COVID-19 outbreak and the disruptions to economic activity in this country across the globe, the Federal Reserve reduced the Federal Funds rate to 0.25%.[10]

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[8] *Id.*
[9] *Id.*
[10] *See* Commission of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Mar. 15, 2020), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm

The Federal Reserve has since stated that they do not expect to change the Federal Funds Rate at any time in the foreseeable future. Chairman Powell reinforced this view when he said in January 2021 that, "When the time comes to raise interest rates, we'll certainly do that, and that time, by the way, is no time soon."[11] Subsequent to the statements made by Chairman Powell in March 2021, the Federal Reserve explained that although they had sped up their overall expectation for economic growth, they continued to reinforce that they did not see any interest rate hikes likely through 2023.[12]

As noted above, while changes within the market have raised certain interest rate benchmarks during 2021, these interest rates still remain low in relation to historical interest rates. This lower interest rate environment has continued to provide a benefit to utilities from a borrowing perspective.

Q. HOW HAS THE STOCK MARKET FOR UTILITIES CHANGED OVER THE PAST YEAR AND A HALF?

A. Utilities have always been considered a safe harbor for investors during market turbulence or uncertainty, the COVID-19 pandemic is no different. During times of economic uncertainty, individuals and businesses still require the essential services provided by utilities. As such, the market for utilities remained strong during the

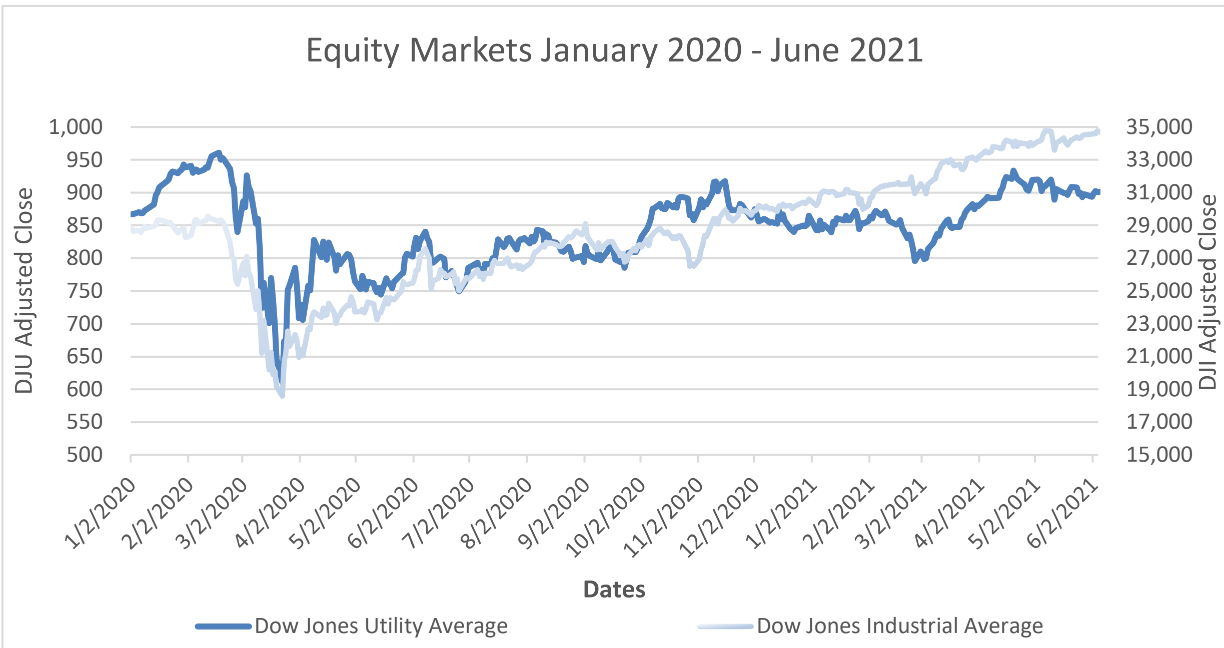
[11] https://www.cnbc.com/2021/01/14/powell-sees-no-interest-rate-hikes-on-the-horizon-as-long-as-inflation-stays-low.html

[12] https://www.cnbc.com/2021/03/17/fed-decision-march-2021-fed-sees-stronger-economy-higher-inflation-but-no-rate-hikes.html

past year and a half, even during the COVID-19 pandemic and associated economic shut-down.

Refer below to **Chart 2**, which is a double y-axis graph, which shows the change in the Dow Jones Utility Average ("DJUA") since the start of 2020 (*i.e.*, 1/2/2020 – 6/11/2021), as compared to the Dow Jones Industrial Average ("DJIA") over the same period.

Chart 2: DJIA to DJUA Comparison [13]



Although the DJIA is now at a level greater than that of the DJUA, the fluctuation in the DJIA over the period exhibited above was much more dramatic than that of the DJUA. This further enforces the fact that the utility market has remained

[13] https://finance.yahoo.com/quote/%5EDJU/components/ and https://finance.yahoo.com/quote/%5EDJI/history: **Date Accessed**: June 14, 2021.

stable and consistent, and provides support for the position that although markets were obviously impacted by the COVID-19 pandemic, utilities such as CPA have not had an issue accessing the capital markets. In light of this, CPA simply does not require a 10.95% ROE to attract and compete for capital in the current economic environment, especially given the positive market movements in 2021 as the overall economic recovery continues.

Q. DO YOU HAVE ANY OTHER SUPPORT FOR HOW UTILITIES LIKE CPA WERE STILL ABLE TO ACCESS THE CAPITAL MARKETS FOR UTILITIES EVEN DURING THE COVID-19 PANDEMIC?

A. Yes. On April 2, 2020, *S&P Global Intelligence* published an article entitled "*US utilities demonstrate access to capital with billions in debt offerings*". This article described how utilities tapped into current credit markets to obtain low-cost debt during periods of financial turbulence as noted in the excerpt below:

> Several utilities, including Xcel Energy and NextEra Energy Inc. subsidiary Florida Power & Light Co., which issued $1.1 billion in first mortgage bonds, are "*using the opportunity to take advantage of attractive borrowing costs, so there does not appear to be an inability to access capital*," they said.
>
> "*Utilities are reporting that recent deals have been significantly (7x) oversubscribed, highlighting that the capital markets are open for investment grade-rated utilities*," the analysts wrote. "*At the same time, we have also observed some utility companies that have fully drawn their bank lines as a precaution to provide them with liquidity*

> *in the event that markets seize up*," such as Duke Energy Corp. and American Electric Power Co. Inc.[14]

Additionally, during the midst of the early stages of the COVID-19 pandemic on April 29, 2020, *S&P Global Market Intelligence* published an article entitled "*Utility sector 'far and away' least impacted by EPS estimate cuts*."[15] Note that the date that this article was published was when markets were at their most volatile early on during the COVID-19 pandemic. The article provided the following observation:

> The S&P 500 utility sector has "far and away" experienced the least impact from earnings revisions since Feb. 28, the corporate bond research firm found. Despite market turmoil and the ongoing economic downturn, analysts have only cut earnings per share expectations for stocks in the utility sector by an average 1% for 2020 and 2021, according to CreditSights.
>
> By comparison, consumer staples, the next least-impacted sector, saw an average 5% decrease to EPS estimates for both years. Technology followed with a 9% estimate cut for 2020 and 2021.
>
> CreditSights pulled the data to measure the consensus view that utilities provide a safe harbor to investors. "*Water is wet, the sun will rise in the east and U.S. utilities are a defensive sector, but how defensive? Very defensive*," CreditSights analysts Andrew DeVries and Nick Moglia wrote in an April 29 research note.[16]

The above referenced article noted the ability of utilities to continue to operate based upon the conditions of the debt and equity markets. This allowed many utilities to perform strongly even in the face of the COVID-19 pandemic as

[14] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-utilities-demonstrate-access-to-capital-with-billions-in-debt-offerings-57881534
[15] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utility-sector-far-and-away-least-impacted-by-eps-estimate-cuts-58358458.
[16] *Id.*

referenced in the December 9, 2020 article from *S&P Global Intelligence*, entitled "*Resilient Utilities Post Notable EPS Gains*, *Solid ROEs Despite COVID-19 Pandemic*". The *S&P Global Intelligence* article noted:

> Despite the significant challenges caused by an economy that continued to be negatively impacted by COVID-19, utilities overall posted solid earnings growth and earned returns on equity during the third quarter, illustrating the tenet that utility finances hold up comparatively well in challenging economic environments.[17]

Although the utility sector was impacted by the COVID-19 pandemic just like the rest of the economy, utilities were much more resilient during this period than companies across other industries. The resilient performance of utilities, as well as their ability to continue to tap into debt markets, supported that the fact that utilities were still able to access a variety of capital markets throughout 2020, which continued into the 2021 after the capital market resurgence.

Q. WHAT HAVE BEEN THE IMPACTS ON THE EQUITY MARKETS AS A RESULT OF THE COVID-19 PANDEMIC?

A. As shown in **Chart 2**, equity markets were negatively impacted during the first two quarters of 2020, before later rebounding during the second half of 2020 and into 2021. During the majority of 2020, businesses were closed, and workers stayed home as the United States and world economies slowed dramatically prior to the beginning of phased reopening plans around the world. While I note that the

[17] https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#news/articleabstract?id=61646964

economic recovery that began during the latter part of 2020 has continued into 2021, and that there is an expectation that the economy will continue its rebound throughout 2021, there is no current expectation that the economy will fully recover, or that the sustained civilian unemployment rate will reach pre-2020 levels, at any point in the near-term.

To that point, Federal Reserve Chairman Jerome Powell noted that although there was growth in the second half of 2020, the timeline for a full economic recovery across a variety of indicators remains uncertain as referenced within the following quote from December 1, 2020:

> Economic activity has continued to recover from its depressed second quarter level. The reopening of the economy led to a rapid rebound in activity, and real gross domestic product, or GDP, rose at an annual rate of 33 percent in the third quarter. In recent months, however, the pace of the improvement has moderated…The economic downturn has not fallen equally on all Americans, and those least able to shoulder the burden have been the hardest hit...The economic dislocation has upended many lives and created great uncertainty about the future…As we have emphasized throughout this pandemic, the outlook for the economy is extraordinarily uncertain…[18]

During a press conference on March 17, 2021, Chairman Powell then noted that:

> The overall recovery in economic activity since last spring is due importantly to unprecedented fiscal and monetary policy actions, which have provided essential support to households, businesses, and communities. The recovery has progressed more quickly than generally expected, and forecasts from FOMC participants for economic growth this year have been revised up notably since our December Summary of Economic Projections…As with overall economic activity, conditions in the labor market have turned up recently. Employment rose by 379,000 in February, as the leisure

[18] https://www.federalreserve.gov/newsevents/testimony/powell20201201a.htm

> and hospitality sector recoupled about two-thirds of the jobs that were lost in December and January. Nonetheless, employment in this sector is more than 3 million below its level at the onset of the pandemic. For the economy as a whole, employment is 9.5 million below its pre-pandemic level. The unemployment rate remains elevated at 6.2 percent in February; this figure understates the shortfall in employment, particularly as participation in the labor market remains notably below pre-pandemic levels.[19]

Chairman Powell also noted on April 12, 2021 that, "The recovery, though here, remains uneven and incomplete. <u>The burden is still falling on lower-income workers and the unemployment rate in the bottom quartile is still 20 percent</u>."[20] Additionally, Michelle Bowman (Federal Reserve Board Governor) stated on May 5, 2021 that:

> The economic recovery is not yet complete, and the uncertain course of the pandemic still presents risks in the near term…Despite the progress to date and the signs of acceleration in the recovery, employment is still considerably short of where it was when the pandemic disrupted the economy and it is well below where it should be, considering the pre-pandemic trend.[21]

To this same point, Lael Brainard (Federal Reserve Board Governor) also noted on May 11, 2021 that, "The latest jobs report reminds us that while there are good reasons to expect the number of jobs and the number of people wanting to work will make a full recovery, it is unlikely they will recover at the same pace…Job losses are disproportionately concentrated in low-wage, high-contact sectors,

[19] https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20210317.pdf
[20] https://www.aljazeera.com/amp/economy/2021/4/8/powell-economy-will-not-be-confident-until-world-is-vaccinated (underlined emphasis added)
[21] https://www.federalreserve.gov/newsevents/speech/bowman20210505a.htm

suggesting that workers least able to shoulder the economic effect of job loss have faced the greatest challenges."[22]

As referenced in the quotes above, although there has been considerable growth and recovery within the capital markets over the second half of 2020, and into 2021, the individuals within CPA's customer base that were most negatively impacted by the pandemic are still struggling with such issues. Even while economic growth within the markets has grown at a rate faster than anticipated as COVID-19 cases declined and economies began to reopen, there are key indicators (such as employment figures) that remain depressed. As such, any additional rate increases subsequent to what was just allowed to CPA in the rate case that concluded in February 2021 would only continue to exacerbate the negative economic circumstances encountered by this portion of CPA's consumer base.

Q. WHAT OTHER FACTORS SHOULD THE COMMISSION CONSIDER IN DETERMINING AN APPROPRIATE COST OF CAPITAL FOR COLUMBIA GAS?

A. The ability of a utility to access the capital markets is just part of the determination of an appropriate cost of capital for ratesetting. The Commission should also consider the position of ratepayers who must continue to make non-discretionary

[22] https://www.federalreserve.gov/newsevents/speech/brainard20210511a.htm#fn13

purchases, such as gas, electricity, or water from monopoly utilities, regardless of the impact of the COVID-19 pandemic.

Many consumers at the residential, commercial, and industrial levels have struggled to pay their utility bills as unemployment levels spiked during 2020 and remained higher than average into the second half of 2020 and into 2021, with various businesses also shut down for extended time over this period.

For instance, while the financial markets began a rebound in the third quarter of 2020, the average civilian unemployment rate still exceeded what was common in prior periods. The unemployment rate was heightened at 6.77% in Q4 2020 and averaged 8.12% during the entirety of 2020.[23] For comparison purposes, the average monthly civilian unemployment rate from 2019 was 3.67%.[24] While the unemployment rate improved through the second half of 2020 and into 2021, it still averaged 6.17% for Q1 2021 and 6.1% and 5.8% during April and May 2021, respectively.[25]

When comparing the unemployment rates between these time periods, this further reinforces that the Company's "business as usual" request is not appropriate in the current economic climate for its customers, especially when one considers

[23] https://www.bls.gov/charts/employment-situation/civilian-unemployment-rate.htm
[24] *Id.*
[25] *Id.*

that CPA's most recent rate case and request for increased rates upon its customer base just concluded in February 2021.[26]

Q. WHY DO YOU BELIEVE THE COMPANY'S 10.95% ROE REQUEST IN THIS CASE IS NOT APPROPRIATE GIVEN THE CURRENT STATE OF THE FINANCIAL MARKETS?

A. In CPA's most recently concluded base rate case, Mr. Moul recommended a 10.75% market-based ROE, plus 20-basis points for management performance, for a total ROE of 10.95%.[27] In this current proceeding, Mr. Moul has recommended a 10.95% ROE as market-based.

Based upon my cost of equity analyses discussed below, a market-based cost of equity for CPA at the end of the FPFTY should be no higher than 9.00%. The Commission's determination of an appropriate cost of equity must balance the needs of the consumers, not just the interests of CPA. Many of CPA's customers are still dealing with ongoing financial struggles linked to a variety of factors, such as higher than average unemployment numbers throughout 2020 and 2021. My recommended cost of capital for CPA is based upon a careful analysis of current financial data, disciplined application of cost of equity models to an appropriate proxy group of natural gas utilities, and identification of an appropriate capital

[26] Pennsylvania Public Utility Commission Docket No. R-2020-3018835 Opinion and Order Adopting Initial Decision/Stipulation (2/19/2021).
[27] PA Docket No. R-2020-3018835: Witness Moul's Direct Testimony, page 2: line 2.

structure for setting rates. My cost of capital recommendation for CPA balances the Company's need to access the markets and the interests of consumers who will be asked to pay the rates for essential natural gas distribution utility service.

Q. DOES CPA'S 10.95% ROE REQUEST INCLUDE ANY UPWARD ADJUSTMENT TO REWARD THE COMPANY FOR ANY CLAIMED EFFECTIVE PERFORMANCE OF MANAGEMENT?

A. No, Company witness Mark Kempic stated that the Company is not seeking a rate of return adjustment.[28] In reply to Question No. **OCA-VI-2**, the Company confirmed this. Nor has the Company identified an adjustment to any other element of the ratemaking formula to recognize management performance, per the reply to Question No. **OCA-VI-2**. In the Company's last base rate case, I opposed CPA's request for a management performance adder in principle and on the merits. Since CPA is not requesting such an adjustment in this case, there is no need to repeat that analysis and line of reasoning.

Q. ARE THERE ANY CURRENT MARKET CONDITIONS THAT WOULD GIVE RISE TO CONCERNS ABOUT THE MARKET'S OVERALL PRICING?

[28] Witness Kempic's Direct Testimony, page 22.

A. I recognize that on June 10, 2021, the Consumer Price Index ("CPI") reported results that were higher than anticipated by economists and the market. However, this report of inflation is too early to tell if the United States economy will suffer due to rising prices. In order to capture as much of this change as possible, I have examined markets as close to the testimony filing deadline as possible in this case.

III. ECONOMIC AND REGULATORY POLICY GUIDELINES FOR A JUST AND REASONABLE RATE OF RETURN

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE JUST AND REASONABLE RATE OF RETURN THAT UTILITY COMPANIES SHOULD HAVE AN OPPORTUNITY TO EARN.

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Within the gas industry, the transmission and distribution of gas to utilities' end-use customers is still a monopolistic business and will, for the foreseeable future, be regulated. On this basis, state legislatures and state utility commissions/boards established exclusive franchised territories to public utilities in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide service that is adequate and non-discriminatory at just and reasonable rates.

This trade-off logically leads to the question – what constitutes a just and reasonable rate? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a just and reasonable rate of return on invested capital. The just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators.

If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise capital on reasonable terms. As such, regulators are tasked with balancing the related interests of the interested parties (*i.e.*, the utility's equity investors, the utility itself, and the utility's customers at the varying residential, commercial, and industrial levels). This balancing act results in what regulators, analysts, and courts often refer to as setting rates within a "zone of reasonableness." Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the just and reasonable rate of return for a utility.

As I previously referenced above, CPA filed its previous rate case in April 2020, and its current rate case in March 2021. In the time that has lapsed between these two cases, the country experienced an economic recession spurred on by a pandemic the likes of which have not been seen in this country for over a century. Accordingly, what a utility may have initially deemed as constituting just and reasonable rates during prior years may simply be construed as unreasonable today given the current economic climate absent any of the other particulars of their request.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE SUPREME COURT'S *HOPE* AND *BLUEFIELD* DECISIONS.

A. Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair, just, and reasonable rate of return in two often-cited cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679; and the *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

In the *Bluefield* case, the U.S. Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon 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; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. 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. (262 U.S. at 692)

In the above finding, the Court found that utilities are entitled to earn a return on investments of comparable risks and that a corresponding return should be sufficient enough to support credit activities and to raise funds to carry out its mission.

In *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn. In *Hope Natural Gas*, the U.S. Supreme Court stated that the return to equity owners (or shareholders) of a regulated public utility should be commensurate to returns on investments in other enterprises whose risks correspond to those of the utility being examined:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital. (320 U.S. at 603)

IV. DEVELOPMENT OF PROXY GROUP

Q. PLEASE DESCRIBE HOW YOU SELECTED A PROXY GROUP FOR ESTIMATING CPA'S RETURN ON EQUITY.

A. The number of available gas utilities needed to develop a reasonably reliable comparable group is dwindling. Over the past several years, certain gas utilities have been acquired by large electric utility holding companies. These acquisitions make sense for electric utilities as they desire to grow their source of regulated earnings while, at the same time, gain natural gas infrastructure that allows them to control the distribution of natural gas.

In regard to the composition of my proxy group, I opted to use the full group of gas utilities compiled and followed by *Value Line*. As such, each of the companies included by Mr. Moul within his proxy group are also included within my own proxy group. However, in contrast to Mr. Moul, I did not remove UGI Corporation from my proxy group. My reasoning for this is detailed in a below Q&A.

Additionally, unlike Mr. Moul, I have chosen to perform an analysis directly on NiSource. CPA is a wholly owned subsidiary of NiSource Gas Distribution Group, which is itself a wholly owned subsidiary of NiSource, Inc. As such, I found it appropriate to perform a specific, singular analysis of NiSource, Inc. as it provides the most directly observable link between any company within the comparable proxy group and CPA.

Mr. Moul also opted to include a non-utility comparable proxy group for comparison purposes to CPA within his Comparable Earnings Analysis as he noted that:

> 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.[29]

In contrast, I have not chosen to include a non-utility group within any of the analyses included within my testimony as, in my view, such non-regulated companies are not truly comparable to CPA and should not be examined in regard to determining the proper ROE to grant a regulated utility such as CPA. While utilities are in a sense "competing" against non-utilities strictly for the capital of investors looking to build their portfolio, only regulated utilities have the ability to seek regulatory relief.

CPA is a regulated utility. The Company has a set of consumers at the residential, commercial, and industrial levels that are locked into purchasing natural gas distribution service from CPA. If CPA feels that they need to increase their ROE in order to result in a greater overall Rate of Return, they have the ability to request regulatory relief through a rate case in an effort to increase rates on captive customers. Unregulated entities and non-utilities do not have the ability to ask for rate relief like regulated utilities do. Seeking rate relief is an integral part of the

[29] Witness Moul's Direct Testimony, page 41: lines 5 – 7.

business model of a regulated utility and is not a practice that is available to any such non-utilities.

Q. WHY DID YOU CHOOSE TO INCLUDE UGI CORP WITHIN YOUR COMPARABLE GROUP, WHILE MR. MOUL OMITTED THE COMPANY FROM HIS ANALYSIS?

A. Within his direct testimony, Mr. Moul stated that in developing his proxy group, he first began with the companies included in *Value Line's* Natural Gas Utility industry.[30] However, he made an adjustment in that he excluded those companies that were not predominantly engaged in natural gas distribution (*i.e.*, UGI Corp). Specifically, he noted that "UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and gas generation."[31]

For context, UGI Corp. has a diversified business portfolio that, along with the natural gas utility, contains propane, international liquid propane gas ("LPG"), energy service, and electric generation. By comparison, Chesapeake Utilities, which Mr. Moul opted to include within his proxy group, also operates a diverse set of businesses that includes natural gas distribution, natural gas transmission, electric distribution operations, propane distribution, propane wholesale marketing

[30] Witness Moul's Direct Testimony, page 4: lines 15 – 16.
[31] Witness Moul's Direct Testimony, page 4: lines 18 – 21.

and natural gas marketing operations, and real estate operations. As such, for consistency purposes, and in consideration of the fact that both companies are included by *Value Line* within their Natural Gas Utility Industry, I did not feel it appropriate to include one diverse company within my proxy group, while simultaneously excluding another.

Q. PLEASE EXPLAIN WHY YOU PERFORMED A COST OF EQUITY ANALYSIS SEPARATELY ON NISOURCE.

A. CPA is owned by NiSource. As the owner of CPA, NiSource therefore represents the most direct link to CPA, and an analysis performed specifically on NiSource helps to provide a large body of knowledge of investor expectations.

V. <u>CAPITAL STRUCTURE</u>

Q. DO YOU ACCEPT THE COMPANY'S PROJECTED CAPITAL STRUCTURE FOR RATEMAKING?

A. No, I do not. As addressed below, the Company does not issue its own debt or equity in the public financial markets. The Company's financing is provided through NiSource, Inc., which owns the Company's equity stock.

I recommend that the Commission set rates based upon a capital structure comprised of 50% debt and 50% equity, to more properly balance CPA's need for capital and the interests of ratepayers, as explained below.

Q. WHAT IS A CAPITAL STRUCTURE AND HOW DOES IT IMPACT THE REVENUES THAT CPA IS SEEKING?

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. A company's capital structure typically includes some combination of three principal financing methods.

The <u>first</u> method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Common equity is comprised of all investments from investors, including common stock, retained earnings, and additional paid in capital. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 21% more expensive than debt financing.

The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible.

Debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Long-term debt and short-term debt, both of which are "above the line" expenses for tax purposes, represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure, represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books, by the cost rates associated with each form of capital and then totaling the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax rate of return is developed. Because the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to pre-tax returns by grossing up the common equity and preferred stock dividends for taxes. The final pre-tax return is then multiplied by the Company's rate base in order to develop the amount of money that customers must pay to the utility for return on investment and tax payments associated with that investment.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. Costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock versus long-term debt. However, long-term debt, which is first in line for repayment, imposes a contractual obligation to make fixed payments on a pre-established schedule, as opposed to common equity where no similar obligations exist.

Q. WHY SHOULD THE COMMISSION BE CONCERNED ABOUT HOW THE COMPANY FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how CPA finances its rate base investment. First, CPA's cost of common equity is higher than the cost of long-term debt, meaning that a relatively higher equity percentage will translate into higher costs to CPA's customers without any corresponding improvement in quality of service. Long-term debt is a financial promise made by a company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the contingent nature of an equity investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a more senior claim against the company's assets.

The second reason the Commission should be concerned about CPA's capital structure is due to the tax treatment of debt versus common equity. Corporations can deduct payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. The regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, within their rates. Accordingly, if a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to cover the higher income tax burden, which can result in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of a capital structure that is weighted too heavily in common equity violates the fundamental principles of utility regulation that rates must be just and reasonable and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. DOES A UTILITY SUBSIDIARY LIKE COLUMBIA GAS SET ITS OWN CAPITAL STRUCTURE?

A. No. Columbia Gas' stock is owned by NiSource, Inc., which the parent holding company for several utilities.[32] Specifically, NiSource owns Columbia Gas of Pennsylvania, Columbia Gas of Maryland, Columbia Gas of Virginia, Columbia Gas of Ohio, Columbia Gas of Kentucky, NIPSCO Gas, and NIPSCO Electric.[33] As the owners of these utilities, NiSource is able to set the capital structure of these utilities as it sees fit. For example, NiSource, which has a common equity ratio of 32.9%[34], could issue debt and then infuse this debt into Columbia Gas of Pennsylvania and call it common equity. In such a circumstance, NiSource could use the regulatory system to increase debt issuances at a rate of approximately 3.5% to produce a pre-tax rate of return for stockholders of over 10%. The alternative to NiSource is to issue debt and then support that debt issuance with debt from CPA. In either event, the capital structure of Columbia Gas of Pennsylvania is, for the most part, at the discretion of its owner, NiSource.

Q. HOW DOES A UTILITY'S SELECTION OF EQUITY VERSUS DEBT IMPACT RATEPAYERS?

A. Entities in more competitive markets have a profit motive that provides an incentive for such entities to select the most efficient capitalization ratio. However, utilities operating in monopoly, rate-regulated service territories have an incentive

[32] Witness Moul's Direct Testimony, page 3: lines 6-10; page 13: lines 7-8.
[33] https://investors.nisource.com/company-information/default.aspx
[34] *The Value Line Investment Survey*, May 28, 2021.

to maximize the amount of common equity in their capital structure, to increase revenues and, correspondingly, the utility profit. Rate-regulated utilities should only be allowed to recover in rates a revenue requirement derived from a capitalization ratio that allows the utility to provide reliable service at the least cost. Therefore, finding the right balance between debt and equity is critical.

If a utility issues more common equity and less debt for a certain project, the rates could potentially be set at an unbalanced debt to equity level. This could result in the ratepayer paying higher rates to support a capital structure that is neither prudent nor reasonable to support the company's current credit rating or the company's adequate access to the capital markets. It is also important to recognize how rate levels affect economic development. The reality in today's economy is that economic development opportunities for large loads occur in places where costs are lower. A utility with unduly high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

If, on the other hand, the utility incurs too much debt, the utility's capitalization ratios present excess financial risk to the capital markets, thereby driving up the costs required by the equity markets to compensate for the added risk. In this case, the consumer would also be negatively impacted because the cost it must pay the utility for accessing the capital markets would be higher than it would be using a less debt-leveraged capital structure.

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Either too much equity or too much debt can harm both the stockholders of the corporation, as well as the consuming public.

Q. HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING IN THIS CASE?

A. CPA has proposed the following capital structure:

Table 3: CPA Requested Capital Structure[35]

Component	Capital Structure Ratio (%)
Long-Term Debt	41.77%
Short-Term Debt	3.89%
Common Equity	54.34%
Total Capitalization	**100.00%**

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN YOUR PROXY GROUP?

[35] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400.**

A. **Table 4** below shows the average common equity ratio of each utility in my gas comparable company proxy group, as well as for NiSource (*i.e.*, CPA's parent company).

Table 4: Proxy Group Equity Ratio[36]

Company	2019 Ratio	2020 Ratio	2021E* Ratio	2024E* – 2026E* Ratio
Atmos Energy	62.00%	60.00%	52.00%	60.00%
Chesapeake Utilities	56.10%	57.80%	57.00%	60.00%
New Jersey Resources	50.20%	44.90%	46.00%	47.00%
Northwest Natural	51.80%	50.80%	51.00%	57.00%
ONE Gas Inc	62.30%	58.50%	36.00%	53.00%
South Jersey Inds	40.80%	37.40%	37.00%	39.50%
Southwest Gas	52.10%	49.50%	49.50%	52.00%
Spire Inc	55.00%	51.00%	51.00%	55.00%
UGI Corp	39.80%	40.80%	43.50%	50.00%
Average	**52.23%**	**50.08%**	**47.00%**	**52.61%**
NiSource Inc	36.90%	32.90%	40.00%	40.00%

As can be seen in the table above, the average common equity ratio for the proxy group in 2019 was 52.23%, the average common equity ratio for 2020 was 50.08%, the average expected common equity ratio for 2021 is 47.00%, and the average expected common equity ratio from 2024 – 2026 is 52.61%. Additionally, the respective ratios for NiSource for the same periods noted above are 36.90%, 32.90%, 40.00% and 40.00%, respectively.

[36] *The Value Line Investment Survey*, May 28, 2021 (Natural Gas Utilities).

Each of these metrics is below the Company's requested equity ratio in this case of 54.34%, and the 2024E – 2026E expected ratio of 52.61% that is closest to the Company's 54.34% request is the furthest out estimate and the most inherently volatile and uncertain estimation.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTILITY REGULATORS FOR GAS UTILITIES ACROSS THE UNITED STATES?

A. Note that I have sourced the average common equity ratio values granted by utility regulators for gas utilities from across the country from *S&P Global*. In my research into these numbers, I found that four states included within the overall average value of gas utilities across the country report their allowed common equity ratios on an all capital sources basis (*i.e.*, LT Debt, ST Debt, Common Equity, Preferred Stock, Customer Deposits, Deferred Income Taxes, Investment Tax Credits). As such, I have removed these four states (*i.e.*, Arkansas, Florida, Indiana and Michigan) from these numbers to ensure that each of the states included in this average report their allowed common equity ratio percentages only on investor sources of capital (*i.e.*, LT Debt, ST Debt, Common Equity). I wanted to remove these four states from the overall average to ensure that this represented an appropriate comparison given that CPA's requested equity ratio in this case of 54.34% is based solely off of investor sources of capital.

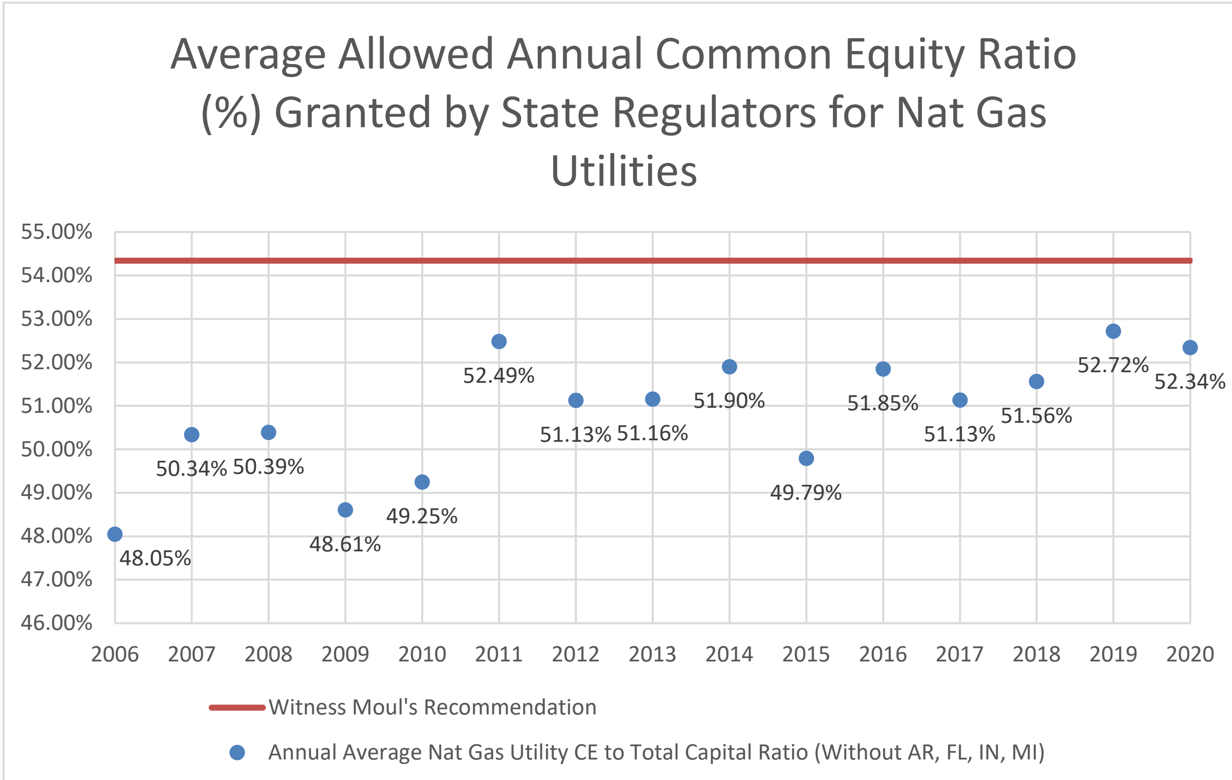
The resulting average common equity ratio granted by regulators for natural gas utilities for all states on an investor sources basis 2020 was 52.34%.[37]

Q. WHAT COMMON EQUITY RATIOS HAVE STATE REGULATORS ACROSS THE UNITED STATES GRANTED TO NATURAL GAS UTILITIES OVER THE PAST 15 YEARS?

A. State regulators have been quite consistent in their rulings in natural gas cases for allowed common equity ratios based on investor sources of capital over the past 15 years. From 2006 through 2020, common equity ratios have ranged from 48.05% to 52.71%, with an average of 50.85%. If one were to evaluate this data over the previous 12 years, the average common equity ratio over this period is 51.16%, the average ratio over the previous 10 years is 51.61%, and the average ratio over the previous 8 years is 51.56%. In **Chart 4** below I have presented the average annual common equity ratio granted by state regulators for each year over the past 15 years.

[37] S&P Global Market Intelligence Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Common Equity to Total Capital, Return on Equity; **Date Accessed**: June 1, 2021.

Chart 4: Common Equity Ratio Granted by State Regulators (2006 – 2020)[38]



Q. WHAT IS THE CAPITAL STRUCTURE OF NISOURCE, THE PARENT HOLDING COMPANY OF CPA?

A. As shown in **Table 4** above, the NiSource equity ratio as of December 31, 2020 was 32.90%, and it is expected by analysts to be at 40.0% through the 2024-2026E time period.

Q. IS THE CAPITAL STRUCTURE OF CPA RELATED TO THE CAPITAL STRUCTURE OF NISOURCE?

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[38] *Id.*

A. Yes. According to Company witness Moul CPA "…obtains its external capital from NiSource Inc."[39] The Company contracts for the use of debt capital from NiSource.[40] In response to OCA discovery inquiring about the Company's efforts to refinance certain high cost debt obligations, CPA replied:

> The Company's intercompany promissory notes are generally pre-payable, without premium or penalty, at any time after the first anniversary of the issuance date. However, NiSource's external bonds that support the intercompany promissory notes require call premiums and bank fees for early redemption, which impacts the economics of refinancing.[41]

The Company obtains its short-term debt from the NiSource money pool, which has as its source commercial paper.[42] The Company's equity ratio accounts for expected "equity infusions" in the FTY and FPFTY.[43]

NiSource controls the amount of debt and equity in the CPA capital structure. The fact that CPA is asking for a 54.34% equity ratio, while NiSource has a 40% equity ratio, indicates that the holding company is using double-leverage to increase profits from its regulated subsidiary, CPA.

Q. PLEASE EXPLAIN THE CONCEPT OF DOUBLE LEVERAGE.

A. Double leverage occurs when a utility parent company issues debt and then infuses that debt into the regulated subsidiary as common equity. The reason for such action

[39] Witness Moul's Direct Testimony, page 12: line 5.
[40] Witness Moul's Direct Testimony, page 17: lines 22-23.
[41] Witness Moul's response to Question No. **OCA-VI-9**.
[42] Witness Moul's Direct Testimony, page 18: lines 12-13.
[43] Witness Moul's Direct Testimony, page 17: lines 4-6.

is that equity is more expensive than debt and it is grossed up for taxes, meaning that the costs that NiSource can collect from CPA is far greater than the cost of issuing the debt.

Q. PLEASE PROVIDE AN EXAMPLE OF DOUBLE-LEVERAGE.

A. An example would be a parent holding company issuing debt at 3.5% and then infusing the debt proceedings into the utility subsidiary as equity where the utility earns an allowed ROE of 9.0%. Keep in mind that the regulated utility is allowed to recover its income taxes so the 9.0% is actually grossed up to approximately 12.5% to pay for income taxes. As a result, through the regulatory process, NiSource can issue debt at 3.5% and turn it into 12.5% through double-leverage through its relationship with its subsidiaries.

Q. PLEASE SUMMARIZE YOUR FINDINGS IN REGARD TO THE REQUESTED EQUITY RATIO IN THIS CASE RELATIVE TO THE EQUITY RATIO OF OTHER GAS UTILITIES.

A. **Table 5** below provides a summary of how CPA's request in this case compares to the average equity ratio of the proxy group companies, the common equity ratio of CPA's parent company, NiSource, and the average equity ratio allowed by state regulators to gas utilities across the country in 2020 and the previous 15-year period.

Table 5: Common Equity Ratio Comparison

CPA's Eq Ratio Request	54.34%
OCA Eq Ratio Recommendation	50.00%
2019 O'Donnell Proxy Group Actual Eq Ratio Average	52.23%
2020 O'Donnell Proxy Group Actual Eq Ratio Average	50.08%
2021E O'Donnell Proxy Group Expected Eq Ratio Average	47.00%
2024E – 2026E O'Donnell Proxy Group Expected Eq Ratio Average	52.61%
2019 NiSource Actual Eq Ratio Average	36.90%
2020 NiSource Actual Eq Ratio Average	32.90%
2021E NiSource Expected Eq Ratio Average	40.00%
2024E – 2026E NiSource Expected Eq Ratio Average	40.00%
2020 Average Annual Regulator Granted Eq Ratio	52.34%
2006 – 2020 Average Annual Regulator Granted Eq Ratio	50.85%

Q. GIVEN THE ABOVE, DO YOU BELIEVE THAT THE CAPITAL STRUCTURE PROPOSED BY CPA IN THIS CASE IS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No. The requested capital structure for CPA is not reasonable for ratemaking purposes. Nothing in the make-up of CPA suggests that it requires an equity ratio in a range that would place it higher than that of the companies within its comparable proxy group. Indeed, some of the companies in the proxy group are involved in a wider array of business activities that involve more business risk than a utility's distribution of natural gas within its monopoly service territory. As such, if anything, the financial risk (as represented by the equity ratio) of the comparable company proxy group should be higher, not lower, than a traditional gas utility such as CPA. Customers of CPA should not pay higher rates associated with a capital structure that consists of so much common equity which, as previously discussed, is more expensive than debt.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND THIS COMMISSION ADOPT FOR USE IN SETTING THE REVENUE REQUIREMENT IN THIS CASE?

A. My recommendation is for the Commission to employ a capital structure that contains an equity ratio that is more equivalent to the common equity ratio granted by state regulators across the country over the previous 15-year period, the common equity ratios applicable to the proxy group included above, and the common equity ratios applicable to CPA's own parent company, NiSource. Specifically, my recommended capital structure and embedded cost of debt is as follows:

Table 6: OCA Recommended Capital Structure

Component	Capital Structure Ratio (%)
Long-Term Debt	42.12%
Short-Term Debt	7.88%
Common Equity	50.00%
Total Capitalization	100.00%

Note that the overall debt ratio of 50% was developed from the fact that the Company's overall embedded debt cost rate is 5.39%, its LT Debt cost rate is 4.54%, and its ST Debt cost rate is 0.85%. I have used those same, specific ratios to split out the overall 50% debt portion of the capital structure between short-term and long-term.

Q. HOW DID CPA DEVELOP ITS REQUESTED COMMON EQUITY RATIO OF 54.34%?

A. Mr. Moul adopted "the Company's FPFTY capital structure ratios of 41.77% long-term debt, 3.89% short-term debt, and 54.34% common equity at December 31, 2022."[44] Mr. Moul compared the Company's projected common equity ratio to the five-year average common equity ratio, based on permanent capital for CPA (55.1%), his Gas Group (52.6%), and for the S&P Public Utilities (42.2%). Mr. Moul concluded that "The Company's common equity ratio was fairly similar to the Gas Group, thereby indicating similar financial risk."[45]

Q. DO YOU AGREE THAT THE COMPANY'S PROJECTED EQUITY RATIO IS REASONABLE BASED UPON MR. MOUL'S COMPARISON TO HISTORIC RATIOS?

A. No, I do not. Mr. Moul's testimony then included **Schedule 3** on page 5 of **Exhibit No. 400** that showcased the historical common equity ratios for Mr. Moul's proxy Gas Group from 2015 – 2019. Within this schedule, Mr. Moul presented the common equity ratios for his proxy group over the five-year historical period from 2015 through 2019 on a permanent capital and total capital basis and then averaged these data points.

[44] Witness Moul's Direct Testimony, page 17: lines 12 – 15.
[45] Witness Moul's Direct Testimony, page 13: lines 18 – 21.

Permanent capital excludes short-term debt whereas total capital includes short-term debt. Given that gas utilities are a definite seasonal business, and that short-term debt is often replaced with long-term debt, I believe the more accurate comparison is by total capital, which includes short-term debt.

As one can see within Mr. Moul's **Schedule 3** of **Exhibit No. 400**, the common equity ratio for Mr. Moul's Gas Group from 2015 – 2019 on a total capital basis is 47.2%,[46] which is obviously well below my recommendation of a 50.00% common equity ratio. The common equity ratio for his Gas Group from 2015 – 2019 on a permanent capital basis saw a decline from 54.0% in 2015 to 50.3% in 2019, and from 47.2% in 2015 to 45.3% in 2019 on a total capital basis,[47] thus exhibiting a clear declining trend in the average equity ratio across Mr. Moul's Gas Group on both a total and permanent capital basis.

Based upon an examination of the historical and forecasted metrics provided by *Value Line* (*i.e.*, the average proxy group capital structure for 2019, 2020, and 2021E as shown above in **Table 4** and **Table 5**), these other metrics suggest a capital structure for CPA that is more in line with what I have recommended at 50.00%. The same is true if one is to consider the Average Annual Regulator Granted Equity Ratios across the country over the periods outlined within **Table 5**.

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[46] Witness Moul's Direct Testimony: **Schedule 3** of **Exhibit No. 400**.
[47] Witness Moul's Direct Testimony: **Schedule 3** of **Exhibit No. 400**.

In consideration of this additional data, I believe these values further support a debt to equity split for the Company's capital structure of 50% – 50%.

Q. IF THE COMMISSION ADOPTS THE COMPANY'S CAPITAL STRUCTURE FOR RATEMAKING, WHAT OTHER ADJUSTMENTS SHOULD IT MAKE?

A. Note that my specific equity recommendations in this proceeding based on the analyses performed is a capital structure weighted 50% to common equity, along with a 9.00% ROE, as shown in **Table 2**. However, if the Commission were to adopt a capital structure for CPA at the level requested by the Company, the PUC should recognize the lower financial risk applicable to CPA with such an equity ratio, and accordingly reduce the allowed ROE in this proceeding.

VI. COST OF DEBT

Q. DO YOU ACCEPT THE COMPANY'S COST OF DEBT?

A. Yes, I accept the Company's 4.23% total cost of debt, based on 4.56% long-term and 0.85% short-term debt cost rates.[48]

Please note that the Commission should recognize that the Company's projected average total cost of debt of 4.23% is based upon financing from NiSource. Specifically, NiSource issues debt at the parent company level and provides loans to CPA that then serve to support the NiSource debt. This "debt-to-debt" relationship is an example of how NiSource controls the relative amounts of debt in the CPA capital structure.

However, based on my evaluation of the cost of debt supporting documents provided by the Company during this rate case proceeding, I agree with the Company's proposed cost of debt of 4.23%.

[48] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.

VII. COST OF COMMON EQUITY

Q. PLEASE EXPLAIN HOW THE ISSUE OF DETERMINING AN APPROPRIATE RETURN ON A UTILITY'S COMMON EQUITY INVESTMENT FITS INTO A REGULATORY AUTHORITY'S DETERMINATION OF JUST AND REASONABLE RATES FOR THE UTILITY.

A. In Pennsylvania, as in virtually all regulatory jurisdictions, a utility's rates must be "just and reasonable."[49] Thus, regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a just and reasonable rate of return on the capital invested in a utility's facilities, such as natural gas distribution equipment, buildings, vehicles, and similar long-lived capital assets.

Q. HOW DO REGULATORY AUTHORITIES DETERMINE WHAT WOULD CONSTITUTE A JUST AND REASONABLE RATE OF RETURN ON EQUITY FOR A UTILITY COMPANY?

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity. Among the measures used are the Discounted Cash Flow ("DCF") Model, the Comparable

[49] Chapter 13 of the Pennsylvania Public Utility Code sets forth rate-making standards, including the requirement that utility rates be just and reasonable.

Earnings Analysis ("CEA"), and the Capital Asset Pricing Model ("CAPM"). I believe the most useful methodology is the DCF analysis, but I have also presented the CEA and the CAPM within this testimony as checks for my DCF results.

Note that this line of thinking is also specific to cases in Pennsylvania, as the Pennsylvania Utility Commission has historically used the CAPM as a check on the reasonableness of the results derived from the DCF analysis as well.[50]

Q. CAN YOU EXPLAIN WHY REGULATORY AUTHORITIES AND FINANCIAL ANALYSTS NEED TO USE THESE METHODOLOGIES TO DERIVE A COMPANY'S ESTIMATED RATE OF RETURN ON EQUITY?

A. Yes. There is no direct, observable way to determine the rate of return required by equity investors in any company or group of companies. Investors must make do with indications from market data and analyst predictions to estimate the appropriate price of a share. The principal and most reliable methodology for obtaining these indications is the DCF Model. Other procedures, such as the CEA and the CAPM, are less reliable than the DCF Model in my opinion.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODEL IS SUPERIOR TO THE CEA AND CAPM APPROACHES.

[50] Pa. P.U.C. v. UGI Utilities – Electric Division, Opinion and Order at 119, Docket No. R-2017-2640058 (Oct. 25, 2018).

A. The DCF Model is an investor-driven model that incorporates current investor expectations based on daily and ongoing market prices. When a situation develops in a company that affects its earnings and/or perceived risk level, the price of the stock adjusts to reflect those developments. Since the stock price is a major component in the DCF Model, the change in risk level and/or earnings expectations is captured in the investor return requirement with either an upward or downward movement.

The CEA is based on earned returns from book equity, not market equity, as well as a comparison of what other commissions or Commissions across the country are awarding regulated utilities. There is no direct and immediate stockholder input into the CEA and, as a fault, that model lacks a clear and unmistaken link to stockholder expectations.

The CAPM suffers, in my opinion, from the same inherent issues as found within the CEA in that there is not a direct and immediate link from stock market prices to the CAPM result. The Beta in the CAPM can reflect changes in the ROE, but the delay can oftentimes make the CAPM results of little-or-no value.

Q. WHY DID YOU NOT USE THE RISK PREMIUM MODEL?

A. The Risk Premium Model is very similar in nature to the CAPM. In both models, one examines risk premiums, but from varying comparison points. The CAPM considers the risk premium relative to the risk-free rate whereas the risk premium model often develops the risk premium relative to utility bond yields.

Q. COULD YOU PERFORM A COST OF EQUITY ANALYSIS DIRECTLY ON CPA?

A. No. CPA is ultimately a subsidiary of NiSource. Note however that while NiSource is classified as a natural gas utility by *Value Line* within their industry groupings, it is also considered to be a holding company, rather than a natural gas utility like CPA.

A. Discounted Cash Flow ("DCF") Model

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

A. The DCF Model is a widely used method for estimating an investor's required return on a firm's common equity. I have worked within the utility industry since 1984. In my experience, first with the Public Staff of the North Carolina Utilities Commission, and later as a consultant, I have seen the DCF Model used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses and other intervenor witnesses have used the DCF Model, either by itself or in conjunction with other methods such as the CEA or the CAPM, in their analyses.

The DCF Model is based on the concept that the price which the investor is willing to pay for a stock is the discounted present value (*i.e.*, its present worth) of what the investor expects to receive in the future as a result of purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation is only realized when the investor sells the stock, and subsequent purchasers are presumably also focused on dividend growth following their purchase of the stock. Mathematically, the relationship is:

Let D = dividends per share in the initial future period
g = expected growth rate in dividends
k = cost of equity capital
P = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{(1+k)} + \frac{D\,(1+g)}{(1+k)^2} + \frac{D\,(1+g)}{(1+k)^3} + \ldots\ldots + \frac{D\,(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay *today* for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k - g}$$

Solving for k yields:

$$k = \frac{D}{P} + g$$

Q. DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Yes, I believe that they do. There are two primary reasons for my conclusion. First, there is much literature that supports the fact that, while emotional or so-called "irrational" behavior in the short term may affect (and has affected) share prices, over the long term, a company's financial fundamentals drive the market.[51] Secondly, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients.

[51] See, for example, "*Valuation: Measuring and Managing the Value of Companies*", 4th Edition, McKinsey & Company Inc., Tim Koller, Marc Goedhart, David Wessels ("Provided that a company's share price eventually returns to its intrinsic value in the long run, managers would benefit from using a discounted-cash-flow approach for strategic decisions. What should matter is the long-term behavior of the share price of a company, not whether it is undervalued by 5 or 10 percent at any given time." http://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/do-fundamentalsor-emotionsdrive-the-stock-market (Date Accessed March 2, 2016). See also, for example, http://www.businessinsider.com/what-drives-the-stock-market-2012-8 (Date Accessed March 2, 2016).

Thus, in today's market environment, investors will likely calculate (or seek a calculation of) the amount of funds they will receive relative to the initial investment, which is defined as the current dividend yield, as well as the amount of funds that the investor can expect in the future from the growth in the dividend. The combination of the current dividend yield and the future growth in dividends is central to the basic tenet of the DCF Model.

Q. IS THE DCF FORMULA STRAIGHTFORWARD?

A. Yes. While the DCF formula as outlined above may appear complicated, it is a relatively straightforward model. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield, which they expect to receive in the future, to the expected growth in dividends over time.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. If investors expect a current dividend yield of 5%, and also expect that dividends will grow at 4%, then the DCF model indicates that investors would buy the utility's common stock if it provided an ROE of 9%.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected to be paid over the next 12 months for each comparable company, as reported by the *Value Line Investment Survey*. The period covered is from March 26, 2021, through June 18, 2021. To study the short-term, as well as long-term, movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for my comparable group. These results appear in **Exhibit KWO-2** and show an average dividend yield for the 13-week period of 3.2%, the 4-week period of 3.3%, and the 1-week period of 3.2% for the comparable company proxy group. I have also presented the results for NiSource within **Exhibit KWO-2** as CPA's parent company. The values for NiSource over these same periods were 3.5%, 3.5%, and 3.4%, respectively.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELD RANGES DISCUSSED ABOVE.

A. I developed the dividend yield range for my comparable company proxy group by averaging each company's *Value Line* forecasted 12-month dividend yield over the above-stated periods, as well as examining the most recent forecasted 12-month dividend yield reported by *Value Line* for each company. I averaged the dividend yield over multiple time periods in order to minimize the possibility of an isolated event skewing the DCF results.

Q. HOW DID YOU DERIVE THE EXPECTED DIVIDEND GROWTH RATE?

A. I used several methods in determining the growth in dividends that investors expect. These methods are, (1) historical EPS, DPS, and BPS growth rates, (2) forecasted EPS, DPS, and BPS growth rates, and (3) the plowback ratio.

Q. PLEASE DESCRIBE THE FIRST METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. A key component in the DCF Model is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Model, the analyst must consider how dividends are created. Since over the long-term, dividends cannot be paid out without a corporation first earning the funds paid out, earnings growth is a key element in analyzing what if any growth can be expected in dividends. Similarly, what remains in a corporation after it pays its dividend is reinvested, or “plowed back”, into a corporation in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a corporation’s expected dividend growth.

Therefore, to analyze the expected growth in dividends, I believe the analyst should also examine the historical record of past earnings, dividends, and book value. Hence, the first method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year compound annual rates of change for earnings per share (“EPS”), dividends per share (“DPS”), and book value per share

("BPS") as reported by *Value Line* for each of the relevant companies. My reasoning for also utilizing historical growth rates for EPS, DPS, and BPS, rather than solely relying upon forecasted growth rates is that historical growth rates capture the actual growth of the various rates over time based upon a Company's reported results. In contrast, forecasted growth rates are derived <u>entirely</u> from analyst projections, which vary from analyst to analyst, and which also have a tendency to be overstated. As such, I have always found it important to use both historical and forecasted growth rates.

Q. DO ALL ANALYSTS UTILIZE HISTORICAL GROWTH RATES WITHIN THEIR DCF MODELS?

A. No, certain analysts do not present historical growth rates in their DCF analyses. This is true for Mr. Moul as evidenced through his DCF calculations in **Schedule 1** on page 2 of **Exhibit No. 400**, where Mr. Moul only factored forecasted growth rates from **Schedule 9** on page 16 of **Exhibit No. 400** into his DCF analysis. Mr. Moul explained this choice through the following passage of his testimony:

> While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.[52]

[52] Witness Moul's Direct Testimony, page 23: lines 15-20.

While Mr. Moul presented the historical *Value Line* growth rates for his proxy group as of November 27, 2020 on **Schedule 8** on page 15 of **Exhibit No. 400**, nowhere within his DCF calculations does he factor in historical growth rates as explained in the selection from his testimony provided above. I believe that analysts who do not present the readily available historical data fail to provide the full extent of information on which investors base their expectations. While it is true that growth rates are inherently the rate that one would expect a company's stock to grow into future years, both historical growth rates and forecasted growth rates provide valuable data for what one can expect the ultimate growth rate for an individual stock will be. To present the full breadth of the available information, both historical and forecasted growth rates should be used. I believe this to be even more important given the current economic climate and market uncertainty caused by the COVID-19 pandemic. By focusing his entire analysis on forecasted growth rates, Mr. Moul is ignoring the value in historical growth rates that are readily available.

I note that *Value Line* is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor tries to examine all aspects of an enterprise's performance when making a capital investment decision. As such, it is only practical to examine historical growth rates, in addition to the forecasted growth rates, for the corporation on which the analysis is being performed. **Exhibit**

KWO-2 lists the historical and forecasted growth rates for the comparable company proxy group, and **Exhibit KWO-5, page 1** lists the related calculations and results for this method, with the historical and forecasted growth rate values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. Also note that **Exhibit KWO-6**, **page 1** shows these results should this analysis be performed directly on CPA's parent company, NiSource.

Also note that Mr. Moul sourced the historical and forecasted growth rates for his comparable company proxy group as presented in **Schedule 8** and **Schedule 9** of pages 15 and 16 of **Exhibit No. 400**, respectively, from company-specific *Value Line Investment Surveys* from November 27, 2020. However, additional company-specific *Value Line Investment Surveys* for the Natural Gas Industry were made available by *Value Line* on February 26, 2021. Therefore, Mr. Moul not only neglected to use historical growth rates within his DCF Model, but he opted to use forecasted growth rates that were outdated at the time that he filed his testimony on March 30, 2021.

Q. SHOULD ONLY EARNINGS ("EPS") GROWTH RATES BE CONSIDERED IN THE DCF METHODOLOGY?

A. No, I do not believe it is appropriate to strictly rely upon EPS growth rates on either an historical or forecasted basis. Since the DCF formula is dependent on future *dividend* growth, I believe that it would be inaccurate to use only earnings (*i.e.*, EPS) growth rates in the DCF. Doing so would produce unrealistically high return on equity numbers that cannot be sustained indefinitely, which I provide evidence for and discuss in greater detail below within **Section VII-A**: "Review of Moul's DCF Analysis".

To mitigate this problem, I have presented EPS, DPS, and BPS figures and have explained my rationale for arriving at the corresponding growth rates. I believe it is incumbent upon every analyst to present such a robust analysis.

Q. PLEASE DESCRIBE THE SECOND METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. The second method I used was forecasted growth rates. I obtained forecasted growth rates from the following data sources:

- Forecasted compound annual rates of change for EPS, DPS, and BPS as provided by *Value Line*;
- Average "plowback" percent retained to common equity as provided by *Value Line*;
- Forecasted 3-year projected rate of change for EPS as recorded by the *Center for Financial Research and Analysis* (*i.e., CFRA*), a publication of *S&P Global Market Intelligence*; and
- Forecasted LT 3-5-year EPS growth rates, as provided by *Charles Schwab & Co (i.e., Schwab).* This forecasted rate of change is not a forecast developed

solely by *Schwab*, but is – instead – a compilation of forecasts by industry analysts.

As such, the data sources referenced above all represent forecasted growth rates, but are sourced from three separate financial evaluation agencies, *Value Line*, *CFRA*, and *Schwab*.

Exhibit KWO-2 lists the forecasted growth rates for the comparable company proxy group and **Exhibit KWO-5, page 1** lists the related calculations & results for this method with the forecasted growth rate values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. Also note that **Exhibit KWO-6**, **page 1** shows these results should this analysis be performed directly on CPA's parent company, NiSource. My ultimate DCF result range can be found on **Exhibit KWO-1**.

Q. PLEASE DESCRIBE THE THIRD METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. The third method I used is an analysis commonly referred to as the "plowback ratio" method. If a company is earning a rate of return ("r") on its common equity, and it retains a percentage of these earnings ("b"), then each year a Company's earnings per share ("EPS") is expected to increase by the product ("br") of its EPS in the previous year. Therefore, br is a good measure of growth in dividends per share. For example, if a company earns 10% on its equity and retains 50% of that 10%

(*i.e.*, with the other 50% of the 10% earnings on equity being paid out in dividends), then the expected growth rate in earnings and dividends is 5% (*i.e.*, 50% of 10%). To calculate a plowback for the comparable group, I used the following formula:

$$g = \frac{br(2019) + br(2020) + br(2021E) + br(2024E\text{-}2026E\ Avg)}{4}$$

The plowback estimates for all companies in the comparable company proxy group can be obtained from *The Value Line Investment Survey* under the title "percent retained to common equity". **Exhibit KWO-2** and **Exhibit KWO-3** list the plowback ratios for each company in the comparable company proxy group. **Exhibit KWO-5, page 2** shows the related calculations and results for this method with the plowback values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. **Exhibit KWO-6, page 2** then shows these related calculations and results for CPA's parent company, NiSource.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A HISTORICAL GROWTH RATE PERSPECTIVE?

A. In terms of the proper dividend growth rate to employ for the comparable company proxy group in the DCF analysis, it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future.

Within **Exhibit KWO-2**, I have presented the complete set of data for the entirety of the comparable company proxy group without any of the companies removed from the comparable company proxy group as published by *Value Line*. The data and calculations shown therein at **Exhibit KWO-2** is the information that my recommendation was developed from.

An examination of the 10-year and 5-year historical growth rates for the comparable company proxy group within this exhibit show a difference between the average earnings and dividend growth rates. For the 10-year history, BPS (6.4%) grew faster than EPS (4.8%) and DPS (5.9%) in the comparable company proxy group.

However, if one were to remove the -1.5% growth rate for Northwest Natural Gas' EPS, the now shown 5.6% EPS return over the past 10 years is much more in line with the 10-year historical DPS of 5.9%. If one were to remove Northwest Natural Gas from the historical rates entirely as presented within **Exhibit KWO-2**, the historical growth rates from *Value Line* for the proxy group ranges from 5.6% (EPS) to 7.1% (BPS) on the 10-year basis and 6.6% (BPS) to 7.7% (DPS) on the 5-year basis. Additionally, the historical growth rates for NiSource ranged from a BPS of -3.0% to an EPS of 2.0% over the 10-year historical period and an BPS of -5.0% to an EPS of 0.5% over the 5-year historical period.

These growth rates indicate that the natural gas utility industry has historically experienced solid and steady growth in earnings, dividends, and book value. The DCF results based on the set of data previously mentioned for the entirety of the proxy group can be found in **Exhibit KWO-5, pages 1-2** and the related results for NiSource can be found in **Exhibit KWO-6, pages 1-2**.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A FORECASTED GROWTH RATE PERSPECTIVE?

A. The forecasts from *Value Line* for the proxy group range from 5.2% (DPS) to 7.8% (BPS). Additionally, the forecasted *Value Line* growth rates for NiSource ranged from 4.5% (BPS and DPS) to 9.5% (EPS).

In addition to the above forecasted *Value Line* growth rates, the average plowback (retained to common equity) growth rate for the proxy group is 4.3% (**Exhibit KWO-2** and **Exhibit KWO-3**), the *CFRA* 3-year forecasted EPS growth rate is 5.8% (**Exhibit KWO-2**), and the *Schwab* LT Growth Rate 3-5 year forecasted EPS growth rate is 5.7% (**Exhibit KWO-2**). These values for NiSource are 3.9%, 5.0%, and 3.5%, respectively.

These growth rates indicate that the natural gas utility industry is expecting solid and steady growth in earnings, dividends, and book value in the future. The DCF results based on the set of data previously mentioned for the entirety of the proxy group can be found in **Exhibit KWO-5, pages 1-2** and the related results for NiSource can be found in **Exhibit KWO-6, pages 1-2**.

Q. HOW DOES THE COVID-19 PANDEMIC IMPACT YOUR COST OF EQUITY FOR CPA IN THIS CASE?

A. I previously outlined the impacts of the COVID-19 pandemic across the overall market as a whole, as well as the utility industry, within **Section II**: "Current State of the Financial Markets".

With regard to CPA, the information used in my analysis herein encompasses the data from the initial onset of the COVID-19 pandemic, as well as the market's recovery that began in Q3 2020 and that continued into 2021. As a result, any change in the growth rates specific to the natural gas utility comparable group are already reflected in the growth rates utilized within my testimony, thereby recognizing that even though the recovery has begun, the US economy has significant headwinds ahead.

Q. PLEASE PROVIDE THE SPECIFIC RESULTS OF YOUR DCF ANALYSIS.

A. The average dividend yield for the comparable company proxy group for the 13-week period was 3.2%, the 4-week time period was 3.3%, and the 1-week period was 3.2%. Additionally, the average dividend yield for NiSource for the 13-week period was 3.5%, the 4-week time period was 3.5%, and the 1-week time period was 3.4%. With the second portion of the DCF analysis relating to growth rates, I note that the historical growth rates range from 4.8% to 6.9% and the forecasted growth rates range from 4.3% to 7.8%. For NiSource, the historical range is from -5.0% to 2.0% and the forecasted range is from 3.5% to 9.5%.

I have included both historical and forecasted growth rate figures within my analysis as previously noted as shown within both **Exhibit KWO-5** and **Exhibit KWO-6** to present the full set of growth rate information applicable within this cost of capital analysis for both my comparable proxy group, as well as CPA's parent company NiSource. **Table 7** below showcases the Dividend Yield Range values from the 13-week, 4-week, and 1-week dividend yield periods, plus the Historical Growth Rates from *Value Line*, the Forecasted Growth Rates from *Value Line*, *CFRA*, and *Schwab*, and the Plowback Growth Rates from *Value Line* for my comparable company proxy group, as well as for CPA's parent company, NiSource.

Table 7: DCF Results

Natural Gas DCF Results: Proxy Group (as sourced from **Exhibit KWO-5**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	8.83%	9.41%	9.75%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	8.37%	9.59%	11.03%
Value Line Plowback Growth Rate Averages + *Value Line* Div Yield Range	7.48%	7.51%	7.54%
Average (Rx)	8.22%	8.84%	9.44%
DCF Results: NiSource Parent Company (as sourced from **Exhibit KWO-6**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	-0.60%	1.79%	4.77%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	6.90%	8.86%	13.02%
Value Line Plowback Growth Rate Averages + *Value Line* Div Yield Range	7.48%	7.51%	7.54%
Average (Rx)	4.59%	6.05%	8.44%

As shown in **Exhibit KWO-1**, I have utilized an ultimate DCF result range of 7.50% to 9.50%. This range was determined based upon a review of the values shown in the table above. My 7.50% to 9.50% range was positioned towards the high end of the range of values shown within **Table 7** above, with the low-end of the range of 7.50% being set below the average of the minimum values for the proxy group (8.22%), and the high-end of the range of 9.50% being set just above the average of the maximum values for the proxy group (9.44%). My reasoning for placing the low- and high-ends of the range below the previously referenced average minimum and maximum values from the table above was given the lower average values attributable to the DCF Results for NiSource, also shown in **Table 7** above. As such, I have placed my overall DCF result at 9.00%, which is above the midpoint of my 7.50% to 9.50% range in order to take into account the higher forecasted growth rates moving forward.

B. Comparable Earnings Analysis ("CEA")

Q. PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS?

A. I have conducted two different Comparable Earnings Analyses. The first examines returns on book value equity for the comparable group. The second examines allowed natural gas utility returns over an extended period of time to evaluate the trend in returns for companies of similar risk. However, as I stated previously, I believe the CEA to be inferior to the DCF Model and that it should be given less weight in the determination of the ROE recommended in this case.

Q. PLEASE DESCRIBE YOUR FIRST COMPARABLE EARNINGS ANALYSIS.

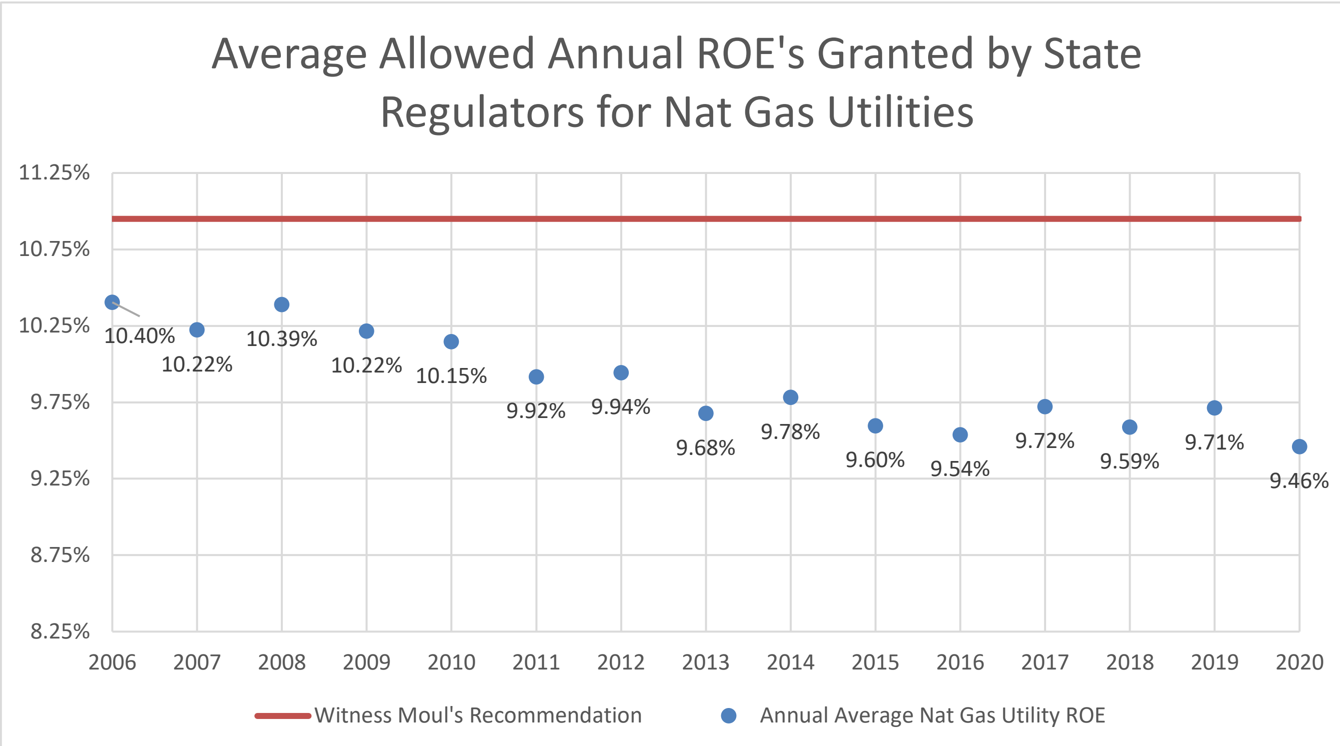
A. As noted above, an appropriate CEA should be applied to comparable companies of similar risk. **Exhibit KWO-4** presents a list of historic and forecasted earned returns *on book value equity* of the proxy group over the period from 2019 through 2026E. I picked this range to provide the Commission with at least two periods of historical returns (*i.e.*, 2019 and 2020) and a forecasted return period of at least 5 years (*i.e.*, 2021E through 2026E). As can be seen in this exhibit, the average earned returns on equity for the comparable company proxy group range from 9.0% (2020) to 9.8% (2021E). Additionally, for CPA's parent company NiSource, this range was from 9.0% (2021E) to 11.5% (2024E – 2026E).

Q. PLEASE DESCRIBE YOUR SECOND COMPARABLE EARNINGS ANALYSIS.

A. It is important to understand what state regulatory commissions/boards across the country are allowing for authorized ROEs. Allowed ROEs are widely known and discussed in the financial community and investors take these regulatory decisions into account when they bid prices in the open market for which they are willing to purchase the stock of a regulated utility.

As this Commission is likely aware, regulated ROE's have trended down over the past 15 years. Below, **Chart 5** shows the ROEs authorized for gas utilities by state regulators across the United States from 2006 through 2020, which ranges from 9.46% (2020) to 10.40% (2006).

Chart 5: Allowed ROEs 2006 – 2020[53]



As for the most recent year, 2020, the overall allowed ROE for gas utilities was 9.46%, which is the lowest figure over the previous 15-year period, significantly down from the 9.71% allowed by state regulators for gas utilities in 2019, and a notable 149-basis points below Mr. Moul's recommendation of 10.95%.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR TWO COMPARABLE EARNINGS ANALYSES?

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[53] *S&P Global Market Intelligence* Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Common Equity to Total Capital, Return on Equity; **Date Accessed**: June 1, 2021.

A. Based on the above-stated findings, I believe the proper rate of return using a CEA is in the range of 9.00% to 10.00%. The 9.00% low end of this range is aligned with the low end of the range of the comparable company proxy group from 2019 – 2026E shown in **Exhibit KWO-4** for 2020 of 9.0%. The 10.00% high end of the range is above the high end of the range of the comparable company proxy group from 2019 – 2026E shown in **Exhibit KWO-4** for 2021E of 9.8%. Note that the ROE granted by state regulators in 2020 of 9.71% (see **Chart 5**) and the average ROE granted by state regulators from 2006 – 2020 of 9.89% fit within this 9.00% to 10.00% CEA range as well.

I have completed the Comparable Earnings Analyses as referenced above to provide the relevant data for the comparable group's book value equity. However, as previously noted, it is my opinion that the DCF Model produces the most reliable results in determining an appropriate ROE. Furthermore, given the current volatile economic climate brought on by the COVID-19 pandemic, the CEA does not appropriately capture the economic impacts of the pandemic within the output of the model. As such, I believe that the CEA should be given much less weight in the determination of the ROE recommended in this case. Additionally, I view the CAPM as a model that is more appropriate to utilize as a check on the results of the DCF Model.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE COMPARABLE EARNINGS BASED ON ALLOWED ROE'S INCLUDED IN EXHIBIT KWO-4 ARE HIGHER THAN THE RESULTS OF YOUR DCF ANALYSIS.

A. As noted above, there has been a clear declining trend in the cost of capital and return on equity figures allowed by utility regulators, and this downward trend is continuing. However, market returns are much more dynamic and change every day. Regulators may not move at the pace of the general market in terms of the decline in the market cost of capital, but regulators are, without a doubt, moving in that direction as exhibited by the decline in the annual allowed return national averages included in the Q&A's above and as exhibited in **Chart 5**.

C. Capital Asset Pricing Model ("CAPM")

Q. HAVE YOU PREVIOUSLY PRESENTED THE CAPM IN COST OF EQUITY TESTIMONIES?

A. Yes, but I have not given it as much weight in comparison to the DCF Model. I have long maintained the application of the CAPM can lead one to erroneous results when it is applied in an inaccurate manner, such as when forecasted risk premiums or forecasted interest rates are employed. However, I am aware that some commissions and boards around the country seek a review of models other than the DCF. As a result, I have included the CAPM in my analyses to supplement my DCF analysis, as well as the CEA to a lesser degree.

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium model that determines a firm's ROE relative to the overall market ROE. The formula for the CAPM is as follows:

$$ROE = Rf + Beta\ [E(RM) – Rf]$$

Where:

Rf is the risk-free rate;

Beta is the risk of the studied company relative to the overall market; and

E(RM) is the expected return on the market.

To be specific, the CAPM is a measure of firm-specific risk, known as unsystematic risk and measured by Beta, as well as overall market risk, otherwise known as systematic risk and measured by the expected return on the market.

The CAPM calculates ROE based on a company's risk and can be restated as follows:

$$ROE = Rf + (Beta * Risk\ Premium)$$

Where:

Risk Premium represents the adjusted company-specific risk of the company.

Q. HOW IS THE RISK-FREE RATE MEASURED?

A. The risk-free rate is designated as the yield on United States government bonds as the risk of default is seen as highly unlikely. Utility witnesses and consumer witnesses all use United States government bond yields as the risk-free rate in the CAPM. However, what is often debated in the risk-free portion of the CAPM is the term of those bonds. In my analysis for this case, I have developed risk premiums relative to the 30-year US Treasury bonds as this time period is the longest available in the marketplace, thereby affording consumers the longest protection at the risk-free rate. **Chart 1**, above, provides the yield on 30-year U.S. Treasury bonds over the period outlined in the chart.

Q. ARE INTEREST RATES, AT THEIR CURRENT LEVEL, EXPECTED TO CHANGE MATERIALLY IN THE FORESEEABLE FUTURE?

A. Economic forecasters, as well as the FOMC, all believed in previous years that the current interest rate environment was expected to remain relatively stable for many years to come. However, the FOMC implemented rate cuts throughout the early stages of 2019 and then, in its December 2019 meeting, announced plans to keep interest rates at current levels throughout 2020.[54] This announcement occurred before the COVID-19 pandemic that played havoc on the markets throughout Q1 and Q2 2020 before the market began to rebound during Q3 and Q4 2020. In

[54] Rugaber, C., *Federal Reserve leaves interest rates unchanged and foresees no moves in 2020*, PBS News Hour (Dec. 11, 2019), available at: https://www.pbs.org/newshour/economy/federal-reserve-leaves-interest-rates-unchanged-and-foresees-no-moves-in-2020.

response to the impact the pandemic had on the market, on March 3, 2020 the FOMC decreased the Federal Funds Rates 50-basis points to a targeted range of between 1% and 1.25% in response to recent market conditions.[55] Additionally, on March 16, 2020 the FOMC dropped interest rates to near 0%.[56] As such, the interest rate market was unexpectedly turbulent during 2020 due largely to the COVID-19 pandemic.

Interest rates fluctuated throughout 2020 based on the overall response to the pandemic, but recently increased above 2.00% during the first half of 2021 (i.e., 2.15% as of June 11, 2021). Despite these changes, the average yield value over the period beginning with the Company's most recently concluded case through the present (*i.e.*, average from April 24, 2020 through June 11, 2021) of 1.74% has still been much lower than that at the conclusion of the Company's most recently concluded rate case prior to 2020,[57] when the 30-year US Treasury Bond Yield on that date was 3.14%.[58] Even with the recent rise in rates above 2.00%, rates are not expected to rise back to levels near 3.14% again at any time in the near term and as such, the market remains in a low overall interest rate environment.

Q. HOW IS BETA MEASURED IN THE CAPM?

[55] https://www.cnbc.com/2020/03/03/fed-cuts-rates-by-half-a-percentage-point-to-combat-COVID-19-slowdown.html
[56] https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a1.htm.
[57] Pa. P.U.C. v. Columbia Gas of Pennsylvania, Docket No. R-2018-2647577, Opinion and Order (12/6/2018).
[58] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

A. Beta is a statistical calculation of a company's stock price movement relative to the overall stock movement. A company whose stock price is less volatile than the overall market will have a Beta less than 1.0. A company whose stock price is more volatile than the overall market will have a Beta more than 1.0. In consideration of the fact that utilities are generally viewed as more conservative equity investments, Betas for utilities are almost always less than 1.0 under normal economic circumstances.

Q. WHAT IS THE CURRENT MARKET RISK PREMIUM APPROPRIATE FOR USE IN THE CAPM?

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. To gauge the historical risk premium, I turned to the Ibbotson database published by *Morningstar, Duff & Phelps,* and the *CFA Institute Research Foundation*. In **Table 8** below, I have presented <u>both the long-term geometric mean and arithmetic mean returns</u> for equities and fixed income securities and the resulting risk premiums.

Table 8: Equity Risk Premium Calculations[59]

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.7%	12.1%
Long-Term Govt. Bonds	8.0%	8.7%
Resulting Risk Premium	2.7%	3.4%

Source: Ibbotson ® SBBI ®, 2020 Classic Yearbook: Stocks, Bonds, Bills and Inflation, 1972 – 2019 (Chicago: Morningstar, 2020).

Note that the data from **Table 8** above shows the statistics of annual total returns for large company stocks and long-term government bonds from 1972 to 2019. With this data being more recent than similar data provided by other sources and analysts over the period from 1926 to 2019, this data adds more credence to what a reasonable investor can expect for a return based upon more historically recent data.

Q. WHAT MARKET RETURNS ARE REPUTABLE PROFESSIONAL INVESTORS EXPECTING FOR THE FORESEEABLE FUTURE?

A. On January 20, 2021, *Morningstar.com* published an article entitled "*Experts Forecast Stock and Bond Returns 2021 Edition.*"[60] This article was provided as part of *Morningstar's* annual stock and bond return forecast series. Note that by referring to future returns, the market experts referenced below are discussing the overall total market returns, and not just the equity risk premium. Below are some of the market return forecasts from the previously referenced article:

[59] https://www.cfainstitute.org/-/media/documents/book/rf-publication/2020/rf-sbbi-summary-edition.ashx
[60] https://www.morningstar.com/articles/1018261/experts-forecast-stock-and-bond-returns-2021-edition

<u>Blackrock</u>

5% 10-year expected nominal return from US equities.[61]

<u>Grantham Mayor Van Otterloo ("GMO")</u>

Negative 5.8% real (inflation-adjusted) returns for US large caps over the next seven years.[62]

<u>JP Morgan</u>

4.1% nominal returns for US equities over a 10–15-year horizon.[63]

<u>Morningstar Investment Management</u>

Negative 0.1% 10-year nominal returns for US stocks.[64]

<u>Research Affiliates</u>

2% nominal (negative 0.2% real) returns for US large caps during the next 10 years.[65]

<u>Vanguard</u>

Nominal US equity market returns of 3.7% to 5.7% range over the next decade.[66]

The above-stated equity returns display a very large range. On the low side is *GMO*, which forecasts that US large caps will, after inflation, lose 5.8% of their value annually over the next seven years. On the more positive side is *Vanguard* that

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[61] *Id.*
[62] *Id.*
[63] *Id.*
[64] *Id.*
[65] *Id.*
[66] *Id.*

expects nominal equity market returns ranging between 3.7% and 5.7% over the next decade. Note that the above forecasts were provided in January 2021, approximately 10 months after the beginning of the pandemic in March 2020.

As another point of reference, *Charles Schwab* published an article on May 3, 2021 titled "*Why Market Returns May be Lower and Global Diversification More Important in the Future*".[67] This article noted that "Market returns on stocks and bonds over the next decade are expected to fall short of historical averages"[68] and that *Schwab's* "estimates show that, over the next 10 years, stocks and bonds will likely fall short of their historical returns from 1970 to December 2020. The estimated annual expected return for U.S. large-capitalization stocks from January 2021 to December 2030 is 6.6%, for example, compared with an annualized return of 10.8% during the historical period."[69] This article also includes a chart that shows the overall market return, and overall market premium, for US large capitalization stocks are expected to be 6.6% and 4.5%, respectively, and that the same figures for US small capitalization stocks are expected to be 7.1% and 5.0%, respectively.[70]

I also note that in 2018, and prior to the COVID-19 pandemic, Duke University finance professors published equity risk premium estimates that stated

[67] https://www.schwab.com/resource-center/insights/content/why-market-returns-may-be-lower-in-the-future
[68] *Id.*
[69] *Id.*
[70] *Id.*

the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country was expected to be 4.42%.[71] The study states the following:

> During the past 18 years, we have collected almost 25,000 responses to the survey. Panel A of Table 1 presents the date that the survey window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk the historical risk premiums contained in Table 1. <u>The current premium, 4.42%, is above the historical average of 3.64%</u>. The December 2017 survey shows that the expected annual S&P 500 return is 6.79% (=4.42%+2.37%) which is slightly below the overall average of 7.11%. The total return forecasts are presented in Fig. 1b.2.[72]

Q. WHAT IS YOUR CONCLUSION AS TO THE ESTIMATED EQUITY RISK PREMIUM FOR USE IN THE CAPM?

A. Using historical data, as well as ex ante (forecast) data, the evidence would suggest the equity risk premium is within the range of 4.25% to 6.25%.

Q. HOW DID YOU DETERMINE THE BETA YOU USED IN THE CAPM?

A. I used the *Value Line* derived Beta sourced from the most recent *Value Line* editions for each company in the comparable company proxy group.

Q. WHAT WERE YOUR CAPM RESULTS?

[71] "The Equity Risk Premium in 2018," John R. Graham and Campbell R Harvey, Duke University, March 28, 2018, pages 3-4.
[72] *Id*., pages 3-4. (underlined emphasis added)

A. The actual calculations for the CAPM for my comparable company proxy group can be seen in **Exhibit KWO-7**.

As shown above in **Chart 1**, I provided the change in the 30-year US Treasury bonds since the beginning of CPA's most recently concluded rate case (*i.e.*, April 24, 2020 – June 11, 2021). Note that over this period, the yield on 30-year US Treasury bonds was 1.17% as of April 24, 2020 and was 2.15% as of June 11, 2021. The Maximum value over this period was 2.45%, the Average value was 1.74%, and the Minimum value was 1.17%. Refer above to **Chart 1** for further details.

The average Beta for the comparable company proxy group is 0.90 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a Beta-adjusted risk premium of 3.83% to 5.63%. The 30-year US Treasury yield ("Rf") range of 1.17% to 2.45% is next added to the Beta-adjusted risk premium range of 3.83% to 5.63% to arrive at the comparable company proxy group CAPM result range of 5.0% (3.83% + 1.17% = 5.00%) to 8.1% (5.63% + 2.45% = 8.08%, rounded to 8.1%).

Additionally, the Beta for CPA's parent company NiSource is 0.85 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a Beta-adjusted risk premium of 3.61% to 5.31%. The 30-year US Treasury yield (Rf) range of 1.17% to 2.45% is next added to the beta-adjusted risk premium range of 3.61% to 5.31% to arrive at NiSource's CAPM result range of 4.8% (3.61% +

1.17% = 4.78%, rounded to 4.8%) to 7.8% (5.31% + 2.45% = 7.76%, rounded to 7.8%).

Based on this range of results for the CAPM, as found in **Exhibit KWO-7**, I find the proper ROE derived from the CAPM is in the range of 6.00% to 8.00%. The low-end (6.00%) of this range is above the average of the comparable company proxy group CAPM results using the 4.25% equity risk premium (5.6%) and is also above the average of NiSource's results using the 4.25% equity risk premium (5.4%) as well. The high end (8.00%) of the range is positioned above the average of the comparable company proxy group CAPM results using the 6.25% equity risk premium (7.4%) and is also above the average of NiSource's results using the 6.25% equity risk premium (7.1%) as well.

D. Return on Equity ("ROE") Summary

Q. MR. O'DONNELL, PLEASE SUMMARIZE THE RESULTS OF YOUR ROE ANALYSES IN THIS CASE.

A. **Table 9** below lists the results of my DCF, CEA, and CAPM analyses as outlined within **Exhibit KWO-1**.

Table 9: ROE Method Results

	ROE Results	
Method	Low	High
DCF	7.50%	9.50%
CEA	9.00%	10.00%
CAPM	6.00%	8.00%

Q. WHAT IS YOUR ROE RECOMMENDATION IN THIS PROCEEDING?

A. My recommendation in this case is shown in **Exhibit KWO-1**. This exhibit shows my recommendation that the Commission grant CPA a return on equity of 9.00%. This 9.00% ROE recommendation is above the 8.50% mid-point of my DCF result range, below the low-end of the CEA, and above the high-end of the CAPM results.

Q. WHAT IS YOUR OVERALL RECOMMENDED RATE OF RETURN IN THIS PROCEEDING?

A. The overall rate of return I am recommending is 6.48%, based upon a 50.00% common equity capital structure / 42.12% long-term debt / 7.88% short-term debt capital structure, and an 9.00% ROE / 4.54% long-term cost of debt / 0.85% short-term cost of debt as summarized again in **Table 10**, below.

Table 10: OCA Recommended Overall Rate of Return

Component	Ratio (%)	Cost Rate (%)	Weighted Cost
Long-Term Debt	42.12%	4.54%	1.91%
Short-Term Debt	7.88%	0.85%	0.07%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.48%**

VIII. REVIEW OF COST OF EQUITY ANALYSIS OF WITNESS MOUL

Q. HOW DID MR. MOUL DEVELOP HIS LIST OF COMPARABLE COMPANIES?

A. Mr. Moul developed his comparable company proxy "Gas Group" by first determining which gas utilities were followed by *The Value Line Investment Survey*.[73] However, as previously referenced earlier within my testimony, of the ten Natural Gas Utilities followed by *Value Line*, Mr. Moul opted to remove UGI Corporation ("UGI") from his comparable company proxy group, leaving his comparable company proxy group comprised of nine companies. Mr. Moul explained within his testimony that he:

> …eliminated one company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of size reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and gas generation.[74]

For context, UGI has a diversified business portfolio that, along with the natural gas utility, contains propane, international LPG, energy service, and electric generation. However, Chesapeake Utilities, which Mr. Moul chose to include in his proxy group, also operates a diverse set of businesses that includes "natural gas distribution, transmission and marketing; electric distribution; propane gas

[73] Witness Moul's Direct Testimony, page 4: lines 13 – 18.
[74] Witness Moul's Direct Testimony, page 4: lines 18 – 21.

distribution and wholesale marketing; advanced information services and other related services."[75] As such, for consistency purposes, I did not feel it appropriate to include one diverse company within my proxy group while simultaneously excluding another.

Additionally, in such industries where there are a higher number of such comparable companies (such as the electric utility industry), I have historically taken a deeper look into which companies I believe are more appropriate than others to be included within my proxy group. However, the number of companies within the natural gas industry is dwindling due to a variety of factors that I previously explained within **Section IV**: "Development of Proxy Group". As such, given that none of the ten companies within the Natural Gas industry grouping provided by *Value Line* were undergoing any sort of bankruptcy, legal issues, restructuring, or merger activities at the time when this direct testimony was filed, I utilized the full ten natural gas utilities provided by *Value Line*.

Q. DO YOU CONSIDER THE COMPANY'S RISK TO BE GREATER THAT OF MR. MOUL'S GAS GROUP?

A. No. Within his testimony, Mr. Moul noted that, "Overall, the Company's risk of competition is considerably higher than that faced by many LDC's, including the

[75] https://chpkgas.com/about-us/about-us/#:~:text=Chesapeake%20Utilities%20is%20the%20natural,advanced%20information%20services%20and%20other

members of the Gas Group that I used to measure the Company's cost of equity."[76] Mr. Moul listed the following items within his direct testimony as support for his assertion of CPA's heightened risk:

- Natural gas utilities, in general, must allocate resources to address aging infrastructure issues;[77]
- CPA operates in an area where there are overlapping service territories, which enables other gas utilities to compete with one another for customers. Additionally, Mr. Moul noted that as a result of these overlapping territories, one customer left CPA's system in 2019 and switched to another LDC within the same territory;[78] and
- There are six interstate pipelines across the Company's service territory, which exposes the Company to bypass risk for large volume customers.[79]

Q. DO YOU AGREE THAT ANY OF THE ITEMS LISTED ABOVE AS SOURCED FROM MR. MOUL'S TESTIMONY SUPPORT THAT CPA'S RISK IS ELEVATED ABOVE MR. MOUL'S GAS GROUP?

A. No. First of all, with regard to the investment levels of CPA to address safety and infrastructure regulations / improvements, what Mr. Moul failed to acknowledge is that every single utility in the country has to make substantial investments for

[76] Witness Moul's Direct Testimony, page 7: lines 7 – 9. (underlined emphasis added)
[77] Witness Moul's Direct Testimony, page 6: lines 13 – 18.
[78] Witness Moul's Direct Testimony, page 6: lines 19 – 24 and page 7: line 1.
[79] Witness Moul's Direct Testimony, page 7: lines 1 – 3.

facility and infrastructure upgrades at one point or another. That is part of the inherent risk of operating a business in an industry that is infrastructure intensive.

Notably, when one compares CPA's anticipated net capital expenditures for 2021 of $388,813,000[80] to the planned 2021 amounts of capital expenditures for Mr. Moul's Gas Group provided in Attachment A to Mr. Moul's response to Question No. **OCA-VI-8**, this comparison shows that many of the companies included in Mr. Moul's Gas Group actually plan to have net capital expenditures in 2021 in excess of CPA.

Mr. Moul also referenced the testimony of CPA Witness Mark Kempic (CPA President and COO) as support for the type of infrastructure investment that the Company plans to make for safety and reliability purposes.[81] Accordingly, Mr. Kempic detailed these infrastructure investments within pages 12 – 20 of his direct testimony. However, what is missing from Mr. Kempic's analysis, just as was missing from Mr. Moul's, is how CPA's level of infrastructure investment compares to that of other natural gas utilities. Absent this analysis, I am unsure as to how these infrastructure investments can be used by the Company as support for why they would consider CPA's risk to be higher than that faced by other LDC's, or the members of the Mr. Moul's Gas Group.

[80] Witness Moul's Direct Testimony, page 10, line 2.
[81] Witness Moul's Direct Testimony, page 6: lines 16 – 18.

Furthermore, CPA has a Distribution System Improvement Charge ("DSIC")[82] that further mitigates the risk of plant investment. Therefore, this is just another reason that would indicate that CPA does not operate in a heightened risk environment simply because it is a natural gas utility.

Q. DO ANY OF THE OTHER ITEMS LISTED ABOVE FROM MR. MOUL'S TESTIMONY SUPPORT THE ASSERTION THAT CPA'S RISK IS ELEVATED ABOVE MR. MOUL'S GAS GROUP?

A. No. With regard to CPA's operation within overlapping service territories, the Company claimed that it "operates in a unique situation with overlapping service territories, which enable other gas utilities to compete with one another for customers"[83] as one of the reasons that CPA's "risk of competition is considerably higher than that faced by many LDC's, including the members of the Gas Group".[84] However, within Question No. **OCA-VI-4**, the Company was asked as to how they quantified the number of customers that are at risk of leaving CPA for another natural gas provider and that are located within the overlapping service territory. The response from Mr. Moul was that "The Company cannot quantify the number the customers at risk of leaving for another natural gas provider, since customer do not always share this information with the Company."[85]

[82] Witness Moul's Direct Testimony, page 8: lines 7 – 9.
[83] Witness Moul's Direct Testimony, page 6: lines 20 – 22.
[84] Witness Moul's Direct Testimony, page 7: lines 7 – 8.
[85] Witness Moul's Response to Question No. **OCA-VI-4**.

Additionally, within Question No. **OCA-VI-5**, Mr. Moul was asked if any large customer had ever left CPA and taken service from any of the interstate pipelines referenced within Mr. Moul's direct testimony. Mr. Moul's response was as follows:

> No, however, Columbia has been successful in preventing pipeline bypass by entering into negotiated rate agreements with a select few customers. Columbia did lose a potential new customer in 2011. Lindy Paving built a new asphalt plant in Big Beaver, PA, and after lengthy service and rate negotiations, the customer built their own pipeline to Tennessee Gas Pipeline.[86]

Not only had no customers left CPA and taken service from any of the interstate pipelines referenced by Mr. Moul in his direct testimony, but the Company had to go back a full decade to find any <u>potential</u> customer that opted to purchase natural gas from another interstate pipeline in CPA's service territory.

Additionally, in terms of the bypass risk referenced within Mr. Moul's direct testimony and as outlined above, the best way for a company to avoid bypass risk is for the company to maintain its rates below the economic cost of bypass. Hence, the CPA request in this case does the exact opposite in that it is raising rates on its consumers. I do not believe CPA should raise the alarm of bypass when it has, in its own hands, the ability to be competitive and avoid bypass.

If the Company cannot present any data that supports these related claims made within Mr. Moul's direct testimony, then it cannot legitimately provide such claims as reasons that the Company should receive an ROE commensurate with the

[86] Witness Moul's Response to Question No. **OCA-VI-5**.

Company's own perceived higher risk relative to other LDC's or the companies included within Mr. Moul's Gas Group. Therefore, these are not items that would indicate CPA's risk to be higher than that of other comparable companies.

Q. DOES CPA HAVE A RATE THAT MINIMIZES THE RISK OF BYPASS?

A. Yes, CPA has a Flex rate whereby the Company can negotiate with large loads that may seek service from other LDCs or interstate pipelines. The ability to negotiate the elimination of service price increases for these loads reduces the risk of losing the load and, correspondingly, the risk for CPA as a whole.

Q. WHAT SPECIFIC COST OF CAPITAL MODELS AND METHODS DID MR. MOUL USE IN HIS ANALYSIS OF THE COST OF EQUITY IN THIS PROCEEDING?

A. Mr. Moul used the Discounted Cash Flow ("DCF") Model, the Risk Premium Model ("RP"), the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings Approach ("CE") in this case. Since the CAPM is a risk premium model similar in nature to the Risk Premium model, Mr. Moul is essentially employing a risk-premium model in two forms in his cost of equity analysis in this case.

Q. DO YOU AGREE WITH THE RESULTS GENERATED BY THE METHODS USED BY MR. MOUL THAT WERE USED TO ESTIMATE CPA'S COST OF EQUITY?

A. No. I do not believe the Commission should rely upon Mr. Moul's models for the reasons discussed below. Instead, I recommend that the Commission rely on the results of my application of the DCF Model, with some consideration of the results of the CAPM and CEA as I have set forth above, to estimate the cost of equity for CPA.

A. Review of Mr. Moul's DCF Analysis

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE DCF MODEL AND MR. MOUL'S APPLICATION OF THE DCF?

A. My DCF analysis in this proceeding produced a range from 7.50% to 9.50%. Mr. Moul's DCF result was 13.46%.[87] The primary differences between my application of the DCF Model and Mr. Moul's application of the DCF Model are the following:

- Mr. Moul applied a 14-basis point adjustment referenced in Mr. Moul's **Schedule 7** on page 14 of **Exhibit No. 400** to the average dividend yield for his comparable company proxy group;[88]

[87] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.
[88] Witness Moul's Direct Testimony, page 21: lines 2 – 12.

- Mr. Moul only utilized forecasted growth rates in his analysis as included within his **Schedule 9** on page 16 of **Exhibit No. 400**, rather than performing his analysis utilizing historical and forecasted growth rates;[89] and
- Mr. Moul applied a 217-basis point financial risk adjustment as outlined within **Schedule 10** on page 17 of **Exhibit No. 400**.[90]

Q. DO YOU AGREE WITH MR. MOUL'S METHODS FOR DETERMINING HIS COMPARABLE GROUP'S AVERAGE DIVIDEND YIELD?

A. No. Mr. Moul began his DCF calculations by determining the dividend yield across his comparable group within his **Schedule 7** on page 14 of **Exhibit No. 400**. He sourced this data from *Morningstar.com* and *SNL.com* for the twelve-months ending December 2020. Mr. Moul also noted that to determine the dividend yield within his DCF and Risk Premium Models, he utilized the six-month average for his comparable company proxy group as shown in **Schedule 7** on page 14 of **Exhibit No. 400** rather than the twelve-month or three-month average dividend yields.

Q. DO YOU AGREE WITH MR. MOUL'S 14-BASIS POINT ADJUSTMENT FOR HIS COMPARABLE GROUP'S AVERAGE DIVIDEND YIELD?

[89] Witness Moul's Direct Testimony, page 23: lines 11 – 20.
[90] Witness Moul's Direct Testimony, page 36: lines 3 – 25.

A. No. In reference to the adjustment to the six-month average dividend yield that he utilized in this proceeding, Mr. Moul noted that he:

> …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 fourteen basis points to the six-month average historical yield, thus producing the 3.79% adjusted dividend yield for the Gas Group.[91]

However, other than simply providing the names of these three adjustment methods shown on **Schedule 7** on page 14 of **Exhibit No. 400**, Mr. Moul did not provide any explanation within his testimony as to what these three "different, but generally accepted, manners" constitute or how simply averaging the results of these three methods is any way appropriate. This adjustment is not necessary to perform a DCF analysis, the use of such an adjustment that simply averages the results of these three methods together is not generally accepted as claimed by Mr. Moul, and this adjustment only serves to increase the dividend yield Mr. Moul utilized within this proceeding, as well as his overall DCF result, by 14-basis points.

Q. DO YOU AGREE WITH MR. MOUL'S SOLE USE OF FORECASTED GROWTH RATES IN HIS DCF MODEL AND OMISSION OF HISTORICAL GROWTH RATES?

A. I previously noted in this testimony that I feel that analysts should present both the historical and forecasted growth rates within their DCF analysis for transparency

[91] Witness Moul's Direct Testimony, page 21: lines 8 – 12.

purposes. Mr. Moul did include the historical growth rates for his proxy group within **Schedule 8** on page 15 of **Exhibit No. 400**, but then entirely omitted the use of any historical growth rates within his testimony. As such, he instead placed his full reliance on forecasted growth rates. If Mr. Moul found no use for historical growth rates, then I am unsure of why he felt the need to present these historical growth rates within the schedules include in **Exhibit No. 400** at all. By not utilizing any of the historical growth rate data in conjunction with his use of forecasted growth rates, Mr. Moul has ignored an entire group of data that is readily available.

As I noted previously in this testimony within the discussion of my own DCF results, I believe that it is important for an analyst to consider historical growth rates within their DCF analysis alongside the forecasted growth rates. Historical growth rates capture the actual growth of the various rates over time based upon a Company's reported results and performance. In contrast, forecasted growth rates are derived entirely from analyst projections, which can vary from analyst to analyst, and which also tend to be overstated.

Q. ARE THERE OTHERS WITHIN THE FINANCIAL COMMUNITY THAT CALL INTO QUESTION PLACING FULL RELIANCE UPON FORECASTED GROWTH RATES?

A. Yes. There are various academic articles and journals that specifically call into question the accuracy of earnings predictions and forecasts. For example, in

November 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "Analysts' Conflict of Interest and Biases in Earnings Forecasts" in the *Journal of Finance*. The conclusion of the paper stated:

> . . . it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is <u>little forecastability in earnings, and analysts' estimates tend to be overly optimistic</u>.[92]

I recognize that there are other academic articles and journals that support the opposite viewpoint. However, given the fact that this remains a debated topic within the financial community, I maintain that I find it appropriate to include EPS, DPS, and BPS from both an historical and forecasted perspective, as well as plowback growth rates, and the associated DCF results for each, within my analysis. In contrast, I believe that placing undue reliance upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely.

Q. DO YOU AGREE WITH MR. MOUL'S USE OF FORECASTED GROWTH RATES?

[92] K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* (2003), page 683. (underlined emphasis added)

A. Yes, I do agree with Mr. Moul's use of forecasted growth rates within his DCF Model. However, as shown in **Schedule 9** on page 16 of **Exhibit No. 400**, Mr. Moul sourced his forecasted growth rates from a date of November 27, 2020[93] from *Value Line*, and a date of January 3, 2021 for *Yahoo Finance* and *Zacks*. The values sourced by Mr. Moul for his forecasted growth rates were between three and four months old by the time that his testimony was filed and ignored the continued changes seen within the market during Q1 2021 prior to the Company's base rate case filing on March 30, 2021. Solely from a *Value Line* perspective, *Value Line* publishes company-specific metrics and forecasts by industry on a quarterly basis. Mr. Moul's testimony utilized data from November 2020 and was never updated for the data published by *Value Line* during February 2021 prior to the filing of his testimony at the end of March 2021.

If an analyst places full reliance on forecasted growth rates, as opposed to basing any of their analysis on historical growth rates, I would contest that utilizing forecasts that are between three and four months old by the time that one's testimony is filed would not be the most prudent of measures.

Q. DO YOU AGREE WITH MR. MOUL'S USAGE OF THE 217-BASIS POINT LEVERAGE ADJUSTMENT?

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[93] Note that **Schedule 9** on page 16 of Mr. Moul's **Exhibit No. 400** references that the *Value Line* information present within that schedule was sourced from "November 27, 2021". However, this reference should read "November 27, 2020".

A. No. This adjustment stems from Mr. Moul's apparent belief that investors are unaware of debt on the Company's books and, therefore, they must be compensated for the additional risk. To this point, Mr. Moul explains:

> 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.[94]

Q. DO YOU AGREE WITH MR. MOUL'S STATEMENT THAT HIS 217-BASIS POINT LEVERAGE ADDER IS NOT A MARKET-TO-BOOK RATIO ADJUSTMENT?

A. No. Mr. Moul's leverage adjustment is a market-to-book ratio adder that inflated his DCF results.

I have been providing ROE testimony to state regulatory bodies for over thirty-four years. I have seen Mr. Moul's market-to-book ratios in years past. In these other applications, the proposed ROE was adjusted upwards to account for a <u>market value that was less than the book value</u>. In the current case, Mr. Moul proposes a similar upward adjustment to his proposed ROE because utility <u>market values are higher than book values</u>. Hence, I have seen this market-to-book adjustment used to raise the recommended ROE in times when market values were above and below the book values. Such an adjustment serves only one purpose, and that is to raise the recommended ROE for the utility client.

[94] Witness Moul's Direct Testimony, page 30: lines 2 – 6.

In this case, Mr. Moul's leverage adjustment is, without a doubt, a market-to-book adjustment that should be summarily dismissed by the Commission as an attempt to justify an unreasonable return on equity for the Company.

Q. HAS THIS COMMISSION PREVIOUSLY RULED ON THE MERITS OF MR. MOUL'S "LEVERAGE" ADJUSTMENT?

A. Yes. In a discovery reply, Mr. Moul noted that he has proposed a leverage adjustment within his DCF and CAPM models in thirty-two different cases on behalf of a Pennsylvania public utility in the past ten years.[95] Notably however, Mr. Moul also stated that he was not aware of any Commission cases within the past ten years in which the Commission approved one of his leverage adjustments.[96] In regard to historical precedence for this Commission over this leverage adjustment, in the 2012 PPL rate case, the Commission determined the following:

> The fact that we have granted leverage adjustments in a few select cases in the past as noted by PPL does not mean that such adjustments are warranted in all cases. The award of such an adjustment is not precedential but discretionary with the Commission. In fact, the Commission has rejected leverage/financial risk adjustments that are similar to the one proposed by PPL in this proceeding. See, e.g., Pa. PUC v. Aqua Pennsylvania, Inc., Docket No. R-00072711, at 38-39 (Order entered July 31, 2008). Moreover, in the context of our determination, supra, of a reasonable return on equity for PPL of 10.28%, we conclude that there is no need to have an artificial upwards adjustment to compensate for any perceived risk related to PPL's market-to-book ratio. Accordingly, we shall deny the

[95] Witness Moul's response to Question No. **OCA-III-16**.
[96] Witness Moul's response to Question No. **OCA-III-17**.

> Exceptions of PPL and adopt the ALJ's recommendation to reject PPL's requested leverage adjustment.[97]

B. Review of Mr. Moul's CAPM Analysis

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE CAPM AND MR. MOUL'S APPLICATION OF THE CAPM?

A. My CAPM analysis in this proceeding produced a range from 6.00% to 8.00%. Mr. Moul's CAPM result was 12.67%.[98] The primary differences between my application of the CAPM and Mr. Moul's application of the CAPM are the following:

- Mr. Moul utilized a "leverage" adjustment on his betas within his CAPM that inflated the average Beta value for his comparable company proxy group from 0.87[99] to 1.10[100];
- Mr. Moul utilized certain data points for his forecasted market return that inflated the overall market return used within his CAPM analysis;[101] and
- Mr. Moul employed a size adjustment of 1.02% to his CAPM results based on his opinion that an adjustment was required to account for the size of CPA as a firm and the associated risk.[102]

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[97] Pa. PUC v. PPL Electric Utilities Corp., Dkt No. R-2012-2290597, Order p. 91 (2012). Available at http://www.puc.pa.gov/pcdocs/1206360.docx
[98] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.
[99] Witness Moul's Direct Testimony, page 35: line 12.
[100] Witness Moul's Direct Testimony, page 36: line 8.
[101] Witness Moul's Direct Testimony, **Schedule 13** of **Exhibit No. 400**.
[102] Witness Moul's Direct Testimony, page 38: line 15.

Q. PLEASE EXPLAIN HOW MR. MOUL APPLIES THE CAPM.

A. In his analysis (as shown on **Schedule 13** of **Exhibit No. 400**), Mr. Moul combined forecasted and historical market premiums, in conjunction with his estimated risk-free rate and re-leveraged Betas, to apply within his CAPM. Mr. Moul's decision to use certain forecasted values ultimately resulted in higher a CAPM result for his client in this proceeding.

Q WHAT IS THE RISK-FREE RATE THAT MR. MOUL USES IN HIS CAPM ANALYSIS?

A. In his direct testimony, Mr. Moul cited various historical and forecasted interest rates and then concluded that 2.00% is a proper estimate for the risk-free rate in the CAPM.[103]

Q. DO YOU AGREE WITH MR. MOUL'S FORECASTED RISK-FREE RATE?

A. I do not take issue with the risk-free rate used by Mr. Moul in this proceeding of 2.00%.[104] As shown within **Exhibit KWO-7**, I have used the 30-year US Treasury Bond Yield to approximate what I deem to be appropriate to use for the risk-free rate for application within the CAPM. This yield over the period from April 24, 2020 – June 11, 2021 ranged from 1.17% to 2.45%, with an average of 1.74%.

[103] Witness Moul's Direct Testimony, page 37: lines 10 – 11.
[104] *Id.*

Q. DO YOU AGREE WITH MR. MOUL'S BETAS USED WITHIN HIS CAPM ANALYSIS?

A. No. As shown within Mr. Moul's **Schedule 3** on page 6 of **Exhibit No. 400**, the average Beta used for Mr. Moul's nine company proxy group is 0.87[105] based on the Betas provided by the company specific *Value Line Investment Surveys* dated November 27, 2020. However, Mr. Moul contended that "…Value Line betas cannot be used directly in the CAPM…"[106] and that therefore he unleveraged and then releveraged the *Value Line* Betas using the Hamada formula.[107] It is through this adjustment that Mr. Moul inflated the average Beta value for his comparable company proxy group for use within his CAPM from 0.87 to 1.10.[108]

Q. WHY DO YOU DISAGREE WITH MR. MOUL'S RELEVERAGED BETAS?

A. Beta, in its simplest form, is used to indicate the volatility of a particular security in reference to a standard benchmark, such as the *NYSE Composite Index* or *S&P 500 Index*. In theory, the closer a particular security's Beta gets to 1.00, the more closely that the risk of that security approximates the risk of the chosen market benchmark. *Value Line* calculates the Beta provided for each of the companies they

[105] Witness Moul's Direct Testimony, page 35: line 12.
[106] Witness Moul's Direct Testimony, page 35: lines 16 – 17.
[107] Witness Moul's Direct Testimony, page 35: lines 18 – 21.
[108] Witness Moul's Direct Testimony, page 36: line 8.

follow by first performing a regression analysis "…of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years."[109]

However, *Value Line* then adjusts these such historical Betas to account "for their long-term tendency to converge toward 1.00"[110]. This adjustment employed by *Value Line* is termed the "Blume Adjustment." The Blume Adjustment first takes the unadjusted Betas that reflect the historic volatility of a security to the overall volatility of the chosen market benchmark and then adjusts them to produce forecasted Betas based on the nature of the Betas for the individual securities to revert back to 1.00 (*i.e.*, the overall average volatility of the chosen market benchmark) over time.[111] As such, the unadjusted historical Beta values provided by *Value Line* for each of the utilities included within their Natural Gas Utility industry grouping have already been adjusted to represent what *Value Line* would deem to be proper forecasts for the Beta values going forward as time progresses.

Through the use of his Beta adjustment included within **Schedule 10** on page 17 of **Exhibit No. 400**, Mr. Moul ultimately utilized an average Beta of 1.10[112] for his comparable company proxy group. This value is 0.23 higher than the *Value Line* adjusted Beta of 0.87 for Mr. Moul's comparable proxy Gas Group and 0.47

[109] https://www.valueline.com/Tools/Educational_Articles/Stocks/Using_Beta.aspx#.X6Fp8IhKiUk
[110] *Id.*
[111] M. Blume, "On the Assessment of Risk," Journal of Finance, March 1971.
[112] Witness Moul's Direct Testimony, page 36: line 8.

higher than the unadjusted historical Beta of 0.63[113] for Mr. Moul's comparable proxy Gas Group. In essence, what Mr. Moul is contending is that although the group of utilities included within his proxy group have historically had an average Beta of 0.63 in comparison to the overall market Beta of 1.00, he believes that the group of utilities included in his proxy group will have a forecasted Beta of 1.10 going forward, and that the average risk attributable to this group of utilities is greater than what will be seen within the entirety of the market.

However, even during the course of a year like 2020 that involved such volatile market fluctuations caused by the COVID-19 pandemic, the Dow Jones Utility Average ("DJUA") has been far less volatile than the Dow Jones Industrial Average ("DJIA"). This helps to showcase that there is nothing to suggest that the risk attributable to a group of gas utilities is projected to be riskier on average than the overall market on a go-forward basis.

As I referenced above, *Value Line* already performs an adjustment upon the historical unadjusted Betas to ensure that the Betas presented through their service are forward looking and prospective. Mr. Moul provided no basis for why his unleveraging and releveraging of the Beta values provided by *Value Line* is warranted other than the fact he felt that the market value Betas provided by *Value Line* should be adjusted to book value Betas. In essence, this is the same flawed

[113] Witness Moul's Direct Testimony, page 36: line 5.

logic that was provided as support for the leverage adjustment applied within Mr. Moul's DCF analysis.

Q. WHAT EXPECTED MARKET RETURN DOES MR. MOUL USE IN THE CAPM ANALYSIS HE EMPLOYS IN THIS CASE?

A. Mr. Moul stated the following in regard to the market premium he utilized:

> For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 11.92% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.88% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 11.92% and the average yield on long-term government bonds of 2.88%. The resulting market premium is 9.04% (11.92% – 2.88%) based on historical data, as shown on Schedule 13, page 2.[114]

As such, Mr. Moul first examined the Historical Market Premium by utilizing the arithmetic mean for the market return from 1926 – 2019 of 11.92% and the risk-free rate over the same period of 2.88% to arrive at a "Historical Market Premium" of 9.04%.

Mr. Moul then calculated two forecasted market premiums as shown within his **Schedule 13** on page 24 of **Exhibit No. 400**. To begin this process, he utilized a "Median Appreciation Potential" of 7.79% and then added a 2.0% "Dividend Yield" (both values provided by *Value Line* on December 25, 2020), to arrive at a

[114] Witness Moul's Direct Testimony, page 37: lines 14 – 21.

9.79% "Median Total Return" to approximate his *Value Line* Forecasted Market Return, which accounted for one half of his "Overall Forecasted Market Return".

He then performed a similar calculation by adding a 9.40% growth rate and a 1.81% dividend yield based on information provided from the *S&P 500* to arrive at an 11.21% value to approximate his *S&P 500* Forecasted Market Return, which accounted for the other half of his "Overall Forecasted Market Return".

Mr. Moul then averaged the 9.79% *Value Line* Forecasted Market Return and the 11.21% *S&P 500* Forecasted Market Return to arrive at an average value of 10.50% to approximate his Overall Forecasted Market Return. Mr. Moul then deducted his 2.00% risk-free rate from the 10.50% to arrive at his "Overall Forecasted Market Premium" of 8.50%.[115]

Q. HOW DID MR. MOUL CALCULATE HIS OVERALL MARKET RISK PREMIUM FOR USE IN THE CAPM?

A. Mr. Moul averaged his "Overall Forecasted Market Premium" of 8.50% and his "Overall Historical Market Premium" of 9.04% to arrive at his overall Market Risk Premium for use within his CAPM of 8.77%.[116]

Q. DO YOU AGREE WITH MR. MOUL'S MARKET PREMIUM ANALYSIS?

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[115] Witness Moul's Direct Testimony, **Schedule 13** of **Exhibit No. 400**.
[116] *Id.*

A. No. I disagree with how Mr. Moul developed his Forecasted Market Premium of 8.50% and his Forecasted Market Return of 10.50%.

As I referenced above, this Forecasted Market Return of 10.50% was developed by Mr. Moul taking the average of his calculated *Value Line* Forecasted Market Return of 9.79% and his calculated *S&P 500* Forecasted Market Return of 11.21%. However, Mr. Moul's inputs he used to develop his Forecasted Market Return data points of 9.79% and 11.21% are highly variable and erratic.

Q. WHY DO YOU CONSIDER THE INPUTS TO MR. MOUL'S *VALUE LINE* FORECASTED MARKET RETURN TO BE HIGHLY VARIABLE?

A. As shown on **Schedule 13** on page 24 of **Exhibit No. 400**, Mr. Moul's *Value Line* Forecasted Market Return of 9.79% is developed from a "Median Appreciation Potential" of 7.79% and "Dividend Yield" of 2.0%. As explained by Mr. Moul within his response to Question No. **OCA-IX-1**, this 7.79% was calculated by Mr. Moul through the following formula $((1 + 0.35)^{1/4} – 1)$.[117] The 0.35 value was sourced from the 35% shown as the "Three to Five Year Price Appreciation Potential" provided by *Value Line* on December 25, 2020. This value approximates the market's overall 3- to 5-year price appreciation potential at that time.

However, such price appreciation potentials vary widely, especially when an anomalous event such as the COVID-19 pandemic occurs. As an example of the

[117] Witness Moul's Response to Question No. **OCA-IX-1**.

variability of the price appreciation potential used by Mr. Moul, the December 25, 2020 *Value Line* as provided by Mr. Moul in the **Attachment A** to his response to Question No. **OCA-IX-1** shows the 35% 3- to 5-year price appreciation potential used by Mr. Moul in this calculation. However, this same *Value Line* edition notes that the 3- to 5-year price appreciation potential was <u>65%</u> "26 weeks" prior to December 25, 2020, was <u>145%</u> during the "Market Low" period on March 23, 2020 and was <u>30%</u> during the "Market High" period on December 8, 2020.[118] These values clearly vary wildly from the <u>35%</u> 3- to 5-year Median Appreciation Potential used by Mr. Moul within his CAPM analysis in this proceeding that ultimately provided him his 7.79% calculated *Value Line* Forecasted Market Premium and *Value Line* Forecasted Market Return of 9.79%.

This showcases a critical flaw with Mr. Moul's use of such data. An analyst should never use such short-term highly variable components such as price potential for determining inputs for any cost of capital analysis.

Q. HOW DOES MR. MOUL'S CALCULATED *VALUE LINE* FORECASTED MARKET RETURN COMPARE TO THAT OF HIS RECENT PREVIOUS TESTIMONIES?

A. In order to showcase the erratic nature of the Median Appreciation Potential input used by Mr. Moul in this proceeding, within **Table 11** below, I have presented a

[118] Witness Moul's Response to Question No. **OCA-IX-1**, **Attachment A**.

comparison of the inputs used by Mr. Moul to develop his *Value Line* Forecasted Market Return within his testimonies for PA Natural Gas rate cases over the time period subsequent to the Company's 2018 rate case.

1 **Table 11**: Mr. Moul's *Value Line* Forecasted Market Return Input Comparison

Company	Docket	Testimony Date	Dividend Yield	Mr. Moul's Calculated Median Appreciation Potential	Mr. Moul's *Value Line* Forecasted Market Return
			a	**b**	**= a + b**
Columbia Gas of Pennsylvania	R-2021-3024296	3/30/2021	2.00%	7.79%	9.79%[119]
PECO Energy Company – Gas Division	R-2020-3018929	9/30/2020	2.40%	13.34%	15.74%[120]
Columbia Gas of Pennsylvania	R-2020-3018835	4/24/2020	2.10%	9.73%	11.83%[121]
UGI Utilities – Gas Division	R-2019-3015162	1/28/2020	2.20%	11.58%	13.78%[122]
Peoples Natural Gas Company	R-2018-3006818	1/28/2019	2.20%	10.67%	12.87%[123]
UGI Utilities – Gas Division	R-2018-3006814	1/28/2019	2.20%	11.58%	13.78%[124]
Columbia Gas of Pennsylvania	R-2018-2647577	3/16/2018	1.90%	5.74%	7.64%[125]

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[119] PA Docket Number R-2021-3024296 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[120] PA Docket Number R-2020-3018929 Witness Moul's Direct Testimony: **Schedule 13**, page 25 of **Exhibit No. 400**.
[121] PA Docket Number R-2020-3018835 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[122] PA Docket Number R-2019-3015162 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[123] PA Docket Number R-2018-3006818 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[124] PA Docket Number R-2018-3006814 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[125] PA Docket Number R-2018-2647577 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**. Note however, that within this proceeding, rather than taking the average of his 7.64% *Value Line* Forecasted Market Return and 11.83% *S&P 500* Forecasted Market Return to develop his Overall Forecasted Market Return, in this case Mr. Moul simply used his 11.83% *S&P 500* Forecasted Market Return, and suspended the use of his 7.64% *Value Line* Forecasted Market Return, per page 42 of his direct testimony in this case.

As shown in **Table 11** above, the Median Appreciation Potential values calculated by Mr. Moul that were used to compute one of the two data points that developed his Overall Forecasted Market Return in each of the seven cases included in the table above fluctuated wildly over the course of the time periods exhibited above, ranging from 5.74% to 13.34%. It is also important to note that some of these large fluctuations in the table above occurred prior to the COVID-19 pandemic, which shows that even in what would be considered more "normal" times within the financial markets, such figures utilized by Mr. Moul prove to be unreliable.

Mr. Moul's use of this highly variable Median Appreciation Potential input resulted in his calculated *Value Line* Forecasted Market Return values that exceeded or were comparable to Historical Market Returns within the rate cases shown in the table above, and simply should not have been used or relied upon for application within his CAPM within the current proceeding.

Q. WHY DO YOU CONSIDER THE INPUTS TO MR. MOUL'S *S&P 500* CALCULATED FORECASTED MARKET RETURN TO BE HIGHLY VARIABLE?

A. As shown on **Schedule 13** on page 24 of **Exhibit No. 400**, Mr. Moul's *S&P 500* Forecasted Market Return of 11.21% was calculated in the following manner:

(1.73%[126] * 1.0470) + 9.40%. In **Attachment A** to Mr. Moul's response to Question No. **OCA-IX-2**, this 9.40% "g" value represents an *S&P 500* 5-year growth forecast percentage provided by *Morningstar* on December 3, 2020.[127] However, this 9.40% 5-year growth rate forecast used by Mr. Moul directly conflicts with the negative 0.1% 10-year nominal returns for US stocks forecast that was published by *Morningstar* in their January 2021 article entitled "*Experts Forecast Stock and Bond Returns 2021 Edition*" that I referenced previously within this testimony.[128]

Q. HOW DOES MR. MOUL'S CALCULATED *S&P 500* FORECASTED MARKET RETURN COMPARE TO THAT OF HIS RECENT PREVIOUS TESTIMONIES?

A. Within **Table 12** below, I have presented a comparison of the inputs used by Mr. Moul to develop his calculated *S&P 500* Forecasted Market Return utilized within his testimonies for PA Natural Gas rate cases over the time period subsequent to the Company's 2018 rate case to showcase the erratic nature of the growth rate ("g") input.

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[126] Note that within Witness Moul's response to Question No. **OCA-IX-2**, he indicated that the 1.73% value used in this calculation should have instead been 1.65%. This adjustment would lower his *S&P 500* Forecasted Market Return from 11.21% to 11.13%.
[127] Witness Moul's response to Question No. **OCA-IX-2**, Attachment A.
[128] https://www.morningstar.com/articles/1018261/experts-forecast-stock-and-bond-returns-2021-edition

Table 12: Mr. Moul's *S&P 500* Forecasted Market Return Input Comparison

Company	Docket	Testimony Date	D/P	1+.5g	g	Mr. Moul's Calculated *S&P 500* Forecasted Market Return
			a	**b**	**c**	**= (a * b) + c**
Columbia Gas of Pennsylvania	R-2021-3024296	3/30/2021	1.73%	1.0470	9.40%	11.21%[129]
PECO Energy Company – Gas Division	R-2020-3018929	9/30/2020	2.03%	1.0200	4.00%	6.07%[130]
Columbia Gas of Pennsylvania	R-2020-3018835	4/24/2020	1.86%	1.0350	7.00%	8.93%[131]
UGI Utilities – Gas Division	R-2019-3015162	1/28/2020	1.96%	1.0480	9.60%	11.65%[132]
Peoples Natural Gas Company	R-2018-3006818	1/28/2019	1.88%	1.0550	11.00%	12.98%[133]
UGI Utilities – Gas Division	R-2018-3006814	1/28/2019	1.90%	1.0550	11.00%	13.00%[134]
Columbia Gas of Pennsylvania	R-2018-2647577	3/16/2018	1.84%	1.0495	9.90%	11.83%[135]

[129] PA Docket Number R-2021-3024296 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.

[130] PA Docket Number R-2020-3018929 Witness Moul's Direct Testimony: **Schedule 13**, page 25 of **Exhibit No. 400**.

[131] PA Docket Number R-2020-3018835 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.

[132] PA Docket Number R-2019-3015162 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.

[133] PA Docket Number R-2018-3006818 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.

[134] PA Docket Number R-2018-3006814 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.

[135] PA Docket Number R-2018-2647577 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**. Note however, that within this proceeding, rather than taking the average of his 7.64% *Value Line* Forecasted Market Return and 11.83% *S&P 500* Forecasted Market Return to develop his Overall Forecasted Market Return, in this case Mr. Moul simply used his 11.83% *S&P 500* Forecasted Market Return, and suspended the use of his 7.64% *Value Line* Forecasted Market Return, per page 42 of his direct testimony in this case.

As shown in **Table 12** above, the growth rate ("g") values used by Mr. Moul to compute the second of the two values used to calculate his Overall Forecasted Market Return in each of the seven cases included in the table fluctuated wildly over the course of the time period exhibited above. Mr. Moul's use of this highly variable growth rate input resulted in *S&P 500* Forecasted Market Returns that exceeded or were comparable to Historical Market Returns within the rate cases shown in the table above, and simply should not have been used or relied upon for application within his CAPM in this proceeding.

These values varied significantly over a range from <u>4.00% to 11.00%</u>. Mr. Moul's use of this highly variable growth rate input resulted in his calculated *S&P 500* Forecasted Market Returns that exceeded or were comparable to Historical Market Returns within the rate cases shown in the table above, and simply should not have been used or relied upon for application within his CAPM within the current proceeding.

Q. HOW DOES MR. MOUL'S OVERALL FORECASTED MARKET RETURN COMPARE TO FORECASTS FROM HIS RECENT PREVIOUS TESTIMONIES?

A. Note that the *Value Line* and *S&P 500* Forecasted Market Returns used by Mr. Moul are not market return or market premium figures that have been forecasted by financial agencies. Instead, these returns were calculated by Mr. Moul based on market price appreciation potential values and were dependent upon highly variable inputs sourced from *Value Line* and *Morningstar S&P 500* data as showcased in **Table 11** and **Table 12** above. The decision to select these such inputs is a highly subjective process and is dependent upon whatever narrative the analyst wishes to create in each individual rate case.

As such, within **Table 13** below, I have presented a comparison of the *Value Line* Forecasted Market Return, *S&P 500* Forecasted Market Return, and Overall Forecasted Market Return utilized throughout Mr. Moul's testimonies within PA Natural Gas rate cases in the time period subsequent to the Company's 2018 rate case.

1 **Table 13**: Mr. Moul's Forecasted Market Returns Comparison

Company	Docket	Testimony Date	*Value Line* Forecasted Market Return	*S&P 500* Forecasted Market Return	Overall Forecasted Market Return
			a (above)	**b (above)**	**= (a + b) / 2**
Columbia Gas of Pennsylvania	R-2021-3024296	3/30/2021	9.79%	11.21%	10.50%[136]
PECO Energy Company – Gas Division	R-2020-3018929	9/30/2020	15.74%	6.07%	10.91%[137]
Columbia Gas of Pennsylvania	R-2020-3018835	4/24/2020	11.83%	8.93%	10.38%[138]
UGI Utilities – Gas Division	R-2019-3015162	1/28/2020	13.78%	11.65%	12.72%[139]
Peoples Natural Gas Company	R-2018-3006818	1/28/2019	12.87%	12.98%	12.93%[140]
UGI Utilities – Gas Division	R-2018-3006814	1/28/2019	13.78%	13.00%	13.39%[141]
Columbia Gas of Pennsylvania	R-2018-2647577	3/16/2018	7.64%	11.83%	11.83%[142]

[136] PA Docket Number R-2021-3024296 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[137] PA Docket Number R-2020-3018929 Witness Moul's Direct Testimony: **Schedule 13**, page 25 of **Exhibit No. 400**.
[138] PA Docket Number R-2020-3018835 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[139] PA Docket Number R-2019-3015162 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[140] PA Docket Number R-2018-3006818 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[141] PA Docket Number R-2018-3006814 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**.
[142] PA Docket Number R-2018-2647577 Witness Moul's Direct Testimony: **Schedule 13**, page 24 of **Exhibit No. 400**. Note however, that within this proceeding, rather than taking the average of his 7.64% *Value Line* Forecasted Market Return and 11.83% *S&P 500* Forecasted Market Return to develop his Overall Forecasted Market Return, in this case Mr. Moul simply used his 11.83% *S&P 500* Forecasted Market, and suspended the use of his 7.64% *Value Line* Forecasted Market Return, per page 42 of his direct testimony in this case.

As shown above for the current rate case (R-2021-3024296), Mr. Moul averaged forecasted market returns of 9.79% from *Value Line* and 11.21% from *S&P 500* to arrive at a value of 10.50% to approximate his forecasted overall market return.[143] These data points vary by <u>142</u>-basis points. If one were to examine the previous PA rate case that Mr. Moul filed testimony for in the PECO Energy Company – Gas Division Docket R-2020-3018929 rate case, his *Value Line* and *S&P 500* Forecasted Market Returns differed by <u>967</u>-basis points.

Mr. Moul's testimony in that PECO Energy Company – Gas Division case was filed just 6 months before his testimony in the current case, which just further showcases the highly variable and erratic nature of these data points. Mr. Moul's method of simply averaging these data points together to provide his Overall Forecasted Market Return has inflated his Overall Forecast Market Premium and his ultimate CAPM results.

I also want to state that I am not against an analyst revising the inputs and estimates used in their cost of capital analyses should changes within the market necessitate such changes. However, I do not find it appropriate for an analyst's long term forecasted market returns to drastically fluctuate in the manner exhibited in **Tables 11**, **12**, and **13** as included above over an outlined period of just three calendar years.

[143] Witness Moul's Direct Testimony, **Schedule 13** of **Exhibit No. 400**.

Q. HOW DOES MR. MOUL'S FORECASTED MARKET RETURN COMPARE TO FORECASTS FROM OTHER ANALYSTS?

A. As I indicated previously, well-known entities such as Morningstar and Vanguard forecasted market returns from -0.1% to 5.7% during January 2021.[144] Additionally, *Charles Schwab* published an article that included a chart that showed that the overall market return, and overall market premium, for US large capitalization stocks are expected to be 6.6% and 4.5%, respectively, and that the same figures for US small capitalization stocks are expected to be 7.1% and 5.0%, respectively.[145] Mr. Moul's Forecasted Market Return of 10.50% and Forecasted Market Premium of 8.50%, as referenced above are, to say the least, unrealistic.

Whether the comparison is to forecasts from current day analysts or to historical returns, Mr. Moul's market return forecasts used within his CAPM analysis simply have no underlying fundamental support or reasoning.

Q. HOW DOES MR. MOUL'S FORECASTED MARKET RETURN COMPARE TO WHAT NISOURCE ACTUALLY BELIEVES THE MARKET IS GOING TO EARN AS EVIDENCED IN THEIR PENSION CALCULATIONS?

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[144] https://www.morningstar.com/articles/1018261/experts-forecast-stock-and-bond-returns-2021-edition
[145] https://www.schwab.com/resource-center/insights/content/why-market-returns-may-be-lower-in-the-future

A. According to the Company's response to Question No. **OCA-III-11**, in calculating its pension plan needs, NiSource assumes an 8.25% US Large Cap Equity assumed market return and an 8.75% US Small Cap Equity assumed market return.[146] Clearly, Mr. Moul's forecasted market return of 10.50%[147] is excessive in comparison to what his employer in this case actually believes will occur in the marketplace.

Q. DO YOU AGREE WITH MR. MOUL'S CAPM 102-BASIS POINT SIZE ADJUSTMENT?

A. No. As shown on his **Schedule 1** of **Exhibit No. 400**, Mr. Moul's CAPM result of 12.67% included a size adjustment of 102-basis points.

As mentioned earlier, it is my belief that the CAPM is inferior to the DCF in determining the market required return on equity. Without a direct and immediate link to current stock market prices, the CAPM simply cannot reflect current investor sentiments of the market.

To support his 1.02% (102-basis points) adder, Mr. Moul notes that "…as the size of a firm decreases, its risk and required return increases."[148] As such, he has asserted that a 1.02% adder should be employed to adjust for the size of CPA relative to other firms. Mr. Moul then proceeded to cite as support for this position,

[146] Witness Moul's response to Question No. **OCA-III-11**.
[147] Witness Moul's Direct Testimony, **Schedule 13** of **Exhibit No. 400**.
[148] Witness Moul's Direct Testimony, page 38: lines 4 – 5.

an article from *Public Utilities Fortnightly* from 1995 and an article from *The Journal of Finance* from 1992.[149]

There are two errors in this 102-basis point adjustment. First, it is unclear from Mr. Moul's testimony whether he is saying CPA is "mid-cap" or if he is saying NiSource, its parent company, is "mid-cap." If Mr. Moul is claiming NiSource is mid-cap, I direct him to the February 26, 2021 edition of NiSource's quarterly company-specific *Value Line* publication that has NiSource with a total capitalization of $8.6 billion and states that NiSource is "Large Cap." Hence, no adjustment would be warranted if Mr. Moul is applying his adjustment based on the size of NiSource.

If Mr. Moul is claiming that CPA is "mid-cap", the adjustment would make even less sense as the entire amount of the Company's equity is owned by NiSource, its parent holding company. Since the stock of CPA is not traded publicly, there is no basis for such a large 102-basis point adder.

Second, what Mr. Moul fails to reflect is that investors have already done the requisite research to know at CPA is an inherently smaller utility than those included within his Gas Group or S&P Utility Group. Facts about CPA, such as its size relative to other firms, have already been factored into the price by investors. To the extent investors feel these companies are a higher risk than larger entities,

[149] Witness Moul's Direct Testimony, page 38: lines 7 – 11.

investors will price that premium into the current stock price. Hence, Mr. Moul's 1.02% adder simply double counts any size premium, assuming one exists at all.

Q. HAS THIS COMMISSION PREVIOUSLY RULED ON MR. MOUL'S SIZE RISK ADJUSTMENT ARGUMENT?

A. Yes. Mr. Moul acknowledged proposing a size risk adjustment within his CAPM in thirty-two different cases on behalf of a Pennsylvania public utility in the past ten years.[150] Notably however, Mr. Moul also stated that he was not aware of any Commission cases within the past ten years in which the Commission approved this size adjustment.[151]

Indeed, in the 2018 UGI Utilities – Electric general rate case, the Commission rejected Mr. Moul's leverage and firm size adjustments and stated:

> Finally, we reject UGI's request for a leverage adjustment and a size adjustment in the calculation of the CAPM cost of equity.[152]

The Commission was not persuaded by the technical literature cited by Mr. Moul within this previous case and was not convinced that a size risk adjustment was appropriate for use within a utility setting.

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[150] Witness Moul's response to Question No. **OCA-III-16**.
[151] Witness Moul's response to Question No. **OCA-III-17**.
[152] Pa. P.U.C. v. UGI Utilities – Electric Division, Opinion and Order at 100, Docket No. R-2017-2640058 (Oct. 25, 2018). (underlined emphasis added)

C. Review of Mr. Moul's Risk Premium Method

Q. MR. O'DONNELL, PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE RISK PREMIUM MODEL AND THE CAPM?

A. The CAPM and the Risk Premium models are both essentially risk premium models. The primary difference is the CAPM is more company-specific due to its use of beta to measure systematic risk. However, both models compare market returns (either total market or utility markets) to bond yields.

Q. PLEASE EXPLAIN MR. MOUL'S APPLICATION OF HIS RISK-PREMIUM MODEL.

A. Mr. Moul's risk premium result in this proceeding is 10.00%.[153] In his application of the Risk Premium model, Mr. Moul combined a forecasted utility bond yield and his determination of an appropriate risk premium. To be specific, Mr. Moul combined a forecasted A-rated bond yield of 3.25% (a risk-free rate of 2.00% combined with a yield spread of 1.25%) to a risk premium of 6.75% to derive a 10.00% risk premium result.[154]

Q. DO YOU AGREE WITH MR. MOUL'S PRESENTATION OF THE RISK PREMIUM MODEL?

[153] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.
[154] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.

A. No. First, I disagree with the use of forecasted bond yields. The best predictor of future yields is the current yield curve. If the market feels interest rates are going to increase in the future, it will bid down current bond prices so that yields correspondingly increase. The reverse is also true in that, when the market feels interest rates will soon fall, it will bid up bond prices thereby reducing bond yields.

D. <u>Review of Mr. Moul's Comparable Earnings Approach</u>

Q. PLEASE EXPLAIN THE MANNER IN WHICH MR. MOUL CONDUCTED HIS COMPARABLE EARNINGS APPROACH?

A. My CEA in this proceeding produced a range from 9.00% to 10.00%. Mr. Moul's CEA result was 12.00%.[155] Mr. Moul developed a group of non-regulated companies that he believed were comparable in risk to CPA. Mr. Moul then compared the historical earned returns of these non-regulated companies to the results of his DCF and CAPM analyses which are based on market returns.

Q. DO YOU AGREE WITH MR. MOUL'S COMPARABLE EARNINGS APPROACH?

A. No, I have two areas of disagreement with Mr. Moul in his CEA. First, a non-regulated firm does not operate in a monopoly service territory and does not have the ability to seek higher rates from state regulators when they deem it necessary or

[155] Witness Moul's Direct Testimony, **Schedule 1** of **Exhibit No. 400**.

desirable to do so. Hence, the operation of a regulated utility is inherently different from entities that operate in truly competitive markets. As an example, Mr. Moul included “New York Times Co” and “Scholastic Corporation” as part of the comparable group on which he bases his CEA for CPA, a regulated gas utility. I recognize that New York Times Co. and Scholastic Corporation may have met certain financial benchmarks as determined by Mr. Moul for comparability to CPA to be included within his analysis shown in **Schedule 14** on pages 26 – 27 of **Exhibit No. 400**, but these companies clearly do not operate in businesses that are anything close to the business of a regulated utility. Mr. Moul’s comparable group is simply not comparable to the operation of a regulated gas utility with a monopoly market.

The second area of disagreement I have with Mr. Moul’s CEA is my repeated concern of comparing book value with market value as Mr. Moul continues to conflate book value with market value. Clearly, the two are totally separate entities, and since market values are not well above book values, a return on book values as Mr. Moul espouses will result in returns that are excessive relative to what investors can actually receive in the marketplace. As a result, Mr. Moul’s reliance on book value returns is misguided.

IX. SUMMARY

Q. MR. O'DONNELL, PLEASE SUMMARIZE YOUR TESTIMONY.

A. CPA's requested rate increase in this case is excessive, unnecessary, and burdensome on the ratepayers of Pennsylvania. My specific recommendations in this case are as follows:

- The proper capital structure to use in this proceeding is 50.00% common equity and 50.00% long-term debt;
- I accept the Company's recommended total cost of debt of 4.23%;
- The Company's allowed ROE should be set at 9.00%;
- The overall rate of return that CPA should be allowed to earn in this proceeding is 6.48%; and
- The Company's requested capital structure and ROE are, both, unreasonable for ratemaking purposes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Kevin W. O'Donnell, CFA

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Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst ("CFA").

Mr. O'Donnell has experience working in the electric, natural gas, and water/sewer industries since 1984. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

Mr. O'Donnell has completed close to 30 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in over 110 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, the Wisconsin Public Service Commission, the Maryland Public Service Commission, the District of Columbia Public Service Commission, the Pennsylvania Public Utility Commission, the Indiana Public Utility Commission, the California Public Service Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, asset valuation analyses, fuel adjustments, merger transactions, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly*. Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide.* All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1991	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1991	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1991	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA Corp	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA Corp	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Company	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Progress I	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commission	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina Natur	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natur	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natur	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Group	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Merger analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominon NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure
2018	Duke Energy Carolinas	NC	E-7, Sub 1146	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Elkton Gas/SJI	MD	FC 9475	Maryland Office of People's Counsel	Merger analysis
2018	Entergy Texas	TX	PUC 48371	Entergy Texas Cities	ROE
2018	Duke Energy Carolinas	SC	2018-3-E	South Carolina Energy Users Committee	Fuel case
2018	Elkton Gas Company	MD	FC 9488	Maryland Office of People's Counsel	Accounting, ROE, capital structure
2018	Baltimore Gas & Electric	MD	FC9484	Maryland Office of People's Counsel	ROE, capital structure

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2018	South Carolina Electric & Gas	SC	2017-370-E	South Carolina Energy Users Committee	Creditworthiness issue
2018	Jersey Central Power & Light	NJ	EO18070728	NJ Division of Rate Counsel	ROE and capital structure
2019	Duke Energy Carolinas	SC	2018-319-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Duke Energy Progress	SC	2018-318-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Public Service Electric and Gas	NJ	EO18060629	NJ Division of Rate Counsel	ROE and capital structure
2019	Potomac Electric Power	MD	FC 9602	Maryland Office of People's Counsel	ROE, capital structure
2019	Oklahoma Gas and Electric	OK	PUD 201800140	Sierra Club	Creditworthiness issue
2019	Peoples Natural Gas	PA	R-2018-3006818	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	UGI Natural Gas	PA	R-2018-3006814	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	Dominion Virginia Power	VA	PUR-2019-00050	Federal Executive Agencies	Return on Equity
2019	Piedmont Natural Gas	NC	G-9, Sub 743	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2019	Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric	CA	A-1904014, et al	Federal Executive Agencies	ROE, capital structure
2019	Duke Energy Indiana	IN	Cause 45253	Federal Executive Agencies	ROE, capital structure
2020	Duke Energy Carolinas	NC	E-7 Sub 1214	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Duke Energy Progress	NC	E-2 Sub 1219	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Dominion Virginia Power	VA	PUR-2019-00154	Southern Environmental Law Center	Financial analysis of plant investment
2020	Southwest Electric Power Company	LA	U-35324	Alliance for Affordable Energy	Financial analysis of plant investment
2020	Texas Gas Company	TX	PUC 10928	Texas Gas Cities	ROE, capital structure
2020	Potomac Electric Power	DC	FC 1156	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	UGI Gas	PA	R-2019-3015162	Pennsylvania Office of Consumer Advocate	ROE, capital structure, creditworthiness
2020	Columbia Gas of Maryland	MD	FC 9644	Maryland Office of People's Counsel	ROE, capital structure
2020	Columbia Gas of Pennsylvania	PA	R-2020-3018835	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2020	New Mexico Gas Company	NM	19-00317-UT	Federal Executive Agencies	ROE, captial structure, accounting, rate design, cost of service
2020	Washington Gas Light	DC	FC 1162	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	Dominion Energy South Carolina	SC	2020-125-E	South Carolina Energy Users Committee	Accounting, rate design

OCA Recommended Overall Rate of Return

O'Donnell Financial Analyses ROE Results		
DCF	7.50%	9.50%
CEA	9.00%	10.00%
CAPM	6.00%	8.00%
Recommendation	**9.00%**	

OCA Overall Recommendation			
Component	Capital Structure Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	42.12%	4.54%	1.91%
Short-Term Debt	7.88%	0.85%	0.07%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.48%

O'Donnell Proxy Group
DCF Summary

Company	Forecasted Annualized Dividend Yield			Value Line									Average Plowback Growth	CFRA	Schwab
				10-Year			5-Year			Forecasted (Est'd '18-'20 to '24-'26)				3-Year Projected	LT Growth Rate 3-5 Years
	13-Wks [1]	4-Wks [2]	Current [3]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	Rate [4]	EPS CAGR [5]	EPS (AEE) [6]
													Exhibit KWO-3		
Atmos Energy	2.6%	2.7%	2.6%	8.0%	5.0%	7.5%	9.0%	7.5%	10.0%	7.0%	7.5%	10.5%	4.1%	8.0%	7.2%
Chesapeake Utilities	1.6%	1.7%	1.7%	9.5%	6.5%	9.5%	9.0%	7.5%	11.0%	8.5%	8.0%	6.5%	6.7%	3.6%	-
New Jersey Resources	3.2%	3.1%	3.0%	6.0%	7.0%	7.5%	5.5%	6.5%	8.5%	2.0%	5.5%	5.5%	4.1%	8.0%	6.0%
Northwest Natural	3.6%	3.6%	3.5%	-1.5%	1.5%	1.0%	1.5%	0.5%	-	5.5%	0.5%	8.5%	1.9%	4.0%	3.8%
ONE Gas Inc	3.1%	3.2%	3.2%	-	-	-	10.0%	14.5%	3.0%	6.5%	7.0%	10.5%	3.5%	5.0%	5.0%
South Jersey Inds	5.0%	4.8%	4.6%	1.5%	6.5%	5.5%		4.0%	2.5%	11.5%	4.5%	6.5%	3.6%	6.0%	4.9%
Southwest Gas	3.5%	3.6%	3.6%	7.5%	8.5%	6.0%	5.5%	8.0%	7.0%	9.0%	4.5%	6.0%	4.4%	6.0%	4.0%
Spire Inc	3.5%	3.7%	3.7%	1.5%	4.5%	7.0%	4.5%	6.0%	5.5%	10.0%	4.5%	9.0%	3.2%	4.0%	7.3%
UGI Corp	3.1%	3.0%	2.9%	5.5%	8.0%	7.0%	7.0%	7.5%	5.5%	6.0%	4.5%	7.0%	7.0%	8.0%	7.2%
AVERAGE	**3.2%**	**3.3%**	**3.2%**	**4.8%**	**5.9%**	**6.4%**	**6.5%**	**6.9%**	**6.6%**	**7.3%**	**5.2%**	**7.8%**	**4.3%**	**5.8%**	**5.7%**
NiSource Inc	3.5%	3.5%	3.4%	2.0%	-1.5%	-3.0%	0.5%	-3.0%	-5.0%	9.5%	4.5%	4.5%	3.9%	5.0%	3.5%

Notes:

EPS = earnings per share
DPS = dividends per share
BPS = book value per share
Est'd '18-'20 to '24-'2(

Sources:

[1]	The Value Line Investment Survey, Summary and Index:	3/26/2021	4/2/2021	4/9/2021	4/16/2021	4/23/2021	4/30/2021	5/7/2021	5/14/2021	5/21/2021
		5/28/2021	6/4/2021	6/11/2021	6/18/2021					
[2]	The Value Line Investment Survey, Summary and Index:	5/28/2021	6/4/2021	6/11/2021	6/18/2021					
[3]	The Value Line Investment Survey, Summary and Index:	6/18/2021								
[4]	The Value Line Investment Survey: 5/28/2021 (Nat Gas)									
[5]	CFRA Stock Report earnings estimates as of 5/24/2021 as provided by Schwab.com									
[6]	Schwab Equity Report earnings estimates as of 5/24/2021 as provided by Schwab.com									

O'Donnell Proxy Group
Plowback Ratios

Company	2019	2020	2021E*	2023E* - 2025E* / 2024E* - 2026E*	AVERAGE
					Exhibit KWO-2, Exhibit KWO-5 pg. 2
Atmos Energy	4.6%	4.4%	4.0%	3.5%	4.1%
Chesapeake Utilities	6.5%	6.2%	6.5%	7.5%	6.7%
New Jersey Resources	4.6%	4.3%	4.0%	3.5%	4.1%
Northwest Natural	1.4%	1.7%	2.0%	2.5%	1.9%
ONE Gas Inc	3.8%	3.7%	3.5%	3.0%	3.5%
South Jersey Inds	NMF	2.9%	3.0%	5.0%	3.6%
Southwest Gas	3.9%	4.0%	4.0%	5.5%	4.4%
Spire Inc	2.7%	NMF	4.0%	3.0%	3.2%
UGI Corp	5.6%	7.0%	8.0%	7.5%	7.0%
AVERAGE	**4.1%**	**4.3%**	**4.3%**	**4.6%**	**4.3%**

NiSource Inc	3.8%	3.7%	2.5%	5.5%	3.9%

*E = expected
Plowback = Percent retained to common equity
The Value Line Investment Survey: 5/28/2021 (Nat Gas)

O'Donnell Proxy Group
Returns on Book Value

Company	2019	2020	2021E*	2024E* - 2026E*
Atmos Energy	8.9%	8.6%	8.0%	7.5%
Chesapeake Utilities	10.9%	10.1%	11.0%	12.0%
New Jersey Resources	11.3%	10.6%	10.5%	10.5%
Northwest Natural	7.5%	7.9%	7.5%	7.0%
ONE Gas Inc	8.8%	8.8%	8.5%	6.5%
South Jersey Inds	7.2%	9.8%	10.0%	11.5%
Southwest Gas	8.5%	8.7%	9.0%	10.0%
Spire Inc	7.9%	3.2%	9.5%	7.5%
UGI Corp	10.8%	13.6%	14.0%	12.5%
AVERAGE	**9.1%**	**9.0%**	**9.8%**	**9.4%**

NiSource Inc	9.7%	10.5%	9.0%	11.5%

*E = expected
The Value Line Investment Survey: 5/28/2021 (Nat Gas)

O'Donnell: Proxy Group
DCF Results

O'Donnell DCF Calculation

	VL 13-Weeks a	VL 4-Weeks b	VL 1-Week c
	Exhibit KWO-2 →		
VL DIVIDEND YIELD AVERAGES	3.2%	3.3%	3.2%

Growth Rates	VL EPS d	VL DPS e	VL BPS f
	Exhibit KWO-2 →		
10-Year Growth Rate Averages	4.8%	5.9%	6.4%
5-Year Growth Rate Averages	6.5%	6.9%	6.6%
VL HISTORICAL GROWTH RATE AVERAGES	**5.6%**	**6.4%**	**6.5%**

	VL EPS g	VL DPS h	VL BPS i	CFRA EPS j	Schwab EPS k
	Exhibit KWO-2 →				
FORECASTED GROWTH RATE AVERAGES	**7.3%**	**5.2%**	**7.8%**	**5.8%**	**5.7%**

	13-Weeks VL EPS = a + d	13-Weeks VL DPS = a + e	13-Weeks VL BPS = a + f
	Rx →		
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	8.9%	9.7%	9.7%
	4-Weeks VL EPS = b + d	4-Weeks VL DPS = b + e	4-Weeks VL BPS = b + f
	Rx →		
	8.9%	9.7%	9.8%
	1-Week VL EPS = c + d	1-Week VL DPS = c + e	1-Week VL BPS = c + f
	Rx →		
	8.8%	9.6%	9.7%

	MIN ABOVE →	AVG	MAX
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**8.8%**	**9.4%**	**9.8%**

	13-Weeks VL EPS = a + g	13-Weeks VL DPS = a + h	13-Weeks VL BPS = a + i	13-Weeks CFRA EPS = a + j	13-Weeks Schwab EPS = a + k
	Rx →				
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	10.6%	8.4%	11.0%	9.1%	8.9%
	4-Weeks VL EPS = b + g	4-Weeks VL DPS = b + h	4-Weeks VL BPS = b + i	4-Weeks CFRA EPS = b + j	4-Weeks Schwab EPS = b + k
	Rx →				
	10.6%	8.4%	11.0%	9.1%	8.9%
	1-Week VL EPS = c + g	1-Week VL DPS = c + h	1-Week VL BPS = c + i	1-Week CFRA EPS = c + j	1-Week Schwab EPS = c + k
	Rx →				
	10.5%	8.4%	11.0%	9.0%	8.9%

	MIN ABOVE →	AVG	MAX
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**8.4%**	**9.6%**	**11.0%**

O'Donnell: Proxy Group
DCF Results

O'Donnell DCF Calculation (cont'd)

	VL DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week
	a	b	c
	Exhibit KWO-2		
Atmos Energy	2.6%	2.7%	2.6%
Chesapeake Utilities	1.6%	1.7%	1.7%
New Jersey Resources	3.2%	3.1%	3.0%
Northwest Natural	3.6%	3.6%	3.5%
ONE Gas Inc	3.1%	3.2%	3.2%
South Jersey Inds	5.0%	4.8%	4.6%
Southwest Gas	3.5%	3.6%	3.6%
Spire Inc	3.5%	3.7%	3.7%
UGI Corp	3.1%	3.0%	2.9%
AVERAGE	**3.2%**	**3.3%**	**3.2%**

	VL PLOWBACK
	d
Exhibit KWO-3	
Atmos Energy	4.1%
Chesapeake Utilities	6.7%
New Jersey Resources	4.1%
Northwest Natural	1.9%
ONE Gas Inc	3.5%
South Jersey Inds	3.6%
Southwest Gas	4.4%
Spire Inc	3.2%
UGI Corp	7.0%
AVERAGE	**4.3%**

VL PLOWBACK + VL DIV YIELD AVERAGES		
= a + d	= b + d	= c + d
Rx		
6.8%	6.8%	6.7%
8.3%	8.4%	8.4%
7.3%	7.2%	7.1%
5.5%	5.5%	5.4%
6.6%	6.7%	6.7%
8.6%	8.4%	8.2%
7.8%	8.0%	8.0%
6.8%	6.9%	6.9%
10.1%	10.1%	9.9%
7.5%	**7.5%**	**7.5%**

MIN ABOVE	AVG	MAX
7.5%	7.5%	7.5%

O'Donnell: NiSource Parent Company
DCF Results

O'Donnell DCF Calculation

	VL 13-Weeks a	VL 4-Weeks b	VL 1-Week c
	Exhibit KWO-2 →		
VL DIVIDEND YIELD AVERAGES	3.5%	3.5%	3.4%

Growth Rates	VL EPS d	VL DPS e	VL BPS f		
	Exhibit KWO-2 →				
10-Year Growth Rate Averages	2.0%	-1.5%	-3.0%		
5-Year Growth Rate Averages	0.5%	-3.0%	-5.0%		
VL HISTORICAL GROWTH RATE AVERAGES	**1.3%**	**-2.3%**	**-4.0%**		
	VL EPS g	VL DPS h	VL BPS i	CFRA EPS j	Schwab EPS k
	Exhibit KWO-2 →				
FORECASTED GROWTH RATE AVERAGES	**9.5%**	**4.5%**	**4.5%**	**5.0%**	**3.5%**

	13-Weeks VL EPS **= a + d**	13-Weeks VL DPS **= a + e**	13-Weeks VL BPS **= a + f**
	Rx →		
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	4.8%	1.3%	-0.5%
	4-Weeks VL EPS **= b + d**	4-Weeks VL DPS **= b + e**	4-Weeks VL BPS **= b + f**
	Rx →		
	4.7%	1.2%	-0.6%
	1-Week VL EPS **= c + d**	1-Week VL DPS **= c + e**	1-Week VL BPS **= c + f**
	Rx →		
	4.7%	1.2%	-0.6%
	MIN	**AVG**	**MAX**
	ABOVE →		
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**-0.6%**	**1.8%**	**4.8%**

	13-Weeks VL EPS **= a + g**	13-Weeks VL DPS **= a + h**	13-Weeks VL BPS **= a + i**	13-Weeks CFRA EPS **= a + j**	13-Weeks Schwab EPS **= a + k**
	Rx →				
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	13.0%	8.0%	8.0%	8.5%	7.0%
	4-Weeks VL EPS **= b + g**	4-Weeks VL DPS **= b + h**	4-Weeks VL BPS **= b + i**	4-Weeks CFRA EPS **= b + j**	4-Weeks Schwab EPS **= b + k**
	Rx →				
	13.0%	8.0%	8.0%	8.5%	7.0%
	1-Week VL EPS **= c + g**	1-Week VL DPS **= c + h**	1-Week VL BPS **= c + i**	1-Week CFRA EPS **= c + j**	1-Week Schwab EPS **= c + k**
	Rx →				
	12.9%	7.9%	7.9%	8.4%	6.9%
	MIN	**AVG**	**MAX**		
	ABOVE →				
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**6.9%**	**8.9%**	**13.0%**		

O'Donnell: NiSource Parent Company

DCF Results

O'Donnell DCF Calculation (cont'd)

	VL DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week
	a	b	c
	Exhibit KWO-2		
NiSource Inc	3.5%	3.5%	3.4%

	VL PLOWBACK
	d
Exhibit KWO-3	
NiSource Inc	3.9%

VL PLOWBACK + VL DIV YIELD AVERAGES		
= a + d	= b + d	= c + d
Rx		
7.4%	7.3%	7.3%

MIN	AVG	MAX
ABOVE		
7.3%	**7.3%**	**7.4%**

O'Donnell Proxy Group
CAPM Results

Natural Gas Utility Proxy Comparable Group

	30-Yr. Risk-Free Rate [1]	Average Proxy Group Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.45%	0.90	4.25%	3.83%	6.28%	6.3%	
Treasury - Average	1.74%	0.90	4.25%	3.83%	5.57%	5.6%	
Treasury - Minimum	1.17%	0.90	4.25%	3.83%	5.00%	5.0%	**LOW**

	30-Yr. Risk-Free Rate [1]	Average Proxy Group Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.45%	0.90	6.25%	5.63%	8.08%	8.1%	**HIGH**
Treasury - Average	1.74%	0.90	6.25%	5.63%	7.37%	7.4%	
Treasury - Minimum	1.17%	0.90	6.25%	5.63%	6.80%	6.8%	

Source:
[1] US Treasury Yields, June 11, 2020 through June 11, 2021
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?
[2] The Value Line Investment Survey: 5/28/2021 (Nat Gas)

NiSource

	30-Yr. Risk-Free Rate [1]	NiSource Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.45%	0.85	4.25%	3.61%	6.06%	6.1%	
Treasury - Average	1.74%	0.85	4.25%	3.61%	5.36%	5.4%	
Treasury - Minimum	1.17%	0.85	4.25%	3.61%	4.78%	4.8%	**LOW**

	30-Yr. Risk-Free Rate [1]	NiSource Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.45%	0.85	6.25%	5.31%	7.76%	7.8%	**HIGH**
Treasury - Average	1.74%	0.85	6.25%	5.31%	7.06%	7.1%	
Treasury - Minimum	1.17%	0.85	6.25%	5.31%	6.48%	6.5%	

Source:
[1] US Treasury Yields, June 11, 2020 through June 11, 2021
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?
[2] The Value Line Investment Survey: 5/28/2021 (Nat Gas)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Kevin W. O'Donnell, hereby state that the facts set forth in my Direct Testimony, OCA Statement 2, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 16, 2021
*311185

Signature: ______________________
Kevin W. O'Donnell

Consultant Address: Nova Energy Consultants, Inc.
1350 SE Maynard Road
Suite 101
Cary, NC 27511

OCA Statement No. 2-SR

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2021-3024296**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

SURREBUTTAL TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF

OFFICE OF CONSUMER ADVOCATE

July 27, 2021

Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc ("Nova"). My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I am presenting this surrebuttal testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). The OCA represents consumers before the Pennsylvania Public Utility Commission ("the Commission").

Q. MR. O'DONNELL, DID YOU SUBMIT WRITTEN DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS CASE?

A. Yes. I presented direct testimony as part of the OCA's recommendation in this proceeding.

Q. HAVE YOU REVISED YOUR RECOMMENDED OVERALL COST OF CAPITAL RECOMMENDATION?

A. Yes. First, I have accepted the Company's updated cost of long-term debt of 4.58%.[1] Secondly, I have revised my recommended ratio of long-term debt and short-term debt compared to the overall cost of capital recommendation presented within **Exhibit KWO-1** to my direct testimony. The change is to apportion the debt ratios in line with the

[1] Witness Moul Rebuttal Testimony, Exh. No 400R, page 2, Sch. 2.

Company's requested capital structure and not, as I initially recommended, with debt ratios based on the weighted cost of debt. I believe this change more accurately reflects the debt financing of CPA. I have included this updated recommendation within **Table 1S** below and **Exhibit KWO-1S**:

Table 1S: OCA Overall Recommended Rate of Return[2]

Component	Ratio (%)	Cost Rate (%)	Weighted Cost
Long-Term Debt	45.74%	4.58%	2.09%
Short-Term Debt	4.26%	0.85%	0.04%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.63%**

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. To respond to the rebuttal testimony of CPA Witness Paul R. Moul in relation to his comments on my direct testimony.

Q. PLEASE LIST MR. MOUL'S REBUTTAL TESTIMONY POSITIONS THAT YOU WILL RESPOND TO.

A. In this surrebuttal testimony, I will respond to the following points:

- Mr. Moul's criticism of my recommended capital structure that fairly reflects the Company's financial risk in light of comparable companies;[3]
- Mr. Moul's position that a 10.95% ROE is appropriate for CPA;[4]

[2] Witness O'Donnell's Direct Testimony, Table 2, page 5.
[3] Witness Moul's Rebuttal Testimony, p. 3. 1.2 – p..9, l. 10
[4] Witness Moul's Rebuttal Testimony, page 37: lines 1 – 2.

- Mr. Moul's proposal that the Commission's Quarterly Earnings Report Return on Equity ("ROE") measure for Distribution System Improvement Charge ("DSIC") purposes should serve as a floor in this proceeding;[5]
- Mr. Moul's criticism and misunderstanding of the proxy group as utilized within my direct testimony;[6]
- Mr. Moul's criticism of my discounted cash flow ("DCF") model analysis;[7] and
- Mr. Moul's comments regarding my capital asset pricing model ("CAPM") analysis.[8]

[5] Witness Moul's Rebuttal Testimony: page 11: lines 18 – 22 and page 12: lines 1 – 8.
[6] Witness Moul's Rebuttal Testimony, page 16: lines 11 - page 17: line 6.
[7] Witness Moul's Rebuttal Testimony, page 18: line 6 - page 23: line 15.
[8] Witness Moul's Rebuttal Testimony, page 26: line 16 - page 33, line 12.

II. MR. MOUL'S DISCUSSION OF THE COMPANY'S CAPITAL STRUCTURE

Q. HOW DO YOU RESPOND TO MR. MOUL'S CLAIM THAT YOU NEVER SHOWED HOW THE COMPANY'S PROPOSED CAPITAL STRUCTURE IS UNREASONABLE WITHIN YOUR DIRECT TESTIMONY?[9]

A. Mr. Moul is mistaken on this matter. As Mr. Moul is well aware, the Hope and Bluefield cases established a legal standard and guideline that regulators must follow in determining the cost of capital to grant a utility in a rate case. Within **Tables 4 and 5** to my direct testimony, I compared the CPA requested capital structure, which contained a very high equity ratio of 54.34%, to equity ratios from the following groups:

1. A proxy group of companies with similar risk to CPA for two historical periods and two forecasted periods;
2. The equity ratio of NiSource, which is the parent holding company of CPA, for two historical periods and two forecasted periods;
3. Equity ratios granted by utility regulators to gas utilities across the United States in 2020; and
4. Equity ratios granted by state regulators across the United States over the past 15 years.

Each of the metrics referenced below as set out in **Table 5** to my direct testimony are below the Company's requested common equity ratio in this proceeding of 54.34%. My analysis is far more robust than that which was performed by Mr. Moul, which does not include any such comparison on a national basis.

[9] Witness Moul's Rebuttal Testimony, page 4: line 8.

Q. WHY DO YOU BELIEVE THE COMMISSION SHOULD RECOGNIZE WHAT REGULATORS ACROSS THE COUNTRY ARE GRANTING FOR COMMON EQUITY RATIOS OF NATURAL GAS UTILITIES?

A. I have two reasons. First, investors recognize how regulators around the United States determine the appropriate capital structure for their regulated utilities and price the stock of gas utilities accordingly. As a result, there is a direct link between allowed equity ratios in rate case decisions and the resulting ROE.

Secondly, the Commission should have a base of comparison to how its allowed equity ratio in the capital structure compares to what other state regulators allow in their respective jurisdictions.

I believe that the Commission should be provided as much information as possible for it to make a decision that is in the best interest of CPA and its consumers.

I also believe it is important to point out the inconsistencies in Mr. Moul's testimony on examining positions of other state regulators. On page 29 of his rebuttal testimony, Mr. Moul cites the FERC for using an adjustment to the CAPM due to the size of an entity.[10] However, on page 5 of his rebuttal testimony, Mr. Moul criticized my examination of actions taken and decisions made by other commissions.[11] Simply put, when it is beneficial to his cause, Mr. Moul contends that the Commission should factor in actions taken by other regulatory bodies. However, when it does not support his position, Mr. Moul does not want the Commission to take notice of the actions taken by other regulatory bodies. Clearly, Mr. Moul is being inconsistent in what he is presenting to the Commission.

[10] Witness Moul's Rebuttal Testimony, page 29: line 3 – 5.
[11] Witness Moul's Rebuttal Testimony, page 5: line 3 – 5.

Q. DO YOU AGREE WITH MR. MOUL'S COMPARISON OF THE REQUESTED CPA EQUITY RATIO IN THIS CASE TO ELECTRIC UTILITY COMMON EQUITY RATIOS DATING BACK TO 2012 AND 2018?[12]

A. No. Comparing these past electric utility decisions to the current CPA gas case is mixing apples and oranges. I don't believe such a comparison is timely or relevant.

Q. DO YOU AGREE WITH MR. MOUL'S POSITION THAT THE EQUITY RATIOS ALLOWED IN THE COMPANY'S 2020 AND PECO GAS 2020 RATE CASES JUSTIFY THE COMPANY'S HIGHER EQUITY REQUEST IN THIS PROCEEDING?[13]

A. No, I do not. PECO Energy issues equity on behalf of its gas and electric divisions. CPA is proposing a higher equity ratio (54.34%) compared to the CPA 2020 rate case (54.19%), even though CPA does not issue its own equity and the cost of both long-term and short-term debt through the NiSource money pool has decreased from the last rate case.[14] Indeed, application of an equity ratio equal to PECO Gas' 53.38% would be more favorable to CPA consumers.

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[12] Witness Moul's Rebuttal Testimony, page 5, lines 7 – 9.

[13] Witness Moul's Rebuttal Testimony, page 5, lines 9-12.

[14] CPA 2020 equity ratio of 54.19% versus Witness Moul's proposed 54.34% in this proceeding. CPA 2020 long-term cost of debt of 4.73% compared to 4.58% in this proceeding. CPA 2020 short-term cost of debt of 2.06% compared to 0.85% in this proceeding. Pa. P.U.C. v. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835, Order, Table A (Feb. 19, 2021).

Q. MR. MOUL STATES THAT CPA'S PROPOSED EQUITY RATIO IS WITHIN THE RANGE OF PROJECTED EQUITY RETURNS FOR COMPANIES IN HIS GAS GROUP.[15] PLEASE COMMENT.

A. Although Mr. Moul states this is a test for reasonableness, Mr. Moul did not provide this range information in his direct testimony. Instead, Mr. Moul provided averages based on 2019 financial information in CPA Exhibit 400, Schedule 3 as support. Mr. Moul's Rebuttal provided projected equity ratios for each Gas Group company but without citation.

I examined the individual equity ratios, recent and projected for the *Value* Line Gas Group companies as of *Value Line's* May 28, 2021 Survey in Table 4 in my direct testimony. CPA's proposed 54.34% equity ratio is too high and unreasonable to set rates, even if it is lower than the projected 2021 high point of 57.00% for Chesapeake Utilities.

Q. MR. MOUL PROVIDES REASONS WHY THE COMMISSION SHOULD IGNORE NISOURCE'S PROJECTED CAPITAL STRUCTURE AND COMMON EQUITY RATIO OF 40% FOR THE YEAR 2022.[16] PLEASE COMMENT.

A. I disagree with Mr. Moul's position. In Tables 4 and 5 of my direct testimony, I examined NiSource's capital structure. I have not proposed adoption of NiSource's equity ratio to set rates in this proceeding. Still, the Commission should recognize the gulf between NiSource's lower equity and higher debt ratios compared to those proposed by the Company. Even if some NiSource debt has financed goodwill or other subsidiary

[15] Witness Moul's Rebuttal Testimony, page 4, li. 25-26 through page 5, li. 3.
[16] Witness Moul's Rebuttal Testimony, page 4, li. 25-26 through page 5, li. 1; page 8, li. 12 through page 9, li. 10.

obligations, Mr. Moul has not disproved that NiSource benefits from double leverage with respect to financing CPA's capital needs.

Q. HOW DO YOU RESPOND TO MR. MOUL'S ARGUMENT THAT THE COMPANY'S COST OF DEBT SHOULD BE INCREASED TO REFLECT THE LOWER EQUITY RATIO PROPOSED IN THE OCA TESTIMONY?[17]

A. Mr. Moul is mistaken in this argument. First, the capital structure granted in a regulated case is not the controlling capital structure on which rating agencies base their ratings decisions. The rating agencies look at actual capital structure and not capital structures allowed during rate cases for ratemaking purposes for a utility subsidiary. Secondly, CPA participates in a debt-to-debt arrangement with its parent company, NiSource, whereby NiSource issues debt and provides loans to CPA.

Furthermore, Mr. Moul's argument on the cost of debt actually shows that consumers are overpaying for CPA's cost of debt in the current proceeding. Specifically, NiSource, which has a debt ratio of 60%, has a much higher level of financial risk as compared to that of CPA, which has a debt ratio of 45.66%. Since CPA obtains its debt financing from NiSource, it is actually obtaining its debt capital from a source whose financial strength is inferior to its own financial strength. In doing so, CPA is paying a higher cost of debt than it may otherwise obtain if it went directly into the market for its debt placements. Due to the heavy debt leverage of NiSource, consumers taking monopoly service from CPA are paying a higher

[17] Witness Moul's Rebuttal Testimony, page 6, li.25 through page 7, li. 7.

cost of debt than they would otherwise pay if NiSource's financial leverage was similar to that of CPA.

Q. AFTER REVIEW OF MR. MOUL'S REBUTTAL, WHAT IS YOUR RECOMMENDED CAPITAL STRUCTURE TO SET RATES FOR CPA?

A. I still recommend that the Commission evaluate whether CPA's projected end of the FPFTY capital structure is reasonable and fair to determine an appropriate cost of capital in this proceeding that does not overburden ratepayers. As I explained in my direct testimony, equity is more costly as the dollars collected in rates are subject to taxes. The information contained in **Table 5** to my direct testimony are comparative benchmarks that investors consider when making investment decisions. As such, the equity ratios included within **Table 5** to my direct testimony are more closely aligned with market expectations in this case. I believe that the 54.34% equity capital structure requested by CPA in this case is too heavily weighted towards equity, is not representative of equity ratios found for comparable companies, and is simply too expensive for consumers. My revised capital structure recommendation of 50% equity, 45.74% long-term debt, and 4.26% short-term debt is set forth above and in Exhibit KWO-1S.

If the Commission finds the CPA requested capital structure to be appropriate for ratemaking purposes, I believe the Commission should then recognize in its decision that CPA has lower financial risk due to the higher equity ratio and reduce the allowed ROE accordingly. Specifically, I recommend the Commission grant CPA a ROE below my recommended 9.00% return on equity if it accepts the Company's proposed capital structure that consists of a 54.34% equity ratio.

III. MR. MOUL'S STANCE ON CPA'S INVESTMENT RISK

Q. HOW HAVE THE FINANCIAL MARKETS CHANGED SINCE THE COMPANY'S MOST RECENT RATE CASES?

A. The final order for the previous CPA rate case was issued on February 19, 2021, less than two months before the Company filed its current rate case on March 30, 2021. Even though the equity markets have rebounded strongly since February 19, 2021, Mr. Moul has repeated the same claim that he made in the previous case and asked this Commission to grant his client the same 10.95% ROE.

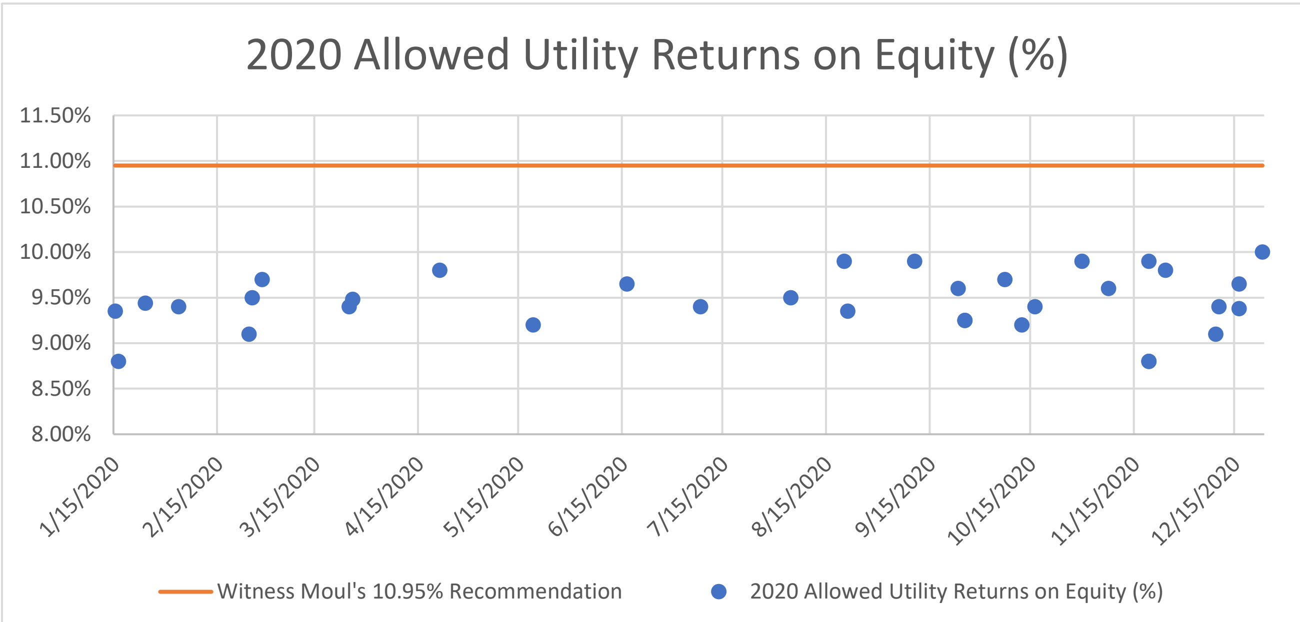
Q. HOW DOES MR. MOUL'S RECOMMENDED ROE OF 10.95% COMPARE TO THE NATIONAL AVERAGE ROE GRANTED BY STATE REGULATORS ACROSS THE COUNTRY DURING 2020?

A. As of the end of 2020, the overall allowed ROE for natural gas utilities was 9.46%, which was down from the 9.71% allowed by state regulators for natural gas utilities in 2019.[18] Mr. Moul's recommended ROE of 10.95% is well above the 9.46% average across the United States in 2020. Additionally, of the 34 completed natural gas cases reported during 2020 that comprised the 9.46% average for the year, there were no rate cases with an

[18] S&P Global Market Intelligence Rate Case Statistics; Frequency: Annually; Date Range: 01/01/2019 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: July 19, 2021.

allowed return higher than 10.00%[19], which is in stark contrast to Mr. Moul's recommended ROE in this case of 10.95%. See **Chart 1S** below for reference:

Chart 1S: 2020 US Allowed Utility Returns on Equity (%)[20]



To-date in 2021, the average allowed ROE has been 9.62% for both litigated and settled rate cases.

Q. HOW DO YOU RESPOND TO MR. MOUL'S CLAIM THAT YOUR RECOMMENDED ROE IS DEFICIENT BASED ON THE VOLATILITY INDEX?[21]

A. I disagree. Within his rebuttal testimony, Mr. Moul claimed that because the Volatility Index ("VIX") averaged 32.21 during 2020 in comparison to 16.33 in 2019, this constituted

[19] S&P Global Market Intelligence Rate Case Statistics; Company List: All; Date Range: 01/01/2020 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: July 19, 2021.
[20] *Id.*
[21] Witness Moul's Rebuttal Testimony, page 13: line 10.

reasoning for why he believed that CPA' cost of equity had risen.[22] As I have noted previously, the DJUA has rebounded from its low in March 2020 brought on by the COVID-19 pandemic. Additionally, interest rates have remained at low levels for a sustained period of time. Simply pointing to a higher VIX as justification for a higher cost of equity for CPA is erroneous and misleading.

Mr. Moul's recommended 10.95% ROE was overstated when the Company filed its 2020 base rate case on April 24, 2020 and, again, when it filed the current case on March 30, 2021. Mr. Moul's recommendation would allow CPA to over-earn, at the expense of captive consumers in Pennsylvania, in a marketplace that is reflective of much lower capital costs. In my over three decades of experience in this industry, I have never seen any research that implies VIX drives market returns more so than interest rates or even basic risk/return variables. Simply put, Mr. Moul's statement as noted above is a far stretch for an unjustifiably high ROE.

If the Commission follows Mr. Moul's logic regarding the VIX and the allowed ROE, it must then turn a blind eye to interest rate levels and all of the other variables that impact the risk and return of CPA in this case. In addition, if one were to follow the logic being suggested by Mr. Moul in this instance, it would necessitate that companies should receive significantly lower allowed ROEs in years when the VIX is lower. If that is the case, then Mr. Moul should have recommended a lower ROE in the 2021 CPA rate case than he did in the 2020 CPA rate case given that the 2021 YTD Average VIX is lower than the 2020 Average VIX.

[22] Witness Moul's Rebuttal Testimony, page 13: lines 14 - 16.

Q. MR. O'DONNELL, WHAT IS A "REGULATORY PREMIUM"[23] AS NOTED BY MR. MOUL IN HIS TESTIMONY?

A. A regulatory premium is defined as the difference between an allowed return on equity ("ROE") and interest rates. An example would be the difference between an allowed ROE of 8.75% and the prevailing interest rate of a 30-year US Treasury bond of 1.50%. In this example, the regulatory premium would be 7.25% (*i.e.*, 8.75% less 1.50%).

Q. DO YOU AGREE WITH MR. MOUL'S CLAIM THAT ALTHOUGH REGULATED ROE'S HAVE TRENDED DOWNWARD,[24] REGULATORY PREMIUMS HAVE INCREASED?

A. Yes. However, Mr. Moul fails to provide the necessary context to support his argument. While I agree the regulatory premiums have risen, I do not believe the increase in the regulatory premium has offset the lower cost of capital for regulated utilities.

Utility regulators across the country tend to move more slowly in regard to changes in allowed ROEs. As such, it is not surprising that allowed ROEs have not fallen at the same pace as interest rates. The net result of the slow fall of allowed ROEs, as compared to the more rapid change in the decreasing interest rates over time, has led to an increase in the "regulatory premium" as noted by Mr. Moul. The situation as indicated by Mr. Moul is simply a function of regulators being concerned with making changes to allowed ROEs at a pace similar to that of the abrupt changes seen within interest rates. Such an observation is inherent in regulation. It does not, however, negate the fact that the cost of capital in today's market is lower than it was at the time of the Company's previous rate filings, as

[23] Witness Moul's Rebuttal Testimony, page 14: line 15.
[24] Witness Moul's Rebuttal Testimony, page. 14: line 19 – 20.

evidenced by the decrease in interest rates and the bounce back / increase in the utility equities market. One simply cannot deny the strong increase in the stock market and the environment of lower interest rates has resulted in a lower cost of capital environment for utilities.

I further add that the 4.89% to 5.81% premium that Mr. Moul cites on page 15 of his testimony is consistent with the 4.25% to 6.25% risk premium that I found appropriate for use in the Capital Asset Pricing Model ("CAPM").

IV. MR. MOUL'S PROPOSED ADOPTION OF AN ROE FLOOR

Q. WHAT IS A DISTRIBUTION SYSTEM IMPROVEMENT CHARGE ("DSIC")?

A. The DSIC allows CPA to employ a surcharge on ratepayers to recover certain eligible investments in gas distribution system replacements between base rate cases. As such, the DSIC amounts to an automatic rate recovery mechanism for CPA that, in turn, lowers its risk.

Consumers are protected by a 5% cap on the amount of eligible investment in plant which CPA may recover through the DSIC surcharge. If the Commission established an allowed ROE for the utility in a base rate case within two years prior, that ROE is used as an earnings cap for DSIC purposes. Otherwise, the Commission's Quarterly Earnings Report identifies a ROE which is used as the upper limit on the return that the utility may earn on the plant investments recovered through its DSIC.

Q. DO YOU AGREE WITH MR. MOUL'S POSITION THAT THE COMMISSION'S CURRENT 10.20% ROE FOR DSIC PURPOSES SHOULD SERVE AS THE FLOOR FOR THE COMMISSION'S ROE DETERMINATION IN THIS BASE RATE CASE?[25]

A. No, I do not. Mr. Moul's inference that all DSIC-eligible plant investment incurred between base rate cases is recovered, including a ROE at the level reported in the Commission's Quarterly Earnings Report, is incorrect.

First, CPA may only recover through the CPA DSIC a surcharge of up to 5% of CPA's investment in DSIC-eligible plant investment. When CPA's DSIC investment is in

[25] Witness Moul's Rebuttal Testimony: page 11: line 18 – page 12: line 8.

excess of 5%, the amount of plant in excess of 5% is not recoverable through the DSIC surcharge. CPA's investment in DSIC-eligible plant in excess of the 5% cap is recognized for rate-setting in the Company's next base rate case, just like other CPA additions to rate base which are not DSIC-eligible.

Second, Pennsylvania law and regulations allow CPA to implement a DSIC surcharge to further public policy which favors investment in main replacements, subject to consumer protections. CPA's calculated achieved return on its DSIC investment is compared to one of two benchmarks. The first benchmark is the utility's allowed ROE in a base rate case within two years. For CPA, that is the 9.86% ROE allowed by Commission order in February 2021. In the absence of a specific allowed ROE, the Commission's Quarterly Earnings Report identifies an industry ROE. The benchmark ROE serves as a guard against over-earnings. If CPA's calculated achieved return on its DSIC investment exceeds the applicable benchmark ROE, then CPA cannot collect the DSIC surcharge for the next quarter.

I recommend that the Commission reject Mr. Moul's proposed floor. An ROE that is calculated in some way by Commission staff, for use in a single quarter test of whether a gas utility without a recent allowed cost of equity may be over-earning through its DSIC surcharge, is not suited to identification of the cost of common equity which CPA should be allowed the opportunity to earn as of the end of the FPFTY.

V. MR. MOUL'S DISCUSSION OF THE PROXY GROUP UTILIZED IN MY DIRECT TESTIMONY

Q. DOES YOUR SEPARATE ANALYSIS OF A COST OF EQUITY FOR CPA'S PARENT NISOURCE PROVIDE USEFUL INFORMATION?

A. Yes. As referenced in my direct testimony, due to the outcomes of the Hope and Bluefield cases, commissions across the country use proxy groups to set the return on equity in regulated rate cases. As such, I conducted a cost of equity analysis based upon a comparable company proxy group comprised of natural gas utilities, but I also conducted a separate analysis of NiSource.

Mr. Moul claimed that I did not provide any valid reason to examine NiSource separately in this case.[26] I disagree. The data produced by the analysis performed specifically on NiSource provides a direct link between NiSource and CPA. Indeed, one cannot buy stock in CPA directly, but must instead purchase stock in NiSource. Hence, it is critical in the analysis of CPA that one also examine the financial details of NiSource, its parent holding company, given the direct link between the two. Credit rating agencies have recognized this undeniable bond between a parent holding company and its utility subsidiary and closely tie the corresponding credit ratings of the two entities. Hence, it is naïve to think the equity cost of capital for NiSource is not determinative as to the equity cost of capital for CPA.

To avoid the problem of circularity, I have also examined the cost of capital results of gas utilities that operate in a similar environment to CPA. In doing so, I have provided the Commission with a well-rounded examination of several different proxy companies for

[26] Witness Moul's Rebuttal Testimony, page 16: lines 17-25.

CPA. Such a holistic analysis is far better than picking and choosing companies that may or may not provide information as to the proper cost of capital for a utility.

Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. MOUL'S CRITICISM OF YOUR PROXY GROUP?

A. Yes. Within my direct testimony, I explained that I opted to use the full group of ten gas utilities compiled and followed by *Value Line* due to the fact that the number of available gas utilities followed by financial agencies has been dwindling in recent years.[27] In contrast, Mr. Moul argued within his direct testimony that UGI Corporation should be removed from the *Value Line* industry grouping because its operations are more diversified outside of the gas distribution business in contrast to the other companies in the group.[28] I pointed out within my direct that Chesapeake Utilities also operates a diverse set of businesses and that as such, I did not find it appropriate to include one diverse company.

Additionally, I am aware UGI Corp. announced on December 30, 2020 their plan to purchase Mountaineer Gas in West Virginia.[29] As of July 21, 2021, the deal has not closed. Normally, I would not include a company in my proxy group that is in the middle of an acquisition. However, in this case, I chose to include UGI for the following two reasons: 1. Mountaineer Gas is quite small relative to UGI (about 6% in total assets); and 2. the natural gas proxy group is already small so eliminating a company may allow another entity to skew the results of the group.

[27] Witness O'Donnell's Direct Testimony: page 85: line 19 - page 86: line 4.
[28] Witness Moul's Direct Testimony, page 16: line 16 - page 17: line 6.
[29] UGI Corp. Press Release, "UGI to Aquire Mountaineer Gas" (Dec. 30, 2020). See, https://www.businesswire.com/news/home/20201230005344/en/UGI-to-Acquire-Mountaineer-Gas-Company.

Q. WHAT DO THESE ISSUES WITH MR. MOUL'S PROXY GROUP PROCESS MEAN WITHIN THE CONTEXT OF THIS RATE CASE?

A. In an industry where there are a higher number of such comparable companies, I have historically taken a deeper look into which companies I believe are more appropriate than others to be included within my proxy group. However, the number of companies within the natural gas industry is dwindling due to a variety of factors that I explained within my direct. As such, given that none of the ten companies within the Natural Gas industry grouping provided by *Value Line* were undergoing any sort of bankruptcy, legal issues, restructuring, or merger activities at the time when my direct testimony was filed, I utilized the full ten companies provided by *Value Line* as opposed to examining metrics of whose importance is inherently subjective to the analyst performing the cost of capital analysis. Mr. Moul, however, chose to use various financial metrics as a basis for developing his proxy group, the underlying data of which included numerous issues.

I ultimately believe that a large part of what this proxy group process provides, especially in an industry where the number of comparable companies is already so small, is simply a look into how an analyst attempts to shape their comparable company proxy group to fit the ROE narrative for their respective client. Put simply, by including such voluminous discussion of the composition of one's proxy group, Mr. Moul is distracting from the key point in this case that his 10.95% ROE recommendation is grossly in excess of any such benchmark or comparable measure and is inflated by his choices of certain forecasted data and his various unwarranted upward adjustments.

VI. <u>MR. MOUL'S CRITICISM OF MY DCF CALCULATION INPUTS AND ASSOCIATED RESULTS</u>

Q. IS MR. MOUL'S CRITICISM OF YOUR DCF GROWTH RATES VALID?

A. No. In my direct testimony and associated exhibits, I included EPS, DPS, and BPS growth rates from historical and forecasted perspectives, as well as plowback (*i.e.*, percent retained to common equity) growth rates. Mr. Moul responded to my use of these metrics in his rebuttal testimony by stating:

> Mr. O'Donnell presents DPS (dividends per share) and BPS (book value per share) growth rates in addition to EPS (earnings per share) growth. Mr. O'Donnell is incorrect to believe that DPS and BPS have any role in the DCF Model.[30]

Mr. Moul also faults my use of plowback (*i.e.*, percent retained to common equity) growth rates.[31] I disagree with the arguments presented by Mr. Moul and note that there are various academic articles and journals that specifically call into question the accuracy of earnings predictions and forecasts. For example, as noted within my direct testimony, in November 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "*Analysts' Conflict of Interest and Biases in Earnings Forecasts*" in the *Journal of Finance*. The conclusion of the paper stated:

> . . . it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is <u>little forecastability in earnings, and analysts' estimates tend to be overly optimistic</u>.[32]

[30] Witness Moul's Rebuttal Testimony, page 21: lines 9 – 11.
[31] Witness Moul's Rebuttal Testimony, page 22: line 7 - page 23: line 6.
[32] K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* (2003), page 683. (underline emphasis added).

By relying entirely on EPS growth rates, and specifically only relying on those provided from a forecasted perspective as Mr. Moul has done in his analysis, he has not considered all of the available data and has taken an unnecessarily narrow viewpoint. Please note that within my DCF analysis, I have also clearly evaluated certain forecasted EPS growth rates. However, I believe that relying entirely upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely.

Q. DO YOU AGREE WITH MR. MOUL'S DISCUSSION REGARDING HIS SOLE USE OF FORECASTED GROWTH RATES FOR APPLICATION WITHIN THE DCF?

A. No, I do not. Mr. Moul criticized my use of historical growth rates by stating the following within his rebuttal:

> …forecast earnings growth is the only valid measure of growth for DCF purposes.[33]

As I stated in direct testimony, investors examine a wide variety of growth rate metrics to inform their investment decisions. One of my main purposes when presenting testimony to a Commission is to provide an analysis that is as complete and as thoroughly researched as possible. Presenting such a thorough analysis includes the presentation of EPS, DPS, and BPS growth rates from a historical and forecasted perspective as well as the presentation of other growth rates, such as plowback. The data included within an analyst's testimony should speak for itself without the analyst feeling the need to make various modifications or adjustments to the data that would ordinarily constitute the final results.

[33] Witness Moul's Direct Testimony, page 23: lines: 14-15.

Q. MR. MOUL CLAIMED THAT YOU DID NOT REFUTE HIS PROPOSED 217-BASIS POINT LEVERAGE ADJUSTMENT AND THAT THE ADJUSTMENT SHOULD BE ACCEPTED. IS THIS CORRECT?

A. No, this is not correct. In his rebuttal testimony, Mr. Moul included the following:

> The I&E and OCA witnesses have not refuted the accuracy of the Company's leverage adjustments to the DCF and beta component of the CAPM. Without such opposition, these should be accepted.[34]

In including the above statement within his rebuttal testimony, Mr. Moul has not acknowledged the section of my direct testimony which stated the following:

> **Q. DO YOU AGREE WITH MR. MOUL'S USAGE OF THE 217-BASIS POINT LEVERAGE ADJUSTMENT.**
>
> A. No. This adjustment stems from Mr. Moul's apparent belief that investors are unaware of debt on the Company's books and, therefore, they must be compensated for the additional risk.[35]

Within pages 97-99 following the above Q&A from my direct testimony, I outlined in detail why I do not agree conceptually with the principles behind Mr. Moul's leverage adjustment and why I believe that this leverage adjustment is simply an attempt to justify an unreasonable return on equity for the Company.

The inclusion of such a leverage adjustment by Mr. Moul stems from his belief that investors, when purchasing an equity, are unaware that the market price of a security is different than the book value of the underlying security. Such a belief is simply irrational. Mr. Moul's market-to-book leverage adjustment of 217- basis points is another attempt to justify a higher allowed ROE than what is currently being found in the marketplace.

I also again call attention to Mr. Moul's response to two separate data requests in which Mr. Moul noted that he had proposed a leverage adjustment within his DCF model

[34] Witness Moul's Rebuttal Testimony, page 3: lines 1 – 3.
[35] Witness O'Donnell's Direct Testimony, page 98: lines 1 – 8.

in over thirty different rate cases on behalf of a Pennsylvania public utility in the past ten years,[36] and that Mr. Moul was not aware of any such cases within the past ten years in which the Commission approved one of these leverage adjustments. Mr. Moul has not provided sound reasoning as to why the Commission should adopt this leverage adjustment in determining an appropriate cost of equity for CPA and the Company's ratepayers in this proceeding.

[36] Witness Moul's response to Question No. **OCA-III-16** and Question No. **OCA-III-17.**

VII. MR. MOUL'S CRITICISM OF MY CAPM CALCULATION INPUTS AND ASSOCIATED RESULTS

Q. MR. MOUL CRITICIZED YOUR CAPM MODEL FOR NOT INCLUDING FORWARD-LOOKING DATA SPECIFIC TO THE RISK-FREE RATE OF RETURN. DO YOU HAVE A RESPONSE TO THIS CLAIM?

A. Yes. Within his rebuttal testimony, Mr. Moul makes the assertion that:

> Mr. O'Donnell's CAPM approach suffers from the infirmity of not positioning the risk-free rate of return in a forward-looking manner – rather he used historical results obtained from the past year.[37]

Within my direct testimony and related exhibits, I noted that I developed my CAPM results of 6.0% – 8.0%[38] based partially upon my use of the maximum, average, and minimum values of the 30-year U.S. Treasury Bond Yields from April 24, 2020 through June 11, 2021 to approximate the risk-free rate. The average value for this period was 1.74%.[39]

Given that the risk-free rate used by Mr. Moul in his direct testimony was 2.0%[40], there is not a drastic difference in the risk-free rates used in my CAPM analysis in comparison to what was used by Mr. Moul in his direct.

Additionally, in a different natural gas utility base rate case in January 2019, Mr. Moul claimed that the forecasted risk-free rate for use within the CAPM was appropriate to be set at 3.75%.[41] For context, at the start of 2019, the 30-year US Treasury Bond yield was 2.97%, decreased to 2.39% as of the end of 2019 (*i.e.,* prior to the impacts of the

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[37] Witness Moul's Rebuttal Testimony, page 30: lines 16 – 195.
[38] Witness O'Donnell's Direct Testimony, Table 9, page 83.
[39] Witness O'Donnell's Direct Testimony, page 82, line 8.
[40] Witness Moul's Direct Testimony, page 31, lines 1 – 2.
[41] Pa. P.U.C. v. UGI Utilities – Gas Div., Docket No. R-2018-3006814, Company Rate Filing, Book IV, UGI Gas St. 5, Paul R. Moul Direct Testimony, page 46.

COVID-19 pandemic), and then decreased to 1.79% as of January 27, 2021.[42] Mr. Moul's own previous forecasts and overreliance upon positioning the "risk-free rate of return in a forward-looking manner," have simply missed the mark badly even prior to the impacts of the COVID-19 pandemic.

Q. MR. MOUL CRITICIZED YOUR USE OF THE GEOMETRIC MEAN IN EVALUATING HISTORICAL RETURNS DATA. HAVE YOU ONLY RELIED UPON THE GEOMETRIC MEAN IN ANALYZING SUCH RETURNS?

A. No. Mr. Moul included the following passage within his rebuttal testimony:

> Mr. O'Donnell has incorrectly used the geometric mean in his historic analysis of the total market returns.[43]

However, within **Table 8** included on page 78 of my direct testimony, I very clearly included both the geometric and arithmetic mean returns as provided by the Ibbotson SBBI Annual Yearbook for the purpose of the comparison of these returns to the forecasted market return and resulting risk premium used by Mr. Moul. Nowhere within my direct testimony did I say that I singularly relied upon the geometric mean instead of the arithmetic mean, nor that I afforded the arithmetic mean no weight in my analysis.

I presented both the geometric average return and the arithmetic average return within my direct testimony in order to provide the Commission as much information as possible. As can be seen in Table 8 of my prefiled direct testimony, I calculated the arithmetic mean equity risk premium to be 3.4%. I considered this arithmetic risk premium along with several other factors and derived an equity risk premium of 4.25% to 6.25% and

[42] U.S. Treasury, Daily Treasury Yield Curve Rates, https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield (last accessed on July 27, 2021).
[43] Witness Moul's Rebuttal Testimony, page 31: lines 1-2.

a corresponding CAPM range of 6.0% to 8.0%. Mr. Moul's comments on my reliance upon the geometric mean versus the arithmetic mean misrepresents my testimony.

Q. MR. MOUL CRITICIZED YOUR USE OF CERTAIN FORECASTED MARKET RETURNS.[44] WHAT DO THESE MARKET RETURN PROJECTIONS SHOW AND WHY DO YOU FEEL THEY ARE MORE APPROPRIATE THAN THE FORECASTED MARKET RETURNS USED BY MR. MOUL?

A. On Pages 78 - 81 of my direct testimony in this case, I presented various forecasted market returns from a multitude of sources that ultimately led to my projected equity risk premium of 4.25% - 6.25%[45], which when taken in conjunction with my 30-year risk free rate range of 1.17% to 2.45%[46] provide my forecasted overall market return range.

In response to these forecasted market return expectations that indicate that future return expectations for U.S. equities will be lower than what they have been historically, Mr. Moul claims that the sources I provided on Pages 78 – 80 of my direct testimony were "*non-standard sources*."[47] My sources are certainly not "non-standard sources" as contended by Mr. Moul. *Vanguard* is the second largest mutual fund industry in the country and *Schwab* is the third largest. Mr. Moul may not like the forecasts provided by the financial institutions I cited (inclusive of *Vanguard*, *Schwab*, and *Morningstar*) as such forecasts would indicate lower market return forecasts than those claimed by Mr. Moul, but the sources are all highly regarded mainstream financial service providers and are in no way "non-standard".

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[45] Witness O'Donnell's Direct Testimony, page 81: line 18.
[46] *Id.*, page 82: line 13.
[47] Witness Moul's Rebuttal Testimony, page 32: line 21.

Q. HOW DO MR. MOUL'S SOURCES TO DEVELOP HIS MARKET RETURN FORECASTS COMPARE TO THOSE WHICH YOU USED?

A. In reference to the sources used by Mr. Moul for the forecasted market premiums within his CAPM analysis, note that in my direct testimony I criticized Mr. Moul's use of a "Median Appreciation Potential" as part of his Forecasted "Value Line Return", which was one of the two data points he used to develop his Forecasted Market Return.[48] This Median Appreciation Potential value approximates the overall market's 3- to 5-year appreciation price potential. However, this price appreciation potential varies widely, especially when an anomalous event such as the COVID-19 pandemic occurs. For example, the 3- to 5-year price appreciation potential was <u>65%</u> "26 weeks" prior to December 25, 2020; was <u>145%</u> during the "Market Low" period on March 23, 2020; and was <u>30%</u> during the "Market High" period on December 8, 2020.[49] These values clearly vary wildly from the <u>35%</u> 3- to 5-year Median Appreciation Potential used by Mr. Moul within his CAPM analysis in this proceeding that ultimately provided him with his 7.79% calculated *Value Line* Forecasted Market Premium and *Value Line* Forecasted Market Return of 9.79%.

These wide swings in the Median Appreciation Potential can be seen in **Table 11** of my direct testimony that shows Mr. Moul's *Value Line* Forecasted Market Return has varied from a low of 7.64% in 2018 to a high of 15.74% in 2020.

The issues cited above with Mr. Moul's *Value Line* Forecasted Market Return follow through to the other data point used by Mr. Moul to develop his Overall Forecasted Market Return given the inputs used by Mr. Moul to calculate his *S&P 500* Forecasted

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[49] Witness Moul's Response to Question No. **OCA-IX-1**, **Attachment A**.

Market Return values. The wild fluctuation in the growth rate driving this data point can be seen in **Table 12** to my direct testimony. As shown therein, Mr. Moul's *S&P 500* Forecasted Market Return has varied from a low of 6.07% in 2020 to a high of 11.21% in 2021. Such wide variations in the returns shows that such an analysis is simply not reliable on a long-term basis.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE MARKET RETURN FORECASTS USED BY MR. MOUL?

A. Yes. As noted within my direct testimony, I included reference to NiSource's (*i.e.*, CPA's parent company) own pension plan estimates. In response to data request **OCA-III-11**, NiSource noted that they have assumed an 8.25% US Large Cap Equity assumed market return and an 8.75% US Small Cap Equity assumed market return.[50] These values are clearly far below Mr. Moul's overall Forecasted Market Return.

Mr. Moul himself provided the data request response to **OCA-III-11** and opted not to address this criticism of his growth rates within his rebuttal testimony. Ultimately, Mr. Moul's chosen overall Forecasted Market Return is simply illogical and directly conflicts with his employer's own pension forecast, upon which the pension revenue requirement in this case is calculated.

For the reasons outlined above, the Forecasted Market Return and related Forecasted Market Premium used by Mr. Moul should be given no weight in this proceeding. The proper Forecasted Market Premium for application within the CAPM more closely approximates 4.25% – 6.25% as I have explained in my direct testimony.

[50] Witness Moul's response to Question No. **OCA-III-11**.

Q. IN HIS REBUTTAL TESTIMONY, MR. MOUL STATED THAT THE ADJUSTMENTS HE MADE TO HIS CAPM MODEL WERE APPROPRIATE. DO YOU HAVE A RESPONSE TO THIS SPECIFIC CLAIM?

A. Yes. I still oppose Mr. Moul's leverage and size adjustments used within his CAPM analysis. As I noted above in response to Mr. Moul's similar claim for his leverage adjustment within his DCF, the adjustments Mr. Moul employed in his CAPM only serve as a measure to artificially inflate his ROE recommendation.

I explained in detail within my direct testimony my reasoning for my disagreement with Mr. Moul's unleveraging and releveraging of the Betas used in the CAPM and Mr. Moul's CAPM 102-basis point firm size adjustment.

Furthermore, I want to again call attention to Mr. Moul's response to two separate data requests wherein Mr. Moul noted that he had proposed a firm size adjustment within his CAPM models in over thirty different rate cases on behalf of a Pennsylvania public utility in the past ten years,[51] and that Mr. Moul was not aware of any case within the past ten years in which the Commission had approved his proposed firm size adjustment to a CAPM analysis.[52]

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

[51] Witness Moul's response to Question No. **OCA-III-16**.
[52] Witness Moul's response to Question No. **OCA-III-17**.

Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	45.74%	4.58%	2.09%
Short-Term Debt	4.26%	0.85%	0.04%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.63%**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Kevin W. O'Donnell, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 2-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 27, 2021
*314208

Signature: Kevin W. O'Donnell

Consultant Address: Nova Energy Consultants, Inc.
1350 SE Maynard Road
Suite 101
Cary, NC 27511

OCA Statement No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	: : :	
v.	:	Docket No. R-2021-3024296
COLUMBIA GAS OF PENNSYLVANIA, INC.	: : :	

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 16, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFGD") as a Management Trainee in the Research and Statistical Services ("RSS") Department. I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply's") rate department where my responsibilities included utility cost-of-service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Federal Energy Regulatory Commission ("FERC") Purchased Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD's 1307(f) proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1996, I became a Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost-of-service and rate design analyses, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and evaluation of customer choice natural gas transportation programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON UTILITY RATES IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony on nearly 400 occasions in proceedings before the FERC and utility regulatory commissions in Arkansas, Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, Ohio, Rhode Island, South Carolina, Texas, Utah, and Virginia, as well as before the Pennsylvania Public Utility Commission ("Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On March 30, 2021, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company") filed an application with the Commission to increase its distribution base rates by $98.3 million, or 19.7 percent. Exeter was retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the allocated cost-of-service ("ACOS") studies and rate design proposals included in Columbia's application, as well as the Company's proposal to adopt a Revenue Normalization Adjustment ("Rider RNA") and a Federal Tax Reform Adjustment ("FTRA"). My testimony addresses Columbia's ACOS studies and proposed rate design, as well Rider RNA and the FTRA.

Q. ARE THERE ADDITIONAL CONSIDERATIONS IN THIS PROCEEDING THAT ARE NOT OFTEN SEEN IN A TRADITIONAL BASE RATE CASE?

A. Yes. As explained in the Direct Testimony of Mr. Roger Colton in OCA Statement No. 4, Pennsylvania and the rest of the world has faced significant hardships due to the COVID-19 pandemic. The impact of the COVID-19 pandemic continues to adversely affect Pennsylvania residents. The Commission should consider the impacts of the pandemic when reaching its decision as to the extent of the increase that should be authorized for Columbia in this proceeding. Authorizing a rate increase in this proceeding when unemployment numbers are close to record-highs would further increase the hardships caused by the COVID-19 pandemic. Moreover, the economic effects of the pandemic will not be fully known for some time. The Commission should carefully consider and weigh these important consumer interests when evaluating the Company's claims for a rate increase. Counsel for the OCA will further address Columbia's request for rate relief in its briefs.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. If the Commission determines that the traditional base rate setting process should be followed in this proceeding, wherein rates are based on cost of service and other generally accepted rate design principles, I have reached the following conclusions:

- Typical of a natural gas distribution company ("NGDC"), a significant percentage of Columbia's plant, 65 percent, is comprised of distribution mains.

- Columbia is sponsoring ACOS Studies in its application using two different methodologies, each at present and proposed rates. Under one method, distribution mains investment is allocated partially based on the number of customers and partially based on design day demands ("Customer-Demand Study"). Under the second method, distribution mains investment is allocated utilizing the Peak and Average method ("Peak & Average Study"). Columbia's application also includes a third ACOS study that reflects an average of the Customer-Demand and Peak & Average ACOS Studies ("Average Study"). Columbia claims that it has relied on the Peak & Average Study to support its proposed revenue distribution among its various customer classes in this proceeding.

- Columbia's reliance on the Peak & Average Study as the basis of its proposed revenue distribution is consistent with Commission precedent and the Commission's decision in the Company's most recent base rate proceeding (Docket No. R-2020-3018835). It is also consistent with cost of service principles. However, the revenue distribution presented by Columbia does not reflect adequate movement toward cost-based rates for each customer class, and does not adequately account for the significant subsidies provided to certain customers that receive service at less than cost of service rates.

- The OCA's proposed revenue distribution in this proceeding, which is also based on the Company's Peak & Average Study, provides for reasonable movement toward cost-based rates and adequately accounts for the subsidies provided to certain customers and, therefore, should be accepted by the Commission in this proceeding.

- Columbia's proposed Residential customer charge is unreasonable and should be rejected.

Irrespective of what the Commission decides in this proceeding with respect to the base rate increase, and the allocation of that increase to the various customer classes served by Columbia, I recommend that:

- Prior to entering into a new contract or extending an existing contract for a Flex rate customer, Columbia should continue its practice of updating the Competitive Alternative Analysis to verify that the customer should continue to receive service at discounted rates. Each updated Competitive Alternative Analysis should be presented by the Company in its next base rate proceeding.

- The Company's Flex rate customers receive a significant cost of service subsidy from customers paying Columbia's tariff rates. Therefore, each Competitive Alternative Analysis presented in the Company's next base rate case should also evaluate whether the revenues provided by each Flex rate customer exceeds the long-term marginal cost of service. Rates charged to Flex rate customers should be sufficient to recover the long-term marginal cost of service.

- Proposed Rider RNA should be rejected.

- The proposed FTRA should be rejected.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Including this introductory section, my testimony is divided into six sections. In the following section, I describe the ACOS Studies presented by Columbia in this proceeding and explain why the Company's Peak & Average Study should be used to determine the distribution of the revenue increase authorized by the Commission in this proceeding. The next section addresses class revenue requirement allocations and Flex customers rate discounts. The fourth section of my testimony addresses Columbia's proposed Residential rate design. The fifth section of my testimony addresses Columbia's proposed Rider RNA. The final section of my testimony addresses the FTRA.

II. COST ALLOCATION

Q. BRIEFLY DESCRIBE THE COST-OF-SERVICE STUDIES SUBMITTED BY COLUMBIA IN THIS PROCEEDING.

A. Columbia submitted average embedded ACOS Studies employing two different cost allocation methodologies. These cost allocation methods differ in the approach used to allocate distribution mains investment. The Company's ACOS Studies are sponsored by Mr. Chad Notestone (Columbia Statement No. 11).

Q. PLEASE IDENTIFY THE CUSTOMER RATE CLASSES INCLUDED IN THE COMPANY'S ACOS STUDIES.

A. The Company's ACOS Studies include seven rate classes:

- Residential Sales Service and Residential Distribution Service ("RSS/RDS");
- Low-Volume Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service ("SGSS1/SCD1/SGDS1");
- High-Volume Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service ("SGSS2/SCD2/SGDS2");

- Small Distribution Service and low-volume, Large General Sales Service ("SDS/LGSS");
- Large Distribution Service and high-volume, Large General Sales Service ("LDS/LGSS");
- Main Line Distribution Service ("MLDS"); and
- Flexible Rate Provisions and Negotiated Contract Service ("Flex").

Q. HOW DO THE ACOS STUDIES PREPARED BY COLUMBIA DIFFER?

A. In Columbia's ACOS Studies, the Company first identified and directly assigned the actual investment inventory of distribution mains for the MLDS rate class. The distribution mains investment not assigned to the MLDS rate class was allocated to the remaining rate classes. Columbia then prepared ACOS Studies utilizing two different methods to allocate the non-MLDS distribution mains investment to the other rate class. Both methods were used to prepare ACOS Studies at present and proposed rates.

Under the first method, which I will refer to as the Customer-Demand method, distribution mains investment was allocated to rate class partially based on the number of customers and partially based on the design peak day demands of the customers in each rate class. Under the second method, which I will refer to as the Peak & Average method, the remaining distribution mains investment was allocated 50 percent based on the design peak day demands and 50 percent based on annual, or average daily, demands of the customers in each rate class. In addition to the ACOS Studies prepared using these two methods, the Company prepared an Average ACOS which reflects an average of the Customer-Demand and Peak & Average ACOS Studies.

Q. WHICH ACOS STUDY DID THE COMPANY UTILIZE AS THE PRIMARY GUIDE FOR THE DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. Columbia claimed it used the Peak & Average Study as the ACOS study to establish rates in this proceeding. The Peak & Average Study was given primary consideration because of the Commission's decision in the Company's 2020 rate case (Docket No. R-2020-3018835) which approved the use of the Peak & Average method. In the Opinion and Order issued in that proceeding on February 19, 2021, the Commission found:

> Based on our review of the record, and as noted by the ALJ, we have consistently used the Peak & Average methodology for the allocation costs for NGDCs. In this regard, we find that the Customer-Demand method and the Average ACCOSS, which depends on the Customer-Demand methodology, would be inconsistent with Commission precedent and generally accepted principles for NGDCs because they both contain customer cost components.
>
> We are persuaded by the arguments presented by the OCA's witness, Mr. Mierzwa, on pages 6-7 of the OCA's Statement No. 4, and in the OCA's Main Brief on pages 139-145, which we adopt herein, by reference, where he describes the faults of adopting the Customer-Demand ACCOSS. In the OCA's Statement No. 4, Mr. Mierzwa explained that under the Customer-Demand method, "the distribution mains investment assigned to each category is allocated to rate class **partially based on the number of customers** and partially based on the design day demands of the customers in each rate class that are served by each of the categories of distribution mains …." OCA St. 4 at 6-7 (emphasis added). In the OCA's Main Brief, Mr. Mierzwa pointed out that the Customer-Demand ACCOSS uses "a minimum system approach where the entire distribution mains system is hypothetically comprised of only 2-inch pipe." Mr. Mierzwa continued that, "[t]he goal of such a study is to attempt to assign costs based on merely connecting customers to the system, as opposed to supplying gas to customers – which is how the distribution system actually works on a day-to-day basis." OCA M.B. at 140. (Order at 215).

> In light of the above, we remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment because it is the load that determines the main investment, not the number of customers served. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served.
>
> Furthermore, distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand ACCOSS. The basic reason Columbia invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design peak demands in excess of annual demands. (Order at 217).
>
> For all these reasons, we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment. Accordingly, we shall deny Columbia's Exceptions Nos. 18 and 19, and the OSBA's Exception No. 1, and PSU's Exception No. 1 as they relate to their respective ACCOSS arguments and adopt the OCA's P&A ACCOSS as proffered by OCA Witness Mr. Mierzwa in OCA Statement No. 4, at 5-33, and the OCA's Main Brief, at 150-155. (Order at 218).

Q. PLEASE SUMMARIZE THE RESULTS OF COLUMBIA'S PEAK & AVERAGE ACOS.

A. Table 1 shows the results of Columbia's Peak & Average Study at present rates.

Table 1.
Class Rates of Return
Columbia Peak & Average ACOS Study
Results at Present Rates

Class	Rate of Return	Index
RSS/RDS	6.541%	1.26
SGSS1/SCD1/SGDS1	5.579	1.08
SGSS2/SCD2/SGDS2	5.929	1.14
SDS/LGSS	4.910	0.95
LDS/LGSS	0.905	0.17
MLDS	157.568	30.41
FLEX	(4.372)	(0.84)
Overall:	**5.181%**	**1.00**

Q. SHOULD THE COMPANY'S PEAK & AVERAGE ACOS STUDY BE UTILIZED TO DETERMINE THE DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED IN THIS PROCEEDING?

A. Yes.

III. CLASS REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE HOW COLUMBIA IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.

A. Columbia claims that it generally sought to allocate the revenue increase toward the cost of service indicated by the results of its Peak & Average Study. The Company's proposed base rate revenue distribution is presented in Table 2. The relative rates of return ("ROR") at present and proposed rates are also identified in Table 2. An ROR of less than 1.0 indicates that a customer class is providing revenues that are less than that class' indicated cost of service, a ROR 1.0 indicates that a customer class is providing revenues that are equal to that class' indicated cost of service, and a ROR greater than 1.0 indicates that a customer class is providing revenues that are greater than that class' indicated cost of service.

Table 2.
Columbia Proposed Revenue Distribution

Class	Present Rates	Proposed Rates	Increase	Percent	Relative Rate of Return: Present Rates	Relative Rate of Return: Proposed Rates
RSS/RDS	$363,896,616	$431,660,243	$67,763,627	18.6%	1.26	1.22
SGSS1/SCD1/SGDS1	40,420,998	48,885,408	8,464,410	20.9%	1.08	1.06
SGSS2/SCD2/SGDS2	44,580,611	53,711,911	9,131,300	20.5%	1.14	1.08
SDS/LGSS	26,687,078	33,694,442	7,007,364	26.3%	0.95	1.00
LDS/LGSS	19,742,916	25,638,165	5,895,249	29.9%	0.17	0.38
MLDS	1,111,444	1,111,823	379	0.0%	30.41	20.00
FLEX	3,398,752	3,414,542	15,790	0.5%	(0.84)	(0.55)
Total:	**$499,838,415**	**$598,116,534**	**$98,278,118**	**19.7%**	**1.00**	**1.00**

Q. WHAT ARE SOME OF THE PRINCIPLES OF A SOUND REVENUE ALLOCATION?

A. A sound revenue allocation should:

- Utilize class cost-of-service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to ratepayers or the utility (gradualism);
- Yield the total revenue requirement;
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability, and feasibility of application; and reflect fairness in the apportionment of the total cost of service among the various customer classes.[1]

Q. IS COLUMBIA'S PROPOSED REVENUE ALLOCATION REASONABLE?

[1] *Principles of Public Utility Rates*, Second Edition, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen; Public Utility Reports, Inc., 1988, pages 383-384.

A. No. Although Columbia's proposed revenue allocation may be based on the results of the Company's Peak & Average Study, it does not reflect adequate movement toward cost-based rates for each customer class, and does not adequately account for the significant subsidies provided to LDS/LGSS and Flex rate customers that receive service at less than cost of service rates.

Q. PLEASE IDENTIFY THE SUBSIDY CURRENTLY PROVIDED TO LDS/LGSS AND FLEX RATE CUSTOMERS.

A. As indicated in Table 1, LDS/LGSS customers currently provide a rate of return of 0.17 percent at present rates. To provide revenues equal to the cost of service indicated by the Company's Peak & Average Study at proposed rates, LDS/LGSS customer revenue would need to be increased from the current level of $19,742,916 (Table 2) to approximately $39,500,000. As such, at present rates, other customers would be providing a subsidy of $19,750,000 to LDS/LGSS customers. Under my subsequently discussed revenue distribution, I am recommending that LDS/LGSS customer revenues be increased to $26,924,334 (Table 3). Therefore, under my proposed revenue distribution, the subsidy being provided to LDS/LGSS customers would be $12,600,000. As indicated in Table 1, Flex rate customers currently provide a negative rate of return of 4.372 percent at present rates. To provide revenues equal to the cost of service indicated by the Company's Peak & Average Study at proposed rates, Flex rate customer revenue would need to be increased from the current level of $3,414,542 (Table 2) to approximately $32,300,000 or by $28,880,000. As such, other customers are providing a subsidy of $28,880,000 to Flex rate customers. In total, a subsidy of $41,480,000 is being provided to LDS/LGSS and Flex rate customers.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE ALLOCATION OF COLUMBIA'S PROPOSED REVENUE INCREASE?

A. Table 3 summarizes my recommended revenue distribution at proposed rates for the Company's claimed revenue deficiency and is based on Columbia's Peak & Average ACOS study. Also identified is the relative rate of return at proposed rates under my revenue distribution.

Table 3.
OCA Proposed Revenue Distribution

Class	Present Rates	Proposed Rates	Increase	Percent	Relative Rate of Return Present Rates	Relative Rate of Return Proposed Rates
RSS/RDS	$363,896,616	$423,614,914	$59,718,298	16.4%	1.26	1.17
SGSS1/SCD1/SGDS1	40,420,998	50,872,170	10,451,172	25.9	1.08	1.14
SGSS2/SCD2/SGDS2	44,580,611	55,793,814	11,213,2035	25.2	1.14	1.15
SDS/LGSS	26,687,078	36,384,937	9,697,859	36.3	0.95	1.14
LDS/LGSS	19,742,916	26,924,334	7,181,418	36.4	0.17	0.44
MLDS	1,111444	1,111,823	379	0.0	30.41	0.20
FLEX	3,398,752	3,414,542	15,790	0.5	(0.84)	(0.55)
Total:	**$499,838,415**	**$598,116,534**	**$98,278,118**	**19.7%**	**1.00**	**1.00**

Q. HOW DID YOU DEVELOP YOUR PROPOSED REVENUE DISTRIBUTION?

A. As indicated in Table 2, the LDS/LGSS rate class is providing a return which is significantly lower than the indicated cost of service (ROR of 0.38). While there is no hard and fast rule with respect to applying the concept of gradualism in developing a revenue distribution, typically an increase of 1.5 to 2.0 times the system average increase is considered consistent with the concept of gradualism. Therefore, I assigned an increase of 1.85 times the system average increase to the LDS/LGSS rate class. I accepted the Company's proposal concerning distribution of the revenue increase to the MLDS class since this class is providing a return which is significantly greater than the indicated cost of service.

Due to the $41,480,000 subsidy being provided to LDS/LGSS and Flex rate customers, it is necessary for other classes to pay rates in excess of the cost of service if Columbia is entitled to collect 100 percent of its cost of service. To calculate the subsidy being paid by the other remaining customer classes, I determined the revenues at proposed rates that would yield a ROR of 1.0 for each class, and subtracted the revenues at proposed rates under Columbia's revenue distribution. This analysis indicated that the RSS/RDS class was providing a subsidy, or overpaying, by $38,000,000. To provide a more reasonable sharing of the LDS/LGSS and Flex rate customer subsidy, I allocated the subsidy to each rate class, excluding the MLDS, LDS/LGSS and Flex rate classes based on rate base. For the SGSS1/SCD1/SGDS1, SGSS2/SCD2/SGDS2, and SDS/LGSS rate classes, I developed proposed revenues by adding the allocated subsidy to the revenues providing a ROR of 1.0. The additional revenues assigned to these three rate classes were then deducted from the revenue increase assigned by Columbia the RSS/RDS class. This resulted in additional movement toward the cost of service for the RSS/RDS rate class.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE SCALE-BACK OF YOUR PROPOSED REVENUE DISTRIBUTION TO REFLECT THE INCREASE ACTUALLY AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. In the event that Columbia's authorized increase is less than its requested increase, I recommend a proportionate scale-back of the increase for each rate class with the exception of the MLDS and Flex rate classes.

Q. IN DOCKET NO. R-2020-3018835, DID THE COMMISSION IMPOSE ANY REQUIREMENTS ON COLUMBIA TO JUSTIFY THE GRANTING OF RATE DISCOUNTS TO FLEX RATE CUSTOMERS?

A. Yes. Flex rate customers receive service at discounted rates due to competitive alternative fuel options. The Opinion and Order in Columbia's last base rate proceeding required the Company to prepare a Competitive Alternative Analysis for any Flex rate customer whose alternative fuel option had not been verified for a period of ten or more years in Columbia's next base rate case. (Order at 240-241)

Q. DID COLUMBIA FILE ANY COMPETITIVE ALTERNATIVE ANALYSES IN THIS PROCEEDING?

A. No. The Company contends that there are no discounted agreements currently over ten years old. In addition, in Docket No. R-2020-3018835, Columbia claimed it already verified the competitive alternatives for Flex rate customers when the Company has the option not to review an expiring Flex rate agreement or the ability to decline entering into a new Flex rate agreement.

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING THE COMPANY'S EVALUATION OF FLEX RATE CUSTOMER ALTERNATE FUEL SOURCES OR THE DISCOUNTS GIVEN TO FLEX RATE CUSTOMERS?

A. Yes, I have two recommendations:

- Prior to entering into a new contract or extending an existing contract for a Flex rate customer, Columbia should continue its practice of updating the Competitive Alternative Analysis to verify that the customer should continue to receive service at discounted rates. Each updated Competitive Alternative Analysis should be presented in the Company's next base rate proceeding.

- The Company's Flex rate customer receive a significant cost of service subsidy from customers paying Columbia's tariff rates. Therefore, each Competitive Alternative Analysis presented in the Company's next base rate case should also evaluate whether the revenues provided by the Flex rate customer exceeds the long-term marginal cost of service. Rates charged to Flex rate customers should be sufficient to recover the long-term marginal cost of service.

IV. RATE DESIGN

Q. PLEASE DESCRIBE COLUMBIA'S CURRENT AND PROPOSED RESIDENTIAL RATES.

A. Columbia's current Residential sales and transportation customer distribution rates consist of a $16.75-per-month customer charge and a single delivery charge of $7.2962 for each Dth of gas delivered. Columbia's proposed Residential rate would consist of a $19.33-per-month customer charge and a $8.8796-per-Dth delivery charge. Columbia justifies its proposed Residential customer charge as being less than a calculated customer charge of $24.23. The $24.23 calculated charge is based on Columbia's Customer-Demand Study exclusive of a customer component of distribution mains.

Q. SHOULD COLUMBIA'S PROPOSED RESIDENTIAL CUSTOMER CHARGE BE APPROVED?

A. No, for several reasons. First, Columbia's Residential customer charge proposal is out of line with the Residential customer charges of other NGDCs in the Commonwealth. Second, as discussed in the testimony of OCA Witness Colton, Columbia's proposal will have a disproportionate impact on low-income customers. Finally, a high fixed monthly customer charge is inconsistent with the Commission's general goal of fostering energy conservation.

Q. HOW DOES COLUMBIA'S RESIDENTIAL CUSTOMER CHARGE PROPOSAL COMPARE WITH THE MONTHLY RESIDENTIAL CUSTOMER CHARGES OF OTHER NGDCs IN THE COMMONWEALTH?

A. Table 4 provides a comparison of Columbia's Residential customer charge proposal with the customer charges of other Pennsylvania NGDCs. As shown there, Columbia's current charge is already the highest in the Commonwealth, and if adopted, Columbia's proposed monthly Residential customer charge would be significantly higher than that of any other NGDC in the Commonwealth.

Table 4.
Comparison of Residential Customer Charges for Pennsylvania NGDCs

Columbia Gas of Pennsylvania – Proposed	**$19.33**
Columbia Gas of Pennsylvania – Current	**16.75**
Peoples Gas	15.75
UGI Gas	14.60
Peoples Natural Gas	14.50
Philadelphia Gas Works	14.10
National Fuel Gas Company	12.00
PECO Energy Company	11.75

Q. WHY IS A HIGH FIXED MONTHLY CUSTOMER CHARGE INCONSISTENT WITH THE COMMISSION'S GENERAL GOAL OF FOSTERING ENERGY CONSERVATION?

A. The more revenue collected through the fixed monthly charge, the lower the volumetric charge. The higher the volumetric charge, the greater the incentive to lower usage.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO COLUMBIA'S MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. Columbia's monthly Residential customer charge is already the highest in the Commonwealth. Therefore, I recommend that the existing $16.75 monthly charge be maintained.

Q. DID COLUMBIA PROPOSE AN INCREASE IN ITS MONTHLY RESIDENTIAL CUSTOMER CHARGE IN ITS LAST BASE RATE CASE AND WAS THE INCREASE APPROVED?

A. Columbia proposed an increase in its existing monthly customer charge in Docket No. R-2020-3018835. In that proceeding the Administrative Law Judge ("ALJ") found that Columbia's proposed increase in the Residential customer charge was contrary to the Commission's goal of encouraging customers to conserve energy, and denied the Company's requested increase in the monthly customer charge. (Order, at 264). The Commission adopted the ALJ's decision regarding the Residential customer charge. (Order, at 265).

V. <u>REVENUE NORMALIZATION ADJUSTMENT</u>

Q. BRIEFLY DESCRIBE RIDER RNA PROPOSED BY COLUMBIA.

A. Under Rider RNA, Peak (October-March) and Off-Peak (April-September) benchmark revenue per Residential customer ("Benchmark Distribution Revenue per Bill" or "BDRB") levels would be established through a base rate case proceeding.[2] Through Rider RNA, the Company would collect or refund any variation in Residential revenues that differed from the BDRB not due to differences between actual and normal weather. Rider RNA would be calculated and assessed on a total Residential class revenue basis rather than an individual customer revenue basis.

Q. HAS THE COMMISSION ADOPTED A STATEMENT OF POLICY CONCERNING ALTERNATIVE RATE MAKING MECHANISMS SUCH AS RIDER RNA?

A. Yes. In an Order entered July 18, 2019, in Docket No. M-2015-2518883, the Commission set forth its Statement of Policy with respect to alternative ratemaking methodologies. In its Statement of Policy, the Commission identified 14 factors it would consider in evaluating an alternative ratemaking mechanism. The Statement of

[2] The RNA would not apply to Residential customer assistance program customers.

Policy required a utility proposing an alternative ratemaking mechanism to explain how each of these 14 factors impact the rates of each customer class.

Q. DOES THE COMPANY ADDRESS THESE 14 FACTORS IN ITS DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, the 14 factors are identified in the Direct Testimony of Mr. Notestone. Mr. Notestone also addresses how Rider RNA allegedly aligns with the Commission's Statement of Policy on alternative ratemaking.

Q. WHAT ARE THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING, WHAT IS MR. NOTESTONE'S RESPONSE TO THE 14 FACTORS, AND WHAT IS YOUR RESPONSE TO MR. NOTESTONE'S CLAIMS?

A. Each rate consideration identified in the Statement of Policy is listed below along with the claimed relevant effect of Rider RNA on each rate consideration. Also identified below is my response to the Company's claim:

Consideration 1 Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

COLUMBIA: Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.

OCA: The Company's response does not indicate how the mechanism aligns revenues with cost causation as to fixed and variable costs.

Consideration 2 Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

COLUMBIA: Columbia's RNA proposal has no identifiable effect on the capacity utilization of the residential class.

OCA: I agree with the Company's response.

Consideration 3 Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

COLUMBIA: Columbia's RNA benchmark revenue includes the anticipated volumetric base revenue derived from the fully projected test year consumption.

OCA: I agree with the Company's response.

Consideration 4 Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.

COLUMBIA: Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.

OCA: The RNA is only applicable to the Residential class and, therefore, does not affect interclass cost shifting. The Company's higher Residential customer charge proposal, which should be rejected, is unrelated to the RNA.

Consideration 5 Please explain how the RNA limits or eliminates disincentives for the promotion of efficiency programs.

COLUMBIA: Reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between level of throughput and base revenue recoveries is broken with the implementation of the RNA.

OCA: Columbia has not proposed any new energy efficiency programs in this proceeding.

Consideration 6 Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.

COLUMBIA: Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.

	OCA: The RNA reduces the incentive for Residential customers to pursue energy efficiency programs. Base rate revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA.
Consideration 7	Please explain how the RNA impacts low-income customers and support consumer assistance programs.
	COLUMBIA: Columbia's proposed RNA only applies to non-CAP customers.
	OCA: The RNA will not impact CAP customers.
Consideration 8	Please explain how the RNA impacts customer rate stability principles.
	COLUMBIA: Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.
	OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The RNA will not change this standard.
Consideration 9	Please explain how weather impacts utility revenue under the RNA.
	COLUMBIA: The RNA, as proposed will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.
	OCA: Weather will not impact utility revenue under the RNA.
Consideration 10	Please explain how the RNA impacts the frequency of rate case filings and affects regulatory lag.
	COLUMBIA: The RNA is designed to mitigate the over or under recovery of the residential cost of service in this case. Future rate cases would still be required to capture cost of service changes that occur beyond the residential class and the fully projected test year in this case.

	OCA: For a utility that files a rate case every 3 to 5 years, the RNA could reduce the frequency of filings. However, Columbia files a rate case nearly every year.
Consideration 11	Please explain if the RNA interacts with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).
	COLUMBIA: Columbia's proposed RNA only applies to the recovery of costs included in determination of the residential base revenue requirement.
	OCA: The RNA will not interact with other revenue sources.
Consideration 12	Please explain whether the RNA includes appropriate consumer protections.
	COLUMBIA: The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.
	OCA: The RNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony.
Consideration 13	Please explain whether the RNA is understandable to customers.
	COLUMBIA: Columbia's RNA is not a unique concept to the regulated utility industry and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing an RNA tariff that clearly shows the detail how the mechanism works.
	OCA: Columbia has not provided any evidence that the RNA will be understandable to customers.

Consideration 14	Please explain how the RNA will support improvements in utility reliability.
	<u>COLUMBIA</u>: Columbia's cost of service reflects the investments and costs made for the continued enhancement of the safety and reliability of its system. The RNA reduces the volatility concerning the recovery of those costs.
	<u>OCA</u>: The RNA does not provide an incentive to increase the safety and reliability of Columbia's system.

Q. SHOULD RIDER RNA BE APPROVED BY THE COMMISSION?

A. No. Rider RNA should not be approved for the following reasons:

- The proposed Rider RNA could increase earnings beyond those that the Company would ordinarily be entitled to.
- The proposed Rider RNA unreasonably applies to customers whose usage is relatively constant over time.
- The proposed Rider RNA embodies a take-or-pay pricing policy.
- The proposed Rider RNA inappropriately adjusts rates without considering other changes in total revenues and costs.
- Columbia has not demonstrated that its current system of rates and charges result in inadequate revenue stability.

Based on these concerns, Rider RNA should not be approved.

Q. PLEASE EXPLAIN HOW THE RNA COULD INCREASE EARNINGS BEYOND THOSE TO WHICH THE COMPANY WOULD ORDINARILY BE ENTITLED.

A. When Columbia adds a new Residential customer, margins from that customer are set under Rider RNA at the BDRB. A new customer is likely to have purchased a more energy-efficient gas appliance than an average existing customer, and would have lower usage than an average customer, all else being equal. This would increase Columbia's earnings beyond what they would have been without Rider RNA because Columbia's margins would be based on average Residential customer margins.

Q. DOES THE PROPOSED RIDER RNA UNREASONABLY APPLY TO CUSTOMERS WHOSE USAGE IS RELATIVELY CONSTANT OVER TIME?

A. Yes. Rider RNA would collect or refund any variation in total Residential revenues that differed from the BDRB and that are not due to differences between actual and normal weather. Therefore, Rider RNA would unreasonably apply to those Residential customers whose usage is relatively constant over time.

Q. DOES THE PROPOSED RIDER RNA EMBODY A TAKE-OR-PAY PRICING POLICY?

A. Yes. In the marketplace, consumers pay for the goods and services they receive. Under the proposed Rider RNA, consumers would pay for distribution service they do and do not receive. No matter how much distribution service is actually purchased by Columbia's Residential customers, ultimately, under the proposed Rider RNA, those customers would pay for the presumed level of service whether they take delivery or not. This conversion of a volumetric rate into rates that yield a given revenue, regardless of the amount of service purchased, converts Columbia's volumetric rate into a take-or-pay billing feature.

Q. PLEASE EXPLAIN HOW RIDER RNA COULD RESULT IN INAPPROPRIATE RATE ADJUSTMENTS.

A. The proposed Rider RNA operates to change rates, automatically, between rate cases, simply as a function of Residential distribution revenues being different from benchmark revenues due to factors other than weather. There is no review of Columbia's costs, or the volumes and attendant revenues from other customer classes that are not included under Rider RNA. For example, if Residential usage per customer were to fall over time, while SGSS1/SCD1/SGDS1 deliveries increased, Columbia's

Residential rates would be increased under Rider RNA with no recognition of the increased SGSS1/SCD1/SGDS1 distribution service revenues. Moreover, if Residential customer distribution service requirements decreased over time, Residential allocated costs should also decrease, thus reducing the Residential revenue requirement. There is no provision in the proposed Rider RNA to adjust Residential class revenue requirements as they may be affected by the very events that trigger automatic price changes under Rider RNA. The proposed Rider RNA can operate to delay base rate cases, leading to rate increases between base rate cases that may not be supported by a broader review of Columbia's revenue/cost relationship, and leading to Residential class revenue relationships that no longer reflect any basis in allocated costs of service.

Q. HAS COLUMBIA DEMONSTRATED THAT ITS CURRENT SYSTEM OF RATES AND CHARGES DO NOT PROVIDE FOR ADEQUATE REVENUE STABILITY?

A. No. Columbia's current system of rates and charges, which include fixed monthly customer charges, a Purchased Gas Adjustment mechanism, a Weather Normalization Adjustment, and a Distribution System Improvement Charge, provide for revenue stability and Columbia has not demonstrated that this stability is inadequate.

Q. DID THE COMPANY PROPOSE A SIMILAR RIDER RNA IN DOCKET NO. R-2020-3018835 AND WAS IT APPROVED BY THE COMMISSION?

A. The Company proposed a similar Rider RNA in its last base rate case. In that proceeding the ALJ determined that the Company failed to prove that the RNA would result in rates that were just and reasonable, in the public interest, and the Company did not demonstrate that its current rates and systems of revenue streams failed to provided revenue stability. (Order at 264-265). The Company did not file exceptions to the ALJ's recommended rejection of its proposed Rider RNA.

Q. ARE THERE OTHER REASONS THAT RIDER RNA SHOULD NOT BE APPROVED AT THIS TIME?

A. Yes. The COVID-19 pandemic is another reason Rider RNA should not be approved. There is a great deal of uncertainty concerning the impact of the pandemic on customer usage and unintended consequences could result. For example, the normal usage of Residential customers could change significantly as a result of the pandemic and customers could be assessed charges for these changes in usage. Alternative ratemaking mechanisms such as Rider RNA need to be accompanied by sufficient consumer protections.

VI. FEDERAL TAX REFORM ADJUSTMENT

Q. PLEASE DESCRIBE COLUMBIA'S PROPOSED FTRA.

A. The FTRA is a positive or negative percentage adjustment that would be applied to customer bills to account for changes in the Company's overall revenue requirement due to changes in the corporate Federal income tax rate.

Q. SHOULD THE FTRA BE APPROVED?

A. No. The current corporate Federal income tax rate was put into effect January 1, 2018 as a result of the Tax Cuts and Jobs Act ("TCJA"). In February 2018, this Commission initiated a generic proceeding to determine the effects of the TCJA on the tax liabilities of the public utilities it regulates. It is uncertain when the next change in the corporate Federal income tax rate will occur, and whether the legislation enacting the change will include other provisions which affect corporate Federal income tax liabilities. For example, the TCJA included provisions affecting the tax treatment of net operating loss carrybacks and caps and limited the net interest deduction. Given the uncertainties as to the specific provisions of any legislation changing the corporate Federal income tax rate, such changes should be addressed by the Commission on a generic basis for all the public utilities it regulates rather than on a piecemeal basis as proposed by Columbia.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does at this time.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts set forth in my Direct Testimony, OCA Statement 3, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 16, 2021
*311186

Signature: Jerome D. Mierzwa

Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 3-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2021-3024296
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

REBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

July 14, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement No. 3 on June 16, 2021.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimonies of James L Crist presented on behalf of Pennsylvania State University ("PSU"), Ethan H. Cline presented on behalf of the Bureau of Investigation and Enforcement ("I&E"), and Robert D. Knecht presented on behalf of the Office of Small Business Advocate ("OSBA").

II. PENNSYLVANIA STATE UNIVERSITY WITNESS: JAMES L. CRIST

Q. WHAT ALLOCATED COST OF SERVICE ("ACOS") STUDY METHOD DID COLUMBIA GAS OF PENNSYLVANIA ("COLUMBIA") RELY UPON TO DETERMINE THE DISTRIBUTION OF THE REVENUE INCREASE IT IS REQUESTING IN THIS PROCEEDING?

A. Columbia claims to have relied upon the Peak & Average method to determine the distribution of the revenue increase it is requesting in this proceeding because it was approved by the Commission in its last base rate proceeding.

Q. DOES MR. CRIST BELIEVE THAT THE PEAK & AVERAGE METHOD SHOULD BE RELIED UPON IN THIS PROCEEDING BECAUSE IT WAS APPROVED IN COLUMBIA'S LAST PROCEEDING?

A. No. Mr. Crist contends that, in Columbia's last proceeding (2020), the Administrative Law Judge ("ALJ") found in her Recommended Decision that Columbia's Customer-Demand ACOS would be the preferred method, but the Company's Customer-Demand study contained serious flaws. (PSU St. 1 at 12, lines 7-11). Therefore, the ALJ adopted the Peak & Average method rather than the Customer-Demand method. (PSU St. 1 at 13, lines 29 through 14, line 2). In its final order in the last proceeding (2020), the Commission was not persuaded to reverse the ALJ's Recommended Decision that adopted the Peak & Average ACOS study. (PSU St. 1 at 13, lines 28-29). Mr. Crist claims that the serious flaws in the Company's Customer-Demand ACOS study identified by the ALJ have now been eliminated. (PSU St. 1 at 13, lines 23-25). Mr. Crist explains that the allocation of mains costs has a significant impact on the results of an ACOS study. (PSU St. 1 at 13, lines 7-11). Mr. Crist claims that annual throughput, which is used to allocate 50 percent of mains costs under the Peak & Average method, is not used in the design of gas main piping and that the cost causes of gas mains is demand. (PSU St. 1 at 16, lines 7-9). Therefore, Mr. Crist believes that the Customer-Demand ACOS study method should be utilized in this proceeding. (PSU St. 1 at 16, line 12 through 17, line 4).

Q. WHAT IS YOUR RESPONSE TO MR. CRIST?

A. First, I would note that in the Company's Customer-Demand ACOS study, mains costs are allocated 46 percent based on demand and 54 percent based on the number of customers. In the Peak & Average ACOS study, mains costs are allocated 50 percent based on demand and 50 percent based on annual throughput. Therefore, it is not clear why, if mains are sized based on demands as Mr. Crist claims, the Customer-Demand method should be utilized in this case when it results in less of an allocation mains costs based on demand than the Peak & Average method.

Second, in its Order in Columbia's last proceeding (2020), the Commission specifically approved the use of the Peak & Average allocation methodology. This finding was not due to the errors in the Customer-Demand ACOS presented by Columbia in its last case (that have now been eliminated). Rather, the Commission's findings in Columbia's last proceeding concerning the use of the Peak & Average method are presented on pages 7 and 8 of my Direct Testimony:

> …we remain of the opinion that although mains serve customers, it is the throughput that determines the mains investment, not the number of customers served.
> (Order at 217).

Thus, the elimination of the errors in the Customer-Demand ACOS presented by Columbia in its last case should had no influence on the Commission's finding that the Peak & Average method is superior as throughput, and not the number of customers, determines the Company's mains investment.

III. BUREAU OF INVESTIGATION AND ENFORCEMENT WITNESS: ETHAN H. CLINE

Q. COLUMBIA HAS PROPOSED TO INCREASE THE FIXED MONTHLY RESIDENTIAL CUSTOMER CHARGE FROM $16.75 TO $19.33. DOES MR. CLINE AGREE WITH THE PROPOSED INCREASE IN THE CUSTOMER CHARGE?

A. Yes. Mr. Cline claims that the proposed increase in the monthly Residential customer charge is reasonable because it is supported by a customer cost analysis. (I&E St. 3 at 18, line 9 through 19, line 2).

Q. WHAT IS YOUR RESPONSE TO MR. CLINE'S FINDING THAT THE INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE SHOULD BE APPROVED?

A. Columbia's proposed increase in the Residential customer charge should not be approved for several reasons which are explained in greater detail in my Direct Testimony, as well as OCA witness Colton's Direct Testimony. First, Columbia's Residential customer charge proposal is out of line with the Residential customer charges of other natural gas distribution companies ("NGDCs") in the Commonwealth. Second, as discussed in the testimony of OCA Witness Colton, Columbia's proposal will have a disproportionate impact on low-income customers. Finally, a high fixed monthly customer charge is inconsistent with the Commission's general goal of fostering energy conservation. In the Company's last base rate proceeding Columbia's proposed increase in the Residential customer charge was not approved because it was inconsistent with the Commission's goal of encouraging customers to conserve energy.

IV. OFFICE OF SMALL BUSINESS ADVOCATE
WITNESS: ROBERT D. KNECHT

Q. IN HIS DIRECT TESTIMONY, DOES MR. KNECHT GENERALLY ACCEPTS THE USE OF THE COMPANY'S PEAK & AVERAGE ACOS STUDY IN THIS PROCEEDING BECAUSE IT WAS APPROVED BY THE COMMISSION IN THE COMPANY'S LAST RATE PROCEEDING?

A. Yes. (OSBA St. 1 at 14, lines 1-6).

Q. DOES MR. KNECHT AGREE WITH THE COMPANY'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE IT IS REQUESTING IN THIS PROCEEDING?

A. Mr. Knecht finds the Company's proposed revenue distribution not to be unreasonable. (OSBA St. 1 at 21, lines 8-9). However, based on the results of the Company's Peak & Average ACOS study, he does recommend that the Commission consider shifting $1.8 million from the Residential class to the Large General Service class. (OSBA St. 1 at 22, lines 23-24).

Q. WHAT IS YOUR RESPONSE TO THIS RECOMMENDATION?

A. As I explained in my Direct testimony, Columbia's proposed revenue distribution should be modified to reflect additional movement toward cost-based rates for each customer class, and to adequately account for the significant subsidy provided to Large General Service and Flex rate customers. To accomplish this, I proposed reducing the allocated increase to the Residential class by $8.1 million, and increasing the allocated increases to other customer classes by this amount, including an increase to the Large General Service class of $1.3 million. I would not oppose increasing the allocation to the Large General Service class by $1.8 million as proposed by Mr. Knecht.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 3-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 14, 2021
*313172

Signature: Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 3-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC	:	
UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
COLUMBIA GAS OF	:	
PENNSYLVANIA, INC.	:	

SURREBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

July 27, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My Direct Testimony was submitted as OCA Statement No. 3 on June 16, 2021, and my Rebuttal Testimony was submitted as OCA Statement No. 3-R on July 14, 2021.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the rebuttal testimonies of Melissa J. Bell and Jennifer Harding presented on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia"), Robert D. Knecht presented on behalf of the Office of Small Business Advocate, James L. Crist presented on behalf of Pennsylvania State University ("PSU"), and Frank Plank presented on behalf of the Columbia Industrial Intervenors.

II. COLUMBIA GAS OF PENNSYLVANIA, INC.
WITNESS: MELISSA J. BELL

A. Peak and Average Allocation

Q. ON PAGES 6 AND 7 OF COLUMBIA ST. NO. 3-R, MS. BELL, IN RESPONDING TO MR. CRIST'S DIRECT TESTIMONY, CLAIMS THAT IN COLUMBIA'S 2020 RATE CASE (DOCKET NO. R-2020-3018835), THE COMMISSION MAY HAVE APPROVED THE USE OF THE PEAK

AND AVERAGE ALLOCATED CLASS COST OF SERVICE ("ACOS") STUDY METHOD DUE TO THE ERRORS IN THE CUSTOMER-DEMAND ACOS STUDY PRESENTED BY THE COMPANY, AND THOSE ERRORS HAVE BEEN ELIMINATED IN THE CUSTOMER-DEMAND STUDY PRESENTED BY COLUMBIA IN THIS PROCEEDING. WHAT IS YOUR RESPONSE?

A. As explained in my Rebuttal Testimony, in its Order in Columbia's 2020 base rate proceeding, the Commission specifically approved the use of the Peak & Average allocation methodology. This finding was not due to the errors in the Customer-Demand ACOS study presented by Columbia in its last case that have now been eliminated. Rather, the Commission's findings in Columbia's last proceeding concerning the use of the Peak & Average method were presented on pages 7 and 8 of my Direct Testimony:

> …we remain of the opinion that although mains serve customers, it is the throughput that determines the mains investment, not the number of customers served. (Order at 217).

The Customer-Demand ACOS study allocates a significant percent of distribution mains costs based on the number of customers. Thus, the elimination of the errors in the Customer-Demand ACOS study presented by Columbia in its last case had no influence on the Commission's finding that the Peak & Average method is superior as throughput, and not the number of customers, determines the Company's mains investment.

Q. MS. BELL PRESENTS AN ANALYSIS WHICH SHE CLAIMS INDICATES THAT THE PEAK AND AVERAGE ACOS STUDY METHOD ASSIGNS AN AVERAGE OF 13 MILES OF MAIN TO EACH

LDS/LGSS CUSTOMER BUT THE COMPANY WAS ONLY REQUIRED TO EXTEND ITS SYSTEM IN THE RANGE OF 0.1 TO 1.4 MILES TO CONNECT ITS 10 LARGEST CUSTOMERS TO ITS SYSTEM. WHAT DOES MS. BELL CONCLUDE FROM THIS ANALYSIS?

A. Based on her analysis, Ms. Bell claims that the Peak and Average method allocates an excessive amount of mains costs to the LDS/LGSS rate class.[1] Therefore, she contends that using the Peak and Average method as the sole basis of determining the allocation of revenue is not fair, or reasonable.

Q. WHAT IS YOUR RESPONSE TO MS. BELL'S ANALYSIS AND CLAIMS?

A. Ms. Bell's analysis is incomplete and, therefore, her claims should be dismissed. Her claim that the Company was only required to extend its system in the range of 0.1 to 1.4 miles to connect its 10 largest customers is based on the distances between each large customer and the next upstream customer meter. This fails to account for the main investment upstream of the next upstream customer that is utilized to serve each large customer. That is, more than 0.1 to 1.4 miles of main is utilized to serve each large customer connected to its system.

B. <u>LDS/LGSS Cost Assignment</u>

Q. ON PAGE 14 OF COLUMBIA ST. NO. 3-R, MS. BELL CONTENDS THAT THE 1.85 TIMES SYSTEM AVERAGE INCREASE YOU HAVE ASSIGNED TO THE LDS/LGSS CLASS IS INCONSISTENT WITH THE CONCEPT OF GRADUALISM. WHAT IS YOUR RESPONSE?

A. As I explained in my Direct Testimony, there is no hard and fast rule with respect to applying the concept of gradualism, and typically an increase of 1.5 to 2.0 times the

[1] Columbia St. No. 3-R at 12-14.

system average increase is considered consistent with the concept of gradualism. In his Rebuttal Testimony, Mr. Knecht acknowledges this "rule-of-thumb" for gradualism. Under Columbia's proposed revenue allocation, the relative rate of return of the LDS/LGSS class is 0.38. Given that the LDS/LGSS rate class would be providing a return which is significantly lower than the indicated cost of service under Columbia's proposed revenue allocation of a 1.5 times system average increase, I believe the 1.85 times system average increase is appropriate for the LDS/LGSS rate class.

C. Flex Rate Analysis

Q. MS. BELL CONTENDS THAT THERE SHOULD NOT BE A MANDATE AS TO THE TYPE OF ANALYSIS OR INFORMATION COLUMBIA DEVELOPS TO SUPPORT GRANTING A FLEX RATE. WHAT IS YOUR RESPONSE?

A. Ms. Bell does not believe that the Company should be required to evaluate whether the revenues provided by a Flex rate customer exceed the long-term marginal cost of service.[2] I disagree. Rates charged to Flex rate customers should be sufficient to recover the long-term marginal cost of service. If rates are not sufficient to recover the long-term marginal cost of service, Columbia will incur avoidable costs to directly serve a Flex rate customer which will not be recovered from that Flex rate customer. Under these circumstances, there would be no benefit to serving the Flex rate customer over the long term.

D. Residential Customer Charge

Q. IN YOUR DIRECT TESTIMONY, YOU STATE "COLUMBIA'S MONTHLY RESIDENTIAL CUSTOMER CHARGE IS ALREADY THE HIGHEST IN THE COMMONWEALTH. THEREFORE, I RECOMMEND

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[2] Columbia St. No. 3-R at 15-16.

THAT THE EXISTING $16.75 MONTHLY CHARGE BE MAINTAINED." WHAT IS MS. BELL'S RESPONSE TO THIS RECOMMENDATION?

A. Ms. Bell does not dispute my claim that Columbia's current monthly Residential charge is already the highest in the Commonwealth, but contends that Columbia's Residential customer charge should not be determined by the cost of service of other natural gas distribution companies ("NGDCs") in Pennsylvania.[3]

Q. WHAT IS YOUR RESPONSE TO MS. BELL?

A. Columbia is proposing to increase its current monthly Residential customer charge from $16.75 to $19.33. The additional proposed increase would further increase the difference between Columbia's Residential customer charge and those of the other major Pennsylvania NGDCs. With the strains on household budgets attributable to the economic conditions caused by the COVID-19 pandemic, increasing fixed charges limits the benefits Residential customers can realize from engaging in conservation actions and their ability to address budgetary strains. Promotion of energy conservation has been a longstanding energy policy of the Commonwealth. To promote the Commonwealth's policy goals to encourage conservation and provide the Residential customers of Pennsylvania's largest NGDCs comparable opportunities to control their heating bills, Columbia's current monthly Residential customer charge should not be increased.

E. <u>Revenue Normalization Adjustment</u>

Q. IN YOUR DIRECT TESTIMONY, YOU ADDRESS THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING IN RESPONDING TO THE COMPANY'S PROPOSED REVENUE

[3] Columbia St. No. 3-R at 23-24.

NORMALIZATION ADJUSTMENT ("RNA") RIDER. HOW DOES MS. BELL RESPOND?

A. Ms. Bell notes that of the 14 factors, I agreed in principle with Columbia on eight considerations. She then comments on those considerations where I differed from Columbia. Below, I identify each consideration in which I continue to differ as well as: Columbia's initial response, my initial response, Ms. Bell's comments, and my response to Ms. Bell's comments.

> Consideration 1: Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
>
> COLUMBIA: Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.
>
> OCA: The Company's response does not indicate how the mechanism aligns revenues with cost causation as to fixed and variable costs.

Ms. Bell claims that the RNA is designed to recover/pass back the under/over amount charged by the variable base rates for the recovery of those fixed and variable costs caused by the change in usage per customer.[4] She therefore claims that the RNA more closely aligns actual revenues to costs.

Under the RNA, all Residential customers will be assessed the same "Benchmark Distribution Revenue per Bill," or BDRB, regardless of whether a customer's usage contributed to an under- or over-recovery. That is, if an overall under-recovery for the Residential class occurs, all customers will be assessed the same

[4] Columbia St. No. 3-R at 27-28.

BDRB, including those customers whose usage increased and resulted in an over-recovery of costs. Under these circumstances, the RNA does not align actual revenues to costs.

Consideration 6	Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.
	COLUMBIA: Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.
	OCA: The RNA reduces the incentive for Residential customers to pursue energy efficiency programs. Base rate revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA.

Ms. Bell claims that when an individual Residential customer decides to reduce their usage, the customer pays less to the Company through their volumetric charge.[5] She explains the shortfall in base revenue from the customer will be made up by the entire Residential class, not just the customer that chose to conserve, implying that the incentive to conserve would still exist under the RNA. Ms. Bell fails to recognize that the shortfall in base revenue would also be recovered from the customer that chose to conserve, reducing the incentive for the customer to conserve by pursuing energy efficiency programs.

Consideration 8	Please explain how the RNA impacts customer rate stability principles.
	COLUMBIA: Columbia's proposed RNA enables the recovery of costs established

[5] Columbia St. No. 3-R at 28-29.

in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.

OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The RNA will not change this standard.

Ms. Bell claims that absent the RNA, when the billing determinants used in a rate case to design rates are different than the usage per customer currently experienced, the Company's only option is to file a base rate case.[6] In response, I would note that in the last 14 years, Columbia has filed 10 rate cases. Ms. Bell has not claimed that the RNA will reduce the frequency of Columbia's rate case filings.

Consideration 12	Please explain whether the RNA includes appropriate consumer protections.
	COLUMBIA: The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.
	OCA: The RNA does not include appropriate consumer protections and

[6] Columbia St. No. 3-R at 29.

should be rejected for the reasons subsequently discussed in my testimony.

Ms. Bell claims that I gave no examples or support for my conclusion that the RNA does not include appropriate consumer protections.[7] In my direct testimony, I gave several examples as to why the RNA does not include appropriate consumer protections.[8] More specifically, I indicated that the RNA:

- Could increase earnings beyond those that the Company would ordinarily be entitled;
- Unreasonably applies to customers whose usage is relatively constant over time;
- Embodies a take-or-pay pricing policy; and
- Inappropriately adjusts rates without considering other changes in total revenues and costs.

Q. MS. BELL NOTES THAT IN YOUR DIRECT TESTIMONY YOU STATE "A NEW CUSTOMER IS LIKELY TO HAVE PURCHASED A MORE ENERGY-EFFICIENT GAS APPLIANCE THAN AN AVERAGE EXISTING CUSTOMER, AND WOULD HAVE LOWER USAGE THAN AN AVERAGE CUSTOMER, ALL ELSE BEING EQUAL. THIS WOULD INCREASE COLUMBIA'S EARNINGS BEYOND WHAT THEY WOULD HAVE BEEN WITHOUT RIDER RNA BECAUSE COLUMBIA'S MARGINS WOULD BE BASED ON AVERAGE RESIDENTIAL CUSTOMER MARGINS." WHAT IS HER RESPONSE TO THOSE STATEMENTS?

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[7] Columbia St. No. 3-R at 30.

[8] See, OCA St. 3 at 22.

A. Ms. Bell claims that my statements are not accurate.[9] She contends that although new homes are more energy efficient than existing homes, they are also, on average, larger, and therefore use more gas than existing homes. She presents an analysis which she contends shows that the forecasted usage of newly constructed homes is higher than the usage of existing homes.

Q. WHAT IS YOUR RESPONSE?

A. Ms. Bell's claims that a new home would use more gas than an existing home is based on usage projections developed by the Company and is inconsistent with the findings of a study conducted by the National Association of Home Builders ("NAHB"). A special study conducted by the NAHB found that:

> Newer homes are larger, but over the long run the effects of increased efficiency more than offsets the extra square footage.[10]

Q. ON PAGE 32 OF COLUMBIA ST. NO. 3-R, MS. BELL DISAGREES WITH YOUR CLAIM IN YOUR DIRECT TESTIMONY THAT THE COMPANY'S PROPOSED RNA SHOULD NOT BE ASSESSED TO CUSTOMERS WITH CONSTANT USAGE. WHAT IS YOUR RESPONSE?

A. Under the RNA, a BDRB would be established for Residential customers through a base rate case proceeding. The RNA would collect or refund any variation in total Residential revenues that differed from the BDRB and that are not due to differences between actual and normal weather. Therefore, it would be unreasonable to apply the RNA to those Residential customers whose usage is relatively constant over time.

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9 Columbia St. No. 3-R at 31-32.

10 www.nahbclassic.org/generic/aspx?section10=734GenericContentID=23790&print=true.

Q. ON PAGES 32 AND 33 OF HER REBUTTAL TESTIMONY, MS. BELL ALSO DISAGREES WITH YOU THAT THE RNA IS EQUAL TO A "TAKE-OR-PAY" ARRANGEMENT. WHAT IS YOUR RESPONSE?

A. Under the proposed RNA, consumers would pay for distribution service they do and do not receive. No matter how much distribution service is actually purchased by Columbia's Residential customers, ultimately, under the proposed RNA, those customers would pay for the presumed level of service whether they take delivery or not. This is how take-or-pay arrangements are structured.

Q. ON PAGE 23 OF YOUR DIRECT TESTIMONY YOU STATE, "THE PROPOSED RIDER RNA OPERATES TO CHANGE RATES, AUTOMATICALLY, BETWEEN RATE CASES, SIMPLY AS A FUNCTION OF RESIDENTIAL DISTRIBUTION REVENUES BEING DIFFERENT FROM BENCHMARK REVENUES DUE TO FACTORS OTHER THAN WEATHER. THERE IS NO REVIEW OF COLUMBIA'S COSTS, OR THE VOLUMES AND ATTENDANT REVENUES FROM OTHER CUSTOMER CLASSES THAT ARE NOT INCLUDED UNDER RIDER RNA." DOES MS. BELL AGREE?

A. No. Ms. Bell claims that I allege that if Residential usage per customer were to fall over time, while SGSS1/SCD1/SGDS1 deliveries increased, Columbia's Residential rates would be increased under the RNA with no recognition of the increased SGSS1/SCD1/SGDS1 distribution revenues.[11] She claims that this statement is flawed because I assume that higher SGSS1/SCD1/SGDS1 usage is not associated with higher costs and it is possible that the higher usage could result in incremental costs.

Q. WHAT IS YOUR RESPONSE?

[11] Columbia St. No. 3-R at 33-34.

A. If the decline in Residential usage was offset by an increase in SGSS1/SCD1/SGDS1 usage so that overall usage remained the same, I believe it likely that Columbia's costs would remain the same. The RNA does not provide for the review of revenues from other classes and would not recognize the increase in SGSS1/SCD1/SGDS1 revenues that Columbia would experience.

Q. MS. BELL DISAGREES WITH YOUR ASSERTION THAT COLUMBIA'S CURRENT SYSTEM OF RATES AND CHARGES ALREADY PROVIDES FOR REVENUE STABILITY. WHAT IS YOUR RESPONSE?

A. Ms. Bell claims that the Company's Purchased Gas Adjustment ("PGA") mechanism does not provide for revenue stability.[12] This claim is misplaced. My testimony was referring to base rate revenue stability. The PGA mechanism provides for dollar-for-dollar recovery of Columbia's purchased gas costs which eliminates the impact of purchase gas costs on base rate revenue. In addition, Ms. Bell claims that the Company's DSIC is capped at 5 percent and, therefore, limits its usefulness. I would note that Columbia's current DSIC is 0.10 percent, and is not being fully utilized.[13] Ms. Bell has not demonstrated that Columbia's current system of rates and charges do not provide sufficient revenue stability.

Q. ON PAGE 24 OF YOUR DIRECT TESTIMONY YOU STATE "THE COMPANY PROPOSED A SIMILAR RIDER RNA IN ITS LAST BASE RATE CASE. IN THAT PROCEEDING THE ALJ DETERMINED THAT THE COMPANY FAILED TO PROVE THAT THE RNA WOULD RESULT IN RATES THAT WERE JUST AND REASONABLE, IN THE

[12] Columbia St. No. 3-R at 34-35.

[13] See, Columbia Gas of Pennsylvania, Inc. – Rider Distribution System Improvement Charge ("DSIC") Quarterly Update Pursuant to 66 Pa.C.S. §§ 1357(a)(2) and 1357(d)(3), Docket No. P-2012-2338282, (filed June 21, 2021).

PUBLIC INTEREST, AND THE COMPANY DID NOT DEMONSTRATE THAT ITS CURRENT RATES AND SYSTEMS OF REVENUE STREAMS FAILED TO PROVIDED REVENUE STABILITY. (ORDER AT 264-265)."

WHAT WAS MS. BELL'S RESPONSE?

A. Ms. Bell claims that because no exceptions to the ALJ's Recommended Decision were filed, full arguments were not presented to the Commission in the last case.[14]

Q. WHAT IS YOUR RESPONSE?

A. In Columbia's last base rate proceeding, the Commission' Order found that the ALJ's recommendation was supported by ample evidence and was just and reasonable. (Order at 265). Therefore, based on the Commission's Order, it appears that all relevant factors were considered by the Commission.

III. COLUMBIA GAS OF PENNSYLVANIA, INC.
WITNESS: JENNIFER HARDING

F. Federal Tax Reform Adjustment Rider

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT THE COMPANY'S FEDERAL TAX REFORM ADJUSTMENT ("FTRA") RIDER NOT BE APPROVED. WHAT WAS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommended that the FTRA Rider not be approved because it is uncertain when the next change in the corporate tax rate will occur and such changes should be addressed by the Commission on a general basis for all public utilities.

Q. DOES MS. HARDING AGREE WITH YOUR RECOMMENDATION CONCERNING THE FTRA RIDER?

[14] Columbia St. No. 3-R at 35-36.

A. No. While Ms. Harding agrees that no one can say with any certainty if or when an increase to the federal corporate income tax rate will occur, she claims that the change may impact whether a utility's existing rates are "just and reasonable."[15]

Q. WHAT IS YOUR RESPONSE TO MS. HARDING?

A. The Commission determines whether a utility's rates are "just and reasonable," not the utility. Therefore, the impact of changes to the corporate tax rate should be addressed by the Commission on a generic basis as was done with the recent Tax Cuts and Jobs Act ("TCJA"). In addition, as explained in my Direct Testimony, the legislation enacting the tax change may include other provisions which affect corporate federal income tax liabilities which would need to be addressed by the Commission on a generic basis.[16] I would note that the Federal Energy Regulatory Commission addressed the changes associated with the TCJA on a generic basis in Order No. 849.

IV. OFFICE OF SMALL BUSINESS ADVOCATE WITNESS: ROBERT D. KNECHT

Q. DOES MR. KNECHT AGREE WITH YOUR PROPOSED REVENUE ALLOCATION?

A. While Mr. Knecht does not find my proposed revenue allocations to be unreasonable, he finds my proposed increase to the rates of the SGS1 and SGS2 classes past full cost recovery, and, to propose a similar magnitude increase for the SDS/LGS and LDS/LGSS classes, to be inequitable.[17]

Q. WHAT IS YOUR RESPONSE TO MR. KNECHT?

A. As indicated in my Direct Testimony, a $41,480,000 subsidy is being provided to the LDS/LGSS class and Flex rate customers. If Columbia is entitled to collect 100 percent

[15] Columbia St. No. 10-R at 2-4.
[16] See, OCA St. 3 at 25-26.

[17] OSBA St. 1-R at 5-6.

of its cost of service, it is necessary for other classes to pay rates in excess of the cost of service. My proposal to increase the rates of the SGS1 and SGS2 classes past full cost recovery provides for the recovery of a reasonable portion of the $41,480,000 subsidy from the SGS1 and SGS2 classes. I also increased the rates of the SDS/LGSS class past full recovery to provide for the recovery of a portion of the $41,480,000 subsidy. To be consistent with the principle of gradualism, I assigned an increase of 1.85 times the system average increase to the LDS/LGSS class. For the SDS/LGSS and LDS/LGSS classes, these allocations resulted in increases of a similar magnitude. As indicated in my Rebuttal Testimony, I would not oppose Mr. Knecht's proposal to increase the rates of the LDS/LGSS class by an additional $1.8 million.

V. PENNSYLVANIA STATE UNIVERSITY
WITNESS: JAMES L. CRIST

Q. ON PAGES 2-3 OF PSU ST. NO. 1-R, MR. CRIST CLAIMS THAT YOU HAVE PROPOSED TO INCREASE FLEX CUSTOMER RATES BY AN ADDITIONAL $15,790. IS THAT YOUR PROPOSAL?

A. No. A comparison of Tables 2 and 3 in my Direct Testimony indicates that I have proposed the same increase for Flex rate customers as proposed by Columbia.[18]

Q. MR. CRIST CLAIMS YOUR PROPOSAL TO INCREASE THE RATES OF LDS/LGSS CUSTOMERS IS "UNCONSCIONABLE." WHAT IS YOUR RESPONSE?

A. As indicated in Table 3 of my Direct Testimony, at present rates, LDS/LGSS revenues are significantly below the indicated cost of service with a relative rate of return ("ROR") of 0.17. A ROR of 1.0 would indicate that revenues are fully recovering the indicated cost of service. Based on the result of the ACOS study method approved by

[18] See, OCA St. 3 at 10 and 12.

the Commission in the Company's 2020 base rate case, I have proposed an increase of 1.85 times the system average increase for the LGSS class which is consistent with the principle of gradualism. Even with this increase, rates for the LDS/LGSS class would still be significantly under-recovering the indicated cost of service with a ROR of 0.44. This is not unconscionable.

Q. WHAT IS MR. CRIST'S RECOMMENDATION CONCERNING THE ACOS STUDY THAT SHOULD BE USED IN THIS PROCEEDING?

A. Mr. Crist claims that, despite being the preferred method, Columbia's Customer-Demand ACOS study was rejected in the Company's 2020 base rate proceeding because it had serious flaws and errors and, therefore, the Commission accepted the Company's Peak and Average ACOS study.[19] Mr. Crist recommends that since those flaws and errors have been eliminated in the Customer-Demand ACOS study filed by Columbia in this proceeding, Mr. Crist recommends that the Customer-Demand study should be utilized in this proceeding.

Q. WHAT IS YOUR RESPONSE TO MR. CRIST'S CLAIM?

A. As explained in my Rebuttal Testimony and previously in responding to Ms. Bell earlier in this Surrebuttal Testimony, in its Order in Columbia's last proceeding, the Commission specifically approved the use of the Peak & Average allocation methodology. This finding was not due to the errors in the Customer-Demand ACOS study presented by Columbia in its last case that have now been eliminated. Rather, the Commission's findings in Columbia's last proceeding concerning the use of the Peak & Average method were presented on pages 7 and 8 of my Direct Testimony:

> …we remain of the opinion that although mains serve customers, it is the throughput that determines the mains investment, not the number of customers served.

[19] PSU St. No. 1-R at 3-4.

(Order at 217).

Thus, the elimination of the errors in the Customer-Demand ACOS study presented by Columbia in its last case had no influence on the Commission's finding that the Peak & Average method is superior as throughput, and not the number of customers, determines the Company's mains investment.

Q. HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE ALLOCATION OF DISTRIBUTION MAINS COSTS BASED ON THE NUMBER OF CUSTOMERS IN OTHER PROCEEDINGS?

A. Yes. In Philadelphia Gas Works, Docket No. R-00061931, 2007 PA. PUC LEXIS 46 (2007), the Commission found that mains allocations based on the number of customers was not acceptable.

Q. MR. CRIST CLAIMS THAT THE MARYLAND PUBLIC SERVICE COMMISSION ("MPSC") APPROVED IN A BALTIMORE GAS AND ELECTRIC COMPANY PROCEEDING AN ACOS STUDY METHOD WHICH ALLOCATES MAINS INVESTMENT BASED ON NON-COINCIDENT PEAK DEMANDS. WHAT IS YOUR RESPONSE?

A. In Washington Gas Light Company ("WGL"), Case No. 9322, the MDPSC found "…that the CCOSS and accompanying demand study were sufficient for purposes of rate design and that the Proposed Order fairly assigned costs to each customer class, including non-residential customer classes." (Order No. 86013, Issued November 22, 2013). In that proceeding WGL's cost of service study utilized the Peak & Average approach to the allocation of distribution mains. In WGL's base rate proceeding in Case No. 9481, the cost of service study presented by WGL again used the Peak & Average method to allocate distribution mains, and WGL's cost of service study was accepted by the MDPSC (Order No. 88944, Issued December 11, 2018). In WGL's base rate proceeding in Case No. 9605, the cost of service study filed by WGL also utilized the Peak & Average method. That proceeding was resolved by settlement.

Q. MR. CRIST CITES PROCEEDINGS IN OTHER JURISDICTIONS IN WHICH COMMISSIONS HAVE ADOPTED CUSTOMER-DEMAND ACOS STUDIES. ARE YOU AWARE OF PROCEEDINGS IN WHICH COMMISSIONS HAVE ADOPTED PEAK AND AVERAGE ACOS STUDIES?

A. Yes. The Indiana Utility Regulatory Commission ("IURC") has strongly endorsed the use of the Peak & Average methodology. See In re Citizens Gas & Coke Utility, IURC Case No. 42767 (Oct. 19, 2006). The IURC found that the Peak & Average method was the "equitable and realistic" method for allocating distribution mains costs, and provided the following analysis:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding.
>
> While we do not doubt that distribution mains must be constructed with peak demand in mind, distribution mains do not only serve customers on peak demand days. Therefore, a measure of the costs of distribution mains must be allocated to customers based on their usage that takes place on non-peak days. For example, a customer that does not take service at all on the peak demand day-and therefore contributes nothing to peak demand requirements of distribution mains-but receives service through distribution mains at other times should be responsible for some portion of distribution main costs.
>
> The OUCC's approach is much more equitable and realistic. Rather than allocating distribution main

> costs exclusively based on either peak demand day or average annual consumption, the OUCC used a compromise approach that allocated these costs based on both. Under the OUCC's cost-of-service study, 80% of distribution main costs are allocated based on average demand. (Public's Ex. No. 6 at 13.) In this way, the OUCC's approach allocates part of distribution main costs to customers who receive service through distribution mains throughout the year but who may not receive much or any service on the peak demand day.
>
> For the reasons set forth above, we find the OUCC's cost-of-service study most accurately reflects the manner in which distribution main costs are actually incurred. See, In Re Citizens Gas & Coke Utility, IURC Cause No. 39066, at 31 (Nov. 1, 1999). We therefore adopt the OUCC's cost-of-service study to implement the rates increase approved in this Cause.
>
> [<u>In re Citizens Gas & Coke Utility</u>, IURC Cause No. 42767, at 74-75 (Oct. 19, 2006)]

The Illinois Commerce Commission ("ICC") has also accepted the Peak & Average method for allocating transmission and distribution costs in the natural gas industry. The ICC explained the reasoning behind utilizing a Peak & Average methodology in their decision as follows:

> Generally, [Central Illinois Public Service Company or CIPS] and [Union Electric Company or UE] gas transmission and distribution facilities exist because there is a daily need for such facilities. Regardless of when CIPS and UE experience their respective peak and the level of the peak, customers depend on the continued operation of the Ameren gas transmission and distribution systems to meet their daily needs. On the day that the peak does occur. Ameren's own Mr. Carls testifies that CIPS' and UE's respective systems are built to accommodate the system peak without regard to each class' peak. In light of the nature in which the transmission and distribution systems are used and because of the relatively declining cost of increasing capacity,

> peak demand is not the appropriate emphasis in allocating demand costs…As the Commission concluded in Docket 94-0040, a utility can not justify its transmission and distribution investment on demands for a single day. The allocation method that properly weights peak demand is the [Average & Peak or A&P] method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.
>
> [Central Ill. Pub. Service Co. Proposed General Increase in Natural Gas Rates, et al., 2003 Ill. PUC Lexis 824, 231-232 (2003)]

VI. COLUMBIA INDUSTRIAL INTERVENORS WITNESS: FRANK PLANK

Q. IN REBUTTAL, MR. PLANK CLAIMS THAT THE 36 PERCENT INCREASE YOU HAVE PROPOSED FOR THE LDS/LGSS CLASS IS EXCESSIVE. WHAT IS YOUR RESPONSE?

A. PSU witness Mr. Crist also opposed my proposed increase for the LDS/LGSS class, and I presented my justification for that increase in responding to Mr. Crist earlier in my Surrebuttal Testimony.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 3-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 27, 2021
*314209

Signature: Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

	:	
Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania	:	
	:	

Direct Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4

June 16, 2021

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of Rhode Island, New York, Maryland, Pennsylvania, Tennessee, Kentucky, Ohio, Michigan, and Missouri. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Illinois Office of Attorney General), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., National Immigration Law Center, Natural Resources Defense Council, Advocacy Centre Tenants Ontario), and private utilities (e.g., Unitil Corporation d/b/a Fitchburg Gas and Electric Company, Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, in 2011, I worked with the U.S. Department of Health and Human Services (the federal LIHEAP office) to advance the review and utilization of the Home Energy Insecurity Scale as an outcomes measurement tool for the federal Low-Income Home Energy Assistance Program ("LIHEAP"). In 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. In 2020, I completed a study of water affordability in twelve U.S. cities for the London-based newspaper, The Guardian. A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (regulatory economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. A description of my publications is included in Appendix A.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on numerous occasions regarding utility issues affecting low-income customers and customer service. I have also testified in regulatory proceedings in more than 35 states and various Canadian provinces on a wide range of utility issues. A list of the jurisdictions in which I have testified is provided in Appendix A.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is as follows.

- First, I examine the need for Columbia Gas to respond to the ongoing economic crisis associated with the COVID-19 health pandemic.

- Second, I examine the reasonableness of CPA's proposal to increase its residential customer charge. This examination is necessary only if CPA's request for increased rates is granted.

- Third, I examine the reasonableness of Columbia Gas's Customer Assistance Program (CAP) outreach directed toward its low-income customers. This examination is needed whether or not CPA is granted a rate increase in this proceeding.

- Fourth, I recommend deferring any examination of the allocation of CPA's universal service costs amongst customer classes to a future rate case.

- Finally, I examine certain cost-recovery issues presented by CPA's universal service rider.

Summary of Recommendations

Q. PLEASE PROVIDE A SUMMARY OF THE RECOMMENDATIONS YOU MAKE IN YOUR DIRECT TESTIMONY.

A. Based on the data and analysis presented throughout my Direct Testimony, I recommend as follows:

- Without recommending that it be funded through a reduction in otherwise available hardship funds, I recommend that the Company implement an Emergency Relief Program (ERP) such as it previously proposed. To control costs, I recommend that: (1) the Columbia Gas arrearage credits be limited to customers with an unpaid balance of more than 60 days old; and (2) the proposed cost control mechanism of limiting arrearage grants to $200 or 25% of the outstanding balance, whichever is more (with the creation of credit balances not being permitted). I recommend the program operate through June 2022, unless by motion of a stakeholder or on the Commission’s own motion, it is ended before then. I recommend that Columbia Gas carefully track the number of its ERP recipients who subsequently become a CAP participant. Columbia Gas should be prepared to explain to the Commission and to other stakeholders what proportion of its ERP arrearage credits it would have been required to spend through arrearage forgiveness even without an ERP. Finally, I recommend that Columbia Gas accrue its ERP costs as a regulatory asset the recovery of which will be determined in its next base rate case.

- I recommend that the residential customer charge recommended by OCA witness Jerome Mierzwa be adopted.

- I recommend that the Commission direct Columbia Gas to develop remedies for its exits from CAP relating to failure to recertify and due to customer mobility. The Company should be specifically directed to report back to the Commission on the number of CAP participants who were removed from CAP because the CAP participant “moved” but nonetheless remained within the Columbia Gas service territory. Those CAP participants should be reinstated to CAP without further action on the part of the customer. In addition, the Company should be directed to report to the Bureau of Consumer Services the affirmative steps it will take to reduce the percentage of exits attributable to a failure to recertify.

- I recommend that Columbia be directed to provide a detailed plan addressing how it intends to expand its CAP outreach to expand CAP participation. Consistent with the Commissioners' statement in the recent decision in Columbia's last base rate case, that Plan should include not only a discussion of the activities that the Company intends to take, it should also include quantitative outcomes by which the success (or lack thereof) can be measured.

- I recommend that Columbia Gas be required to reduce its USP Rider charge to reflect reduced CAP administrative costs in 2020.

Part 1. Response to Ongoing COVID-19 Economic Crisis.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I document the ongoing economic emergency facing residential customers as caused by the past and ongoing impacts of the COVID-19 pandemic. I review the Columbia Gas response, as well as its proposed response, to that economic emergency and recommend modifications.

Q. PLEASE EXPLAIN THE DATA UPON WHICH YOU BASE YOUR DISCUSSION OF COVID-19 IMPACTS IN PENNSYLVANIA.

A. I base my discussion of Pennsylvania below largely on the Census Bureau's Phase 3.1 PULSE Survey. According to the Census Bureau, "[t]he Household Pulse Survey is designed to deploy quickly and efficiently, collecting data to measure household experiences during the coronavirus pandemic." Data collection for Phase 3 of the Household Pulse Survey ran from October 28, 2020 – March 29, 2021 and is now closed. Data collection for the next Phase of the survey (Phase 3.1) began on April 14, 2021.

Q. IS THE DATA FROM THE PULSE SURVEY THAT YOU EXAMINE SPECIFIC TO THE COLUMBIA GAS SERVICE TERRITORY?

A. No. While the Census releases data on various metropolitan areas, including Philadelphia, it does not release data on geographic areas that could be aggregated into the Columbia Gas service territory. Accordingly, I examine state-specific data for Pennsylvania as a whole. The data I examine is primarily from Week 30 (May 12 through May 24, 2021) (the most recent week of Phase 3.1).[1]

Q. WHAT DO YOU CONCLUDE ABOUT PENNSYLVANIA EMPLOYMENT INCOME AS IT IS RELATED TO COVID-19?

A. The Census PULSE Survey documents that a large number of Pennsylvania residents report having lost employment income even in the "past four weeks" (i.e., at the time of the survey). Table 1 shows that as recently as Week 30 of the PULSE Survey (May 12 through May 24, 2021), more than 1.6 million Pennsylvania residents (16.5%) reported losing employment income in the past four weeks. The Table shows further that, substantially more than 1.2 million Pennsylvania residents <u>*expect*</u> to lose employment income "in the next 4 weeks." More than one-in-six Pennsylvania residents, in other words, have lost income and an additional one-in-twelve expect to lose income in the next four weeks.

[1] All PULSE Survey data cited in my testimony can be accessed at:https://www.census.gov/programs-surveys/household-pulse-survey/data.html#phase3.1 (last accessed June 2, 2021).

Table 1. Experienced and Expected Loss of Employment Income (Pennsylvania) (PULSE Survey)

	Experienced Loss of Employment Income in Last Four Weeks			
	Week 30			
	Total	Yes	No	% Yes
Total	9,760,505	1,606,120	8,090,145	16.5%
	Expected Loss of Employment Income in next 4 weeks			
	Week 30			
	Total	Yes	No	% Yes
Total	9,760,505	1,247,222	8,432,238	12.8%

On a percentage basis, this loss of employment income was over-represented in the lower income brackets in Pennsylvania. Table 2 shows the proportionate representation of Pennsylvania residents who have experienced a loss of income in the last four weeks. By "proportionate representation," I mean that I first determine the percentage of total population in each income range. I then compare the percentage of population in each income range reporting a loss of employment income. Those income ranges which are over-represented in the income ranges having lost employment income are highlighted in yellow. With the exception of residents with income between $35,000 and $49,999, the income ranges that disproportionately experienced a loss of employment income were those incomes less than $75,000. Persons in the income range of $25,000 to $34,999 were the most over-represented in that population having experienced a loss of employment income. This further supports the conclusion that the economic crisis associated with COVID-19 is not simply a "low-income" issue, but instead reaches beyond those households with income at or below 150% of Poverty Level. Of Pennsylvania residents who have experienced a loss of employment income in the last four weeks, more than 14% fell in that income range even though that income range represented only 8% of the total population reporting data.

Table 2. Loss of Employment Income by Household Income (in the last four weeks)
(Income Range as Percent of Total) (PULSE Survey)
(yellow shade: income ranges disproportionately represented in loss of employment income)

	Week 30	
	Total	Yes
<$25,000	9.3%	11.9%
$25,000 - $34,999	8.3%	14.1%
$35,000 - $49,999	6.9%	6.9%
$50,000 - $74,999	13.3%	15.3%
$75,000 - $99,999	9.3%	7.0%
$100,000 - $149,999	11.1%	5.8%
$150,000 - $199,999	3.6%	2.2%
$200,000 and above	4.6%	0.5%
Sum of those reporting	100%	100%

Based on this data, it is necessary to conclude that while the loss of employment income certainly disproportionately affected the lowest income households, that loss of employment income was not ***exclusively*** a low-income phenomenon.

Q. HOW HAS COVID-19 AFFECTED THE ABILITY OF PENNSYLVANIA RESIDENTS TO PAY THEIR USUAL HOUSEHOLD EXPENSES?

A. Pennsylvania residents have continuing difficulties in paying for their basic living expenses under COVID-19. The Census PULSE survey reports on the "difficulty paying for usual household expenses during the coronavirus pandemic." Table 3 presents the data for Pennsylvania. As this Table shows, the economic conditions for Pennsylvania residents are still dire. In week 30 of the PULSE Survey, 993,000 Pennsylvania residents had a "very difficult" time in paying for usual household expenses in the past seven days. Moreover, the combined total of people reporting that they found it either "very difficult" or "somewhat difficult" to pay for usual household expenses in Week 30 was 24.6%, nearly one-in-four of all Pennsylvania residents.

In contrast, the percentage of Pennsylvania residents reporting that they found it "not at all difficult" to pay for their usual household expenses in the past seven days during the coronavirus pandemic still remained at just over 50% of the total population reporting. Only half of all Pennsylvania residents, in other words, found it "not at all" difficult to pay their usual household expenses, even at the end of May 2021.

Table 3. Difficulty in Paying for Usual Household Expenses in Past 7 Days During the Coronavirus Pandemic (PULSE Survey) (Pennsylvania) (Total = 9,760,505)[2]

Week 30 (in millions)

Not at All	A Little	Somewhat	Very
4.790	2.054	1,248	0.993
52.7%	22.6%	13.7%	10.9%

As with the data on the loss of employment income, the data on difficulties in paying for usual household expenses during the coronavirus pandemic shows a marked difference based on income levels. The data is set forth in Table 4 below. Not surprisingly, the biggest reduction in the percentage having a "very difficult" time in paying for usual household expenses occurs in the income groups with the largest percentage of

[2] Percentage is of those reporting.

population having such difficulties in the first instance. Within the population of households with income less than $25,000, more than one-in-four (28.6%) of households report having a “very difficult” time in paying their bills.

The “very difficult” data, however, does not tell the entire story. Nearly three-fifths of the population with income less than $25,000 report having a “very difficult” or a “somewhat difficult” time (27.9% + 28.6% = 56.6%) in paying for usual household expenses in the past seven days. Problems in the next two income ranges also remain very prevalent. Nearly half (47.1%) of households with income between $25,000 and $34,999 (26.6% + 20.5%) have a “somewhat” or “very” difficult times paying their usual household expenses. 30.7% in the income range of $35,000 to $49,999) report having a “somewhat difficult” or “very difficult” time in paying usual household expenses in the past seven days as of Week 30. Even in the income range as high as $50,000 to $74,999, nearly one-in-five (19.7%) Pennsylvania residents report having either a “somewhat difficult” or a “very difficult” time paying for their usual household expenses.

Table 4. Difficulty in Paying for Usual Household Expenses in Past 7 Days During the Coronavirus Pandemic by Annual Income (PULSE Survey) (Week 30) (Pennsylvania) (Total = 9,760,505)[3]

		Week 30			
		Not at All	A Little	Somewhat	Very
<$25,000	907,637	19.7%	23.8%	27.9%	28.6%
$25-$34,999	813,121	26.5%	26.3%	26.6%	20.5%
$35 - $49,999	678,228	45.2%	24.2%	13.6%	17.1%
$50 - $74,999	1,294,422	56.6%	23.7%	9.9%	9.8%
$75 - $99,999	905,899	60.5%	14.0%	18.8%	6.7%
$100 - $149,999	1,081,575	74.5%	16.5%	3.7%	5.3%
$150 - $199,999	354,392	83.7%	13.1%	3.2%	0.0%
$200,000+	449,135	89.1%	9.9%	0.5%	0.5%

Q. WHAT DO YOU CONCLUDE?

A. Even as the public vaccination against the coronavirus becomes more widespread, the economic crisis caused by the COVID-19 pandemic continues to hit Pennsylvania residents, including Columbia Gas customers, hard. The economic impacts will result in a long-term economic disruption for customers of Columbia Gas.

Q. WHAT IS THE FIRST LONG-TERM ECONOMIC IMPACT OF COVID-19?

A. The resolution of the COVID-19 health crisis will not end the economic crisis facing low-income customers. One analysis by the Center on Poverty and Social Policy at Columbia University projects the longer-term effects of the COVID-19 economic crisis.[4] The

[3] Percentage is of those reporting.

[4] Parolin and Wimer (April 16, 2020). Forecasting Estimates of Poverty During the COVID-19 Crisis: Poverty Rates in the United States Could Reach Highest Levels in Over 50 Year, available at

Columbia University research center forecasted poverty rates under three alternative unemployment scenarios: 10 percent; 20 percent, and 30 percent. The Center assumed that such high levels of unemployment lasted for two different scenarios: (1) one quarter, and (2) one year. The Center uses the "Supplemental Poverty Measure" (SPM), which differs somewhat from the Federal Poverty Level.[5]

The Center began with a projected SPM of 12.4% in February 2020, the lowest recorded poverty rate since 2001. Its projected poverty rates after the onset of the COVID-19 pandemic, however:

> [P]oint to higher poverty rates today. If unemployment rates rise to 10 percent, comparable to the unemployment rate during the peak of the Great Recession, we project that poverty rates would rise to 15 percent. This is approximately the same rate of poverty observed in 2010. (note omitted). If unemployment rates rise to 20 percent, we project a poverty rate of 16.9 percent—the highest rate of poverty since 1967, the first year for which reliable estimates of poverty are available. Finally, if annual unemployment rates rise to 30 percent, we project a poverty rate of 18.9 percent. This would mark the highest rate of poverty over the past 50 years.[6]

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https://www.povertycenter.columbia.edu/news-internal/coronavirus-forecasting-poverty-estimates, (last accessed June 4, 2021).

[5] In simplified terms, the Census Bureau explains that the Supplemental Poverty Measure, "takes into account family resources and expenses not included in the official measure as well as geographic variation. First, it adds the value of in-kind benefits that are available to buy basic goods to cash income. In-kind benefits include nutritional assistance, subsidized housing and home energy assistance. Then it subtracts necessary expenses for critical goods and services not included in the thresholds from resources. Necessary expenses that are subtracted include income taxes, Social Security payroll taxes, child care and other work-related expenses, child support payments to another household, and contributions toward the cost of medical care and health insurance premiums." What is the Supplemental Poverty Measure and How Does it Differ from the Official Measure, available at, https://www.census.gov/newsroom/blogs/random-samplings/2018/09/what_is_the_suppleme.html (last accessed June 4, 2021).

[6] Id., at 4 - 5.

Two observations are appropriate. On the one hand, unemployment in Pennsylvania did not reach the 20% or 30% levels represented by the two upper ranges in this analysis. Accordingly, the 20% and 30% unemployment scenarios are set aside for this discussion. Even with this lowest scenario, the Center stated: "under an optimistic scenario, in which employment rates return to pre-crisis levels during the summer of 2020, annual SPM poverty rates are still projected to reach levels comparable to the Great Recession."[7] On the other hand, employment rates, as we now know, did ***not*** return to the pre-crisis levels in the summer of 2020.

This increase in Poverty is important for purposes of this proceeding because it is not likely to be resolved in the short-term. The long-term danger arises because when people lose their jobs, the long-lasting effects are not just on their income. Moreover, with the COVID-19 pandemic, it is generally recognized that many of the jobs that have been lost will never come back. One recent research paper from the Becker Freidman Institute for Economics at the University of Chicago estimates that between 32% and 42% of COVID-19 induced layoffs will be permanent.[8]

Q. IS THERE A SECOND ECONOMIC IMPACT THAT SHOULD BE CONSIDERED IN THIS PROCEEDING?

A. Yes. Nearly 40% of U.S. households, including nearly all low-wage workers, fall into a category referred to as "liquid asset poor." "Liquid asset poor" is a term-of-art that refers

[7] Forecasting Estimates of Poverty, supra, at 9.

[8] Davis et al. (June 2020). COVID-19 is also a Reallocation Shock, available at: https://bfi.uchicago.edu/wp-content/uploads/BFI_WP_202059.pdf (last accessed June 4, 2021).

to households who lack sufficient liquid assets to replace income in order to subsist at the Poverty Level for three months in the absence of income. According to a Pew Research Center report, "only about one-in-four (23%) [lower income adults] say they have rainy day funds set aside that would cover their expenses for three months in case of an emergency such as job loss, sickness or an economic downturn, compared with 48% of middle-income and 75% of upper-income adults." [9]

As the COVID-19 economic crisis moves into a more prolonged period, the impact of the lack of savings will become increasingly pronounced, with low-income customers, in particular, unable to draw on resources to pay day-to-day bills. A Pew Research Center study published in late September reported that half of all adults who said they had lost a job due to the coronavirus were still unemployed "roughly six months since the coronavirus outbreak sent shockwaves through the U.S. economy."[10] Moreover, according to Pew, even those who did not lose their job, but who nonetheless lost income, were still in bad economic shape. Pew reported:

> Of those who say they personally lost a job, half say they are still unemployed, a third have returned to their old job and 15% are in a different job than before. Lower-income adults who were laid off due to the coronavirus are less likely to be working now than middle- and upper-income

[9] Parker, Horowitz and Brown (April, 2020). About Half of Lower-Income Americans Report Household Job or Wage Loss Due to COVID-19, Pew Research Center: Washington D.C. Available at https://www.pewsocialtrends.org/2020/04/21/about-half-of-lower-income-americans-report-household-job-or-wage-loss-due-to-covid-19/ (last accessed June 4, 2021).

[10] Parker, Minkin and Bennett (September 24, 2020). Economic Fallout from COVID-19 Continues to Hit Lower-Income Americans the Hardest, at 1, Pew Research Center (Washington D.C.). (hereafter COVID-19 Economic Fallout), https://www.pewsocialtrends.org/2020/09/24/economic-fallout-from-covid-19-continues-to-hit-lower-income-americans-the-hardest/ (last accessed June 4, 2021).

> adults who lost their jobs (43% vs. 58%). Adults ages 18 to 29 are less likely than those 30 to 64 to have returned to their previous job.
>
> Even if they didn't lose a job, many workers have had to reduce their hours or take a pay cut due to the economic fallout from the pandemic. About a third of all adults (32%) say this has happened to them or someone in their household, with 21% saying this happened to them personally. Most workers who've experienced this (60%) are earning less now than they were before the coronavirus outbreak, while 34% say they are earning the same now as they were before the outbreak and only 6% say they are earning more.[11]

Pew continues, however, to note that "lower-income adults who lost their jobs because of the coronavirus outbreak are more likely than those with middle or upper incomes to remain unemployed. Some 56% of workers with lower incomes who lost their job because of the coronavirus outbreak say they are currently unemployed, compared with 42% of middle- and upper-income adults."[12]

This long-term job loss is significant because one of the long-term economic implications of the job loss and other loss of income is just now becoming more evident. Economic difficulties, particularly for lower-income households, will prevail for an extended period of time not only because these households have been forced to use their emergency savings, but also because they have been forced to incur substantial debt during the COVID-19 pandemic to date. According to Pew:

> Those affected by coronavirus related job loss or pay cuts are much more likely than those who have not experienced these setbacks to have drawn on additional resources. Fully 46% of adults who say they or someone in their household have either been laid off or taken a pay cut as a result of the

[11] Id., at 5, 7, 8.

[12] Id., at 7 – 8.

> coronavirus outbreak say they have used money from a savings or retirement account to pay their bills, compared with 17% of those who have not experienced these setbacks.[13]

As the COVID-19 economic crisis continues, these households are now running out of savings to draw down. A Bankrate survey found that "of households with income below $50,000, about 44% say their savings has dropped, compared with 27% of those earning above that amount. . ." Bankrate reported that 27% of Americans say that they now have emergency savings that would last less than three months; 20% say their emergency savings would last from three to five months; and 25% say their emergency savings would last six months.[14]

Q. HAVE YOU EXAMINED DATA SPECIFIC TO THE COMMONWEALTH OF PENNSYLVANIA?

A. Yes. The discussion below is based on the U.S. Census Bureau's "Pulse Survey" as I discussed above. As in my discussion above, I examine data from Week 30 (May 12 through May 24, 2021) (from Phase 3.1).

Q. WHAT DO YOU KNOW ABOUT PENNSYLVANIA?

A. The problems posed by consumers being forced to use credit and/or savings to pay household bills during the pandemic can be seen from data specific to Pennsylvania. And they continue through today. According to the Census Bureau's PULSE Survey, in Week

[13] Covid-19 Economic Fallout, supra note 10, at 12.

[14] Survey: Nearly 3 times as many Americans say they have less emergency savings versus more since pandemic, available at https://www.bankrate.com/banking/savings/emergency-savings-survey-2020/ (last accessed June 4, 2021).

30 of the PULSE Survey, households using such resources had substantially greater difficulties in meeting their household needs. While 18.7% of Pennsylvania residents using credit cards or loans, and 22.3% drawing down savings (or selling assets), found it "very difficult" to pay "usual household expenses," only 6.2% using their usual pre-pandemic income sources did so. While 23.3% (money from savings or selling assets) to 14.6% (credit cards or loans) of Pennsylvania residents found it "somewhat difficult" to pay their "usual household expenses," only 13.9% using their normal pre-pandemic incomes sources did so.

In total, one-third of Pennsylvania residents who have been forced to use credit cards or loans (14.6% + 18.7% = 33.3%), and nearly half forced to draw down savings or sell assets (23.3% + 22.3% = 45.6%), found it either "somewhat" or "very" difficult to pay their usual household expenses during the pandemic (Week 30). In contrast, only 19.2% using savings or selling assets found it "not at all difficult" to pay their usual household expenses, compared to 61.0% of those who could use their normal pre-pandemic income sources.

Table 5. Difficulty paying for usual household expenses during the coronavirus pandemic (Pennsylvania) (PULSE Survey) (Week 27)					
Used in last seven days to meet spending needs	Total # Reporting	Not at all difficult	A little difficult	Somewhat difficult	Very difficult
Regular income sources like those used before the pandemic	6,802,372	61.0%	22.4%	10.3%	6.2%
Credit cards or loans	2,249,120	43.5%	23.2%	14.6%	18.7%
Money from savings or selling assets	1,314,349	19.2%	35.2%	23.3%	22.3%
Borrowing from friends or family	6,802,372	61.0%	22.4%	10.3%	6.2%
Money saved from deferred or forgiven payments (to meet spending needs)	121,532	29,840	18,799	30,934	41,959

Q. WHAT DO YOU CONCLUDE?

A. The conclusion to be drawn from this data is that low-wage households are far from achieving any post-pandemic economic stability. Even as the public health crisis associated with COVID-19 is mitigated through widespread vaccination in the coming months, the associated economic crisis will continue. It is that economic crisis far more than the public health crisis that Columbia Gas should address. It is the ongoing economic crisis that will adversely affect the ability-to-pay of Columbia Gas customers.

Q. HAS COLUMBIA GAS TAKEN ANY ACTION TO ADDRESS THE ECONOMIC IMPACTS ASSOCIATED WITH THE COVID-19 PANDEMIC?

A. Yes. On April 24, 2020, Columbia Gas filed a petition with the PUC seeking expedited approval to implement a temporary program funded by using a portion of its residential pipeline penalty and refund proceeds to provide grants to certain residential customers experiencing a reduced income due to the COVID-19 pandemic. The proposed Reduced Income Grant Program (RIGP) was proposed because Columbia anticipated that due to the temporary closure of many businesses throughout the Commonwealth, a subset of customers would experience a temporary reduction in income and become payment-troubled. Columbia asserted that this group would consist of customers who previously had made timely payments and had a good credit history with Columbia. The RIGP, as proposed, would have provided a one-time grant and would conclude no later than December 31, 2020, or when the funding had been exhausted, whichever came first.

Q. WHAT WAS THE COMMISSION'S DISPOSITION OF THE COLUMBIA GAS PROPOSAL TO ADOPT THE PROPOSED RIGP?

A. By an order entered July 16, 2020, the Commission denied the Columbia Gas proposal. More specifically, the Commission objected to redirecting funding from the Company's existing hardship fund to a new program. The Commission found that Columbia had not established the need for the additional program. Nor had Columbia established to the Commission's satisfaction that reducing the otherwise available hardship funds would leave sufficient funds remaining to address expected increased needs at existing income eligibility levels given the impacts of COVID-19. The Commission held that "we do not find it appropriate, nor in the public interest, based on the record herein, to reduce [the] available Hardship Fund program by $400,000 so as to create the RIGP to provide energy assistance at exclusively higher income levels. Accordingly, we deny Columbia Gas's request to do so." (Order, Docket P-2020-3019578, at 23, July 16, 2020).

The Commission did not reject the need for, or the authority of the Company, to establish a short-term emergency relief program. The Commission said that "although we do not find it appropriate to reduce available Hardship Fund program grant funding in order to create the proposed RIGP, Columbia Gas has the option to work with stakeholders. . .to develop a consensus proposal."(Id., at 25).

Q. HOW DOES THE COVID-19 TESTIMONY YOU PRESENT ABOVE RESPOND TO THE COMMISSIONERS' CONCERNS?

A. This base rate proceeding provides an opportunity for Columbia Gas to build a reasonable response to the ongoing economic crisis that has been generated by COVID-19. Having moved to address the underlying health needs, it is now time to implement an Emergency Relief Program (ERP). The testimony above presents a compelling needs assessment in support of an ERP. I have demonstrated above that, through Week 30 of the Census Bureau's PULSE Survey:

- Pennsylvania residents have lost income since the beginning of the COVID-19 pandemic (Table 2), with these losses substantial for households with an annual income up to $100,000;
- Significant numbers of Pennsylvania households report continuing to have a "somewhat" or "very" difficult time paying their usual household expenses (Table 3);
- When higher income households are excluded, the percentage reporting having a "somewhat" or "very" difficult time in paying their usual household expenses significantly increases (Table 4);

Moreover, we know from the data I have presented above that in Week 30 of the PULSE Survey (May 12 through May 24, 2021), significant numbers of Pennsylvania residents have been forced to use credit cards or loans to pay their usual household expenses such as utility bills, and that these residents continue to find it "somewhat difficult" or "very difficult" to pay those usual household expenses. (Table 5). We know that Pennsylvania residents have continued to be forced to use their savings (or to sell assets) to pay their usual household expenses (Table 5 and accompanying text). We know that these savings are running out and that the use of credit card debt has become non-sustainable.

Q. IS THERE ADDITIONAL DATA DEMONSTRATING THAT THE ECONOMIC CRISIS BROUGHT ABOUT BY COVID-19 IS AN ONGOING CRISIS?

A. Yes. The data for Pennsylvania indicates that the economic crisis brought about by COVID-19 is independent of the health crisis. The economic crisis which I discuss in more detail above is continuing through the date on which this Testimony is written.

In my discussion above, I discuss the results from the Census PULSE Survey. The Table below presents the PULSE Survey results starting with the Week 27 and extending through the most recent PULSE Survey results available as of the date of this Testimony (Week 30: data released June 2, 2021).

Table 6. Percent of Households (PA) Having "Very Difficult" Time Paying Usual Household Expenses in COVID-19 Pandemic (Households with Income < $50,000) (Census PULSE Survey)

	Week of PULSE Survey			
Income Range	27	28	29	30
< $25,000	26.9%	34.0%	21.4%	28.6%
$25,000 - $34,999	6.9%	16.6%	19.0%	20.5%
$35,000 - $49,999	5.0%	2.6%	15.3%	17.1%

As can be seen, despite improvements in the response to the underlying health crisis, there has *not* been a continuous improvement in the economic conditions:

- The percentage of households with income below $25,000 having a "very difficult" time was 28.6% in Week 30, compared to 26.9% in Week 27.
- The percentage of households with income between $25,000 and $35,000 having a "very difficult" time was 20.5% in Week 30, compared to 6.9% in Week 27.
- The percentage of households with income between $35,000 and $50,000 having a "very difficult" time was 17.1% in Week 30, compared to 5.0% in Week 27.

If you exclude those households who are well-off, difficulties have increased in recent weeks. The adverse economic impacts first identified by Columbia Gas in its petition to establish an RIGP continue even today.

Q. WHAT DO YOU RECOMMEND?

A. Building on the Columbia Gas RIGP as originally proposed, but without recommending that it be funded through a reduction in otherwise available hardship funds, I recommend that the Company implement an ERP in the context of this rate proceeding. To control costs, I recommend that the Columbia Gas arrearage credits be limited to customers with an unpaid balance of more than 60 days old. In this fashion, Columbia Gas is not providing a grant to someone who has simply happened to miss a payment in the short-term. Rather, Columbia Gas is limiting credits to those who are beginning to demonstrate real payment difficulties. In addition, I recommend the proposed cost control mechanism of limiting arrearage grants to $200 or 25% of the outstanding balance, whichever is more (with the creation of credit balances not being permitted). I recommend the program operate through June 2022, unless by motion of a stakeholder or on the Commission's own motion, it is ended before then.

Finally, I recommend that Columbia Gas carefully track the number of its ERP recipients who subsequently become a CAP participant. A customer who subsequently becomes a CAP participant would, of course, have any arrearages incurred prior to CAP enrollment made subject to arrearage forgiveness. Columbia Gas should be prepared to explain to the Commission and to other stakeholders what proportion of its ERP arrearage credits it would have been required to spend through arrearage forgiveness even without an ERP.

Q. HOW DO YOU PROPOSE COLUMBIA GAS RECOVER THE COSTS OF ITS ERP?

A. While I do not propose a ceiling on participation in the program component providing credits for unpaid balances, I find that the costs of an arrearage grant program, given an estimated participation rate of 30%, which reflects CAP participation rates, would be at or below the $400,000 originally proposed by Columbia for its RIGP. This is calculated by multiplying the average number of accounts 60+ days in arrears for January-March 2021 (the three most recent months available) (3,505) by the expected arrearage credit[15] by an estimated participation rate of 30%.

[15] The expected arrearage credit for accounts 60 – 90 days in arrears would be $200. The expected arrearage credit for accounts 90+ days in arrears would also be $200. These credits are calculated by taking the average arrearage (in dollars) for January through March (2021) and dividing by the average number of accounts in arrears for those three months. The average arrearage for accounts 60 – 120 days in arrears was $476, while the average arrearage for accounts 120+ days in arrears was $574. (OCA-V-11, OCA-V-13).

I recommend that Columbia Gas accrue its ERP costs as a regulatory asset the recovery of which will be determined in its next base rate case. While I recommend deferring the decision on rate recovery to the next base rate case, I recommend that three principles be applied: (1) the rate recovery of ERP costs be treated as other extraordinary expenses that are amortized over a substantial period of time; (2) the deferral of ERP costs be without the recovery of interest pending their recovery; and (3) Columbia Gas be required to provide a complete accounting of ERP participants who subsequently become CAP participants and identify the overlap between arrearage credits and what would have become pre-program arrears.

Q. HOW DOES YOUR PROPOSED ERP RELATE TO CAP?

A. Adoption of the ERP would be a more efficient use of ratepayer dollars than a process of enrolling customers harmed by COVID-19 into CAP. I am a proponent and supporter of Columbia's CAP. CAP, however, is designed to address structural inability-to-pay rather than emergency economic situations caused by this health pandemic. Once a person is enrolled in CAP, that person is entitled to remain on CAP for at least twelve months. According to the Bureau of Consumer Service's annual report on collections performance and universal service program, Columbia's average CAP credit in 2019 was $763. The cost to ratepayers would be this CAP credit plus any arrearage forgiveness earned. To the extent that Columbia can respond to a COVID-19 induced nonpayment through this emergency program, rather than enrolling a customer in CAP, ratepayers will benefit.

Part 2. Proposed Increase in Residential Customer Charge.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my Direct Testimony, I assess the disproportionately adverse impacts that the Company's proposed increase in its residential customer charge will have on low-income customers. Columbia proposes to increase its fixed monthly customer charge from $16.75 to $19.33, an increase of $31 per year. The size of the residential customer charge is important to all residential customers because it is an "unavoidable" fixed monthly charge. The increased customer charge, however, has a particularly adverse impact on low-income customers. Accordingly, I recommend that OCA witness Jerome Mierzwa's residential customer charge proposal be adopted.

A. Harms to Low-Income Customers.

Q. WHY DOES THE COLUMBIA CAP NOT PROTECT LOW-INCOME CUSTOMERS FROM THE HARMS OF THE INCREASED CUSTOMER CHARGE?

A. It is not reasonable to expect CPA to know who all of its low-income customers are. Unless the customer has occasion to have contact with the Company, in circumstances where the customer's income would be an input into decision-making, CPA would not identify someone as being "low-income." Accordingly, CPA has confirmed the low-income status of only some of its customer base. According to CPA, in the most recent month for which it had data, the Company had confirmed the low-income status of 60,196 (OCA-V-5, combining Confirmed Low-Income [36,087) plus CAP [24,109]). This is a decrease from the average number (67,582) of Confirmed Low-Income customers Columbia had identified in 2019 (OCA-V-21, Att. A) and the 68,078 Confirmed Low-Income Customers it had identified in 2020 (OCA-V-21, Att. B). Given that the number of Confirmed Low-Income (CLI) customers Columbia has identified has substantially decreased by 12% just since 2020 (average monthly) (68,078 – 60,196 = 7,882 / 68,078 = 0.12), it is increasingly difficult for low-income customers to be protected from the harms of an increased customer charge.

In its most recent Universal Service and Energy Conservation Plan (USECP), Columbia estimated a total low-income population of 101,375. (USECP, at 33). CPA has, in other words, confirmed the low-income status of less than 60% of its estimated low-income population base (60,196 / 101,375 = 0.59).

Q. AMONGST THOSE CONFIRMED LOW-INCOME CUSTOMERS, PLEASE EXPLAIN WHY THE CPA CUSTOMER ASSISTANCE PROGRAM WILL NOT ADDRESS THE INCREASED UNAFFORDABILITY ATTRIBUTED TO THE INCREASED CUSTOMER CHARGE?

A. CPA'S CAP reaches a very small proportion of its confirmed low-income customer base. According to CPA, the Company's data indicates a CAP participation of 24,075. (OCA-5). CPA further reports that it has 445,391 total residential customers. (OCA-V-5). Using this data, I find that CPA has enrolled 5.4% of its residential customers in CAP.

Moreover, the Company reports, however, that it has an estimated 101,375 low-income customers on its system. CAP, therefore, serves less than 23% (i.e., fewer than one-of-four) of CPA's estimated low-income population. (24,075 / 101,375 = 0.237).

Q. DOES CAP ENROLLMENT PROTECT CUSTOMERS FROM BEING ADVERSELY AFFECTED BY THE INCREASE IN THE FIXED MONTHLY CUSTOMER CHARGE?

A. No. CPA has different aspects to its CAP program: the percentage of income component; the average of past payments component; the percentage of bill component; and the minimum payment component.[16] According to the Company, its enrollment by program component year-over-year for 2019, 2020, and 2021, was as set forth in the Table immediately below.

Table 7. CAP Participation (year-over-year)
By CAP Program Component (May 2019, April 2020, April 2021)
(OCA-V-17)

	May 2019	April 2020	April 2021
Total	19,967	18,731	20,196
Percentage of Income	3,731	3,577	3,818
Average of Payments	2,153	1,504	1,735
% of Bill	12,648	12,167	12,713
Minimum Payment	1,435	1,483	1,930
Percentage in "% of Bill" component	63.3%	65.0%	62.9%
Percentage in "% of income" component	18.7%	19.1%	18.9%

[16] I exclude the Senior Discount component as having virtually no-one enrolled in it.

As can be seen in this Table, more than three out-of-five CPA CAP participants participate in the "Percentage of Bill" program component. Through this CAP design, CAP participants pay a percentage of the bill at standard residential rates. If residential rates increase, in other words, the CAP participant's payment will increase correspondingly. Fewer than one-in-five Columbia CAP participants participate in the Percentage of Income Payment Program (PIPP) component. It is only those PIPP participants who are protected from the harms of an increased customer charge by CAP.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that CPA's CAP program protects a very small percentage of its low-income customer base from the harms of an increased customer charge. Columbia Gas has confirmed the low-income status of a relatively small percentage of its estimated low-income population. Out of those Confirmed Low-Income customers, the Company has enrolled a relatively small percentage in CAP. Out of those CAP participants, very few are enrolled in a CAP program component that would protect the customer against bill increases. As noted above, CAP protects a customer from the harms of the proposed increased customer charge only if the customer participates in the PIPP component of Columbia's CAP. As can be seen, it would be an error to assert that low-income customers will see no adverse impact from the increased fixed customer charge because they are protected by the Columbia Gas CAP program.

Q. WHY IS IT SIGNIFICANT THAT CPA UNDER-ENROLLS ITS CONFIRMED LOW-INCOME CUSTOMER POPULATION INTO ITS CAP PROGRAM?

A. The under-enrollment of the CPA confirmed low-income population into CAP is significant because the Company's confirmed low-income population has substantially greater payment difficulties than does the residential population as a whole. Table 8 sets forth the data from the BCS annual report on universal service programs and collections performance.

Table 8. Average Arrears[17] (CPA)
(2014 – 2019)

	Residential	Confirmed Low-Income
2014	$488.88	$555.06
2015	$540.98	$619.67
2016	$440.53	$529.75
2017	$455.54	$549.70
2018	$507.04	$602.49
2019	$544.31	$651.14

Table 8 shows that the confirmed low-income customers of CPA are substantially more seriously in arrears than are residential customers generally. Indeed, the difference is even greater than shown. The "Residential" class has, as one sub-component, the "Confirmed Low-Income" customers. The higher numbers for the Confirmed Low-Income customers, in other words, will pull the Residential customer numbers upwards. If the comparison was between customers who are Confirmed Low-Income versus those who are ***not*** Confirmed Low-Income, the differences would be even greater.

Table 9 below shows the ratio of the payment difficulties of Confirmed Low-Income customers to Residential customers generally as presented in the annual BCS report. The

[17] BCS (annual). Universal Service Programs and Collections Performance. available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed May 29, 2021).

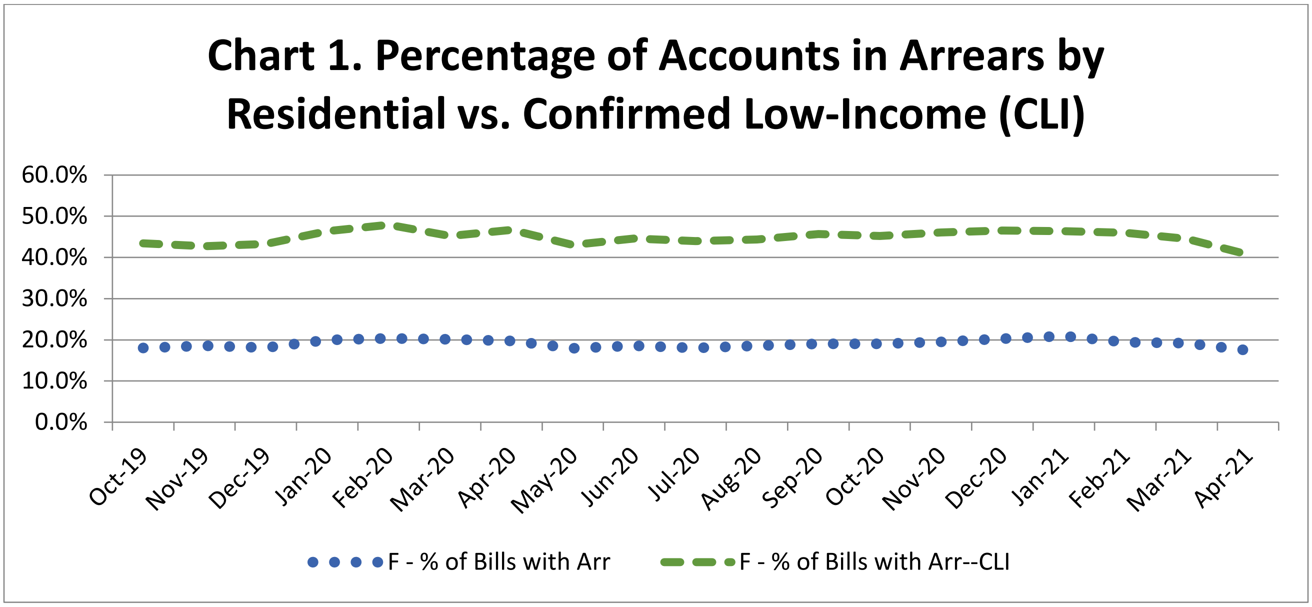
average arrearage for Confirmed Low-Income customers was from 14% to 21% higher than the average arrears for Residential customers for CPA. As can be seen, when Confirmed Low-Income customers are in arrears they are also deeper in arrears than residential customers overall.

Table 9. Ratio Confirmed Low-Income (numerator) to Residential (denominator) Average Arrears of Accounts in Arrears (CPA) (2014 – 2019)

CPA	Average Arrears of Accounts in Arrears (Confirmed Low-Income / Residential)
2014	114%
2015	115%
2016	120%
2017	121%
2018	119%
2019	120%

Q. HAVE YOU HAD OCCASION TO REVIEW OTHER DATA THAT CONCERNS THE PAYMENT DIFFICULTIES EXPERIENCED BY CONFIRMED LOW-INCOME CUSTOMERS?

A. Yes. Chart 1, shown below, is significant in several respects. It demonstrates that Confirmed Low-Income customers are not only deeper in arrears, but also that incidence of arrears in the Confirmed Low-Income population is higher as well. The incidence of arrears in this population is two times (or more) the incidence of arrears in the residential population as a whole. In addition, Chart 1 demonstrates that the while the dollars that are in arrears have increased, the percentage of customers in arrears has remained constant. If Columbia Gas addresses the payment problems with those chronically non-paying (or late paying) customers, there is every reason to believe that the Company will be addressing the underlying dollar problems as well.



Q. HOW DOES THIS ARREARAGE DATA RELATE TO THE PROPOSAL TO INCREASE THE COMPANY'S FIXED MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. This data relates to the Company's fixed monthly residential customer charge because CPA is now proposing to increase the level of the fixed monthly customer charge that cannot be controlled by reducing consumption. Columbia Gas is proposing to substantially increase the unavoidable fixed monthly charge, resulting in a disproportionately high percentage bill increase, precisely to the population of customers who have the most difficulties in paying their bills with which to begin.

Q. WHAT IS THE FINANCIAL IMPACT TO CONFIRMED LOW-INCOME CUSTOMERS?

A. An increase in the fixed customer charge of $2.58 per month represents an increase in the fixed customer charge of $31.00 per year ($2.58/month x 12 months = $30.96). Given the Company's estimated number of low-income customers (101,375: USECP, at 33), this would be an increase in unavoidable annual customer charges of $3.139 million (101,375 x $30.96 = $3,138,570) to Columbia's low-income population.

Q. CAN YOU PUT THE PROPOSED CUSTOMER CHARGE INCREASE INTO SOME CONTEXT?

A. To put this number into context, in program year 2018-2019, CPA customers received $4.655 million in LIHEAP cash grants, while in the 2019-2020 program year, they received $4.533 million in LIHEAP cash grants. (OCA-V-9); in the 2020-2021 program year (to date), Columbia customers have received $4.028 million in LIHEAP cash grants. Just the increase in the fixed customer charge, standing alone, (not the *total* fixed charge, simply the *increase* in the fixed charge), in other words, would represent nearly 70% of the *total* LIHEAP cash grants received by Columbia customers in the 2019-2020 program year, and nearly 80% of the total LIHEAP cash grants received (to date) by Columbia customers thus far in the 2020-2021 program year. Moreover, the amount of funding that Columbia customers have been receiving in LIHEAP cash grants has been declining. From Program Year 2017/2018 through Program Year 2020/2021, LIHEAP grants have declined further each year. (OCA-V-9).

Q. PLEASE SUMMARIZE HOW THE INCREASED CUSTOMER CHARGE WILL HARM LOW-INCOME CUSTOMERS.

A. I conclude that the CPA proposal to increase its customer charge will harm low-income customers in each of the following ways (with each bullet below incorporating every other bullet):

- It will increase both the breadth and depth of arrears, each of which imposes additional utility costs on low-income households along with the social consequences appurtenant thereto.

- It will increase the incidence of service disconnections for nonpayment, along with the increased utility costs on low-income households in addition to social consequences appurtenant thereto.

- It will increase in the incidence of the threat of service disconnections for nonpayment, along with the increased utility costs and social consequences appurtenant thereto.

- It will dilute the efficacy of federal fuel assistance (i.e., LIHEAP) benefits, along with the increased utility costs on low-income households, in addition to the social consequences appurtenant thereto.

- It will increase Home Energy Insecurity, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.[18]

- A reduction in the ability of low-income households to respond to inability-to-pay by reducing usage, and to reduce the consequences of inability-to-pay, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.

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[18] See, Colton, Measuring the Outcomes of Home Energy Assistance Programs through a Home Energy Insecurity Scale, which, by this reference thereto, is incorporated herein as if fully set forth, available at http://fsconline.com/05_FSCLibrary/lib2.html (last accessed June 4, 2021).

B. Low-Incomes and Columbia Gas Residential Usage.

Q. HAVE YOU HAD OCCASION TO EXAMINE COMPANY-SPECIFIC DATA ON THE DISTRIBUTION OF USAGE?

A. Yes. Columbia Gas provided a distribution of usage for its residential customers as a whole, for its Confirmed Low-Income ("CLI") customers, and for its CAP customers. (OCA-V-1). The Company provided data for 18 months (October 2019 through March 2021). It disaggregated data into six usage ranges (which are reflected in the Table immediately below).[19] As can be seen in this Table, when compared to residential customers as a whole, a higher percentage of Confirmed Low-Income customers have very low usage, while a lower percentage of CLI customers have very high usage. In 14 of the 18 months of data, CLI customers had a higher percentage of customers in the lowest usage band than residential customers as a whole (in two months, the percentages were functionally equal). In 15 of the 18 months, CLI customers had a lower percentage of customers falling in the highest usage band than residential customers as a whole) (with the other three months functionally equal). Even in the second highest usage band, CLI customers had a lower percentage of customers (than residential customers as a whole) in 17 of the 18 months.

Since Columbia is a natural gas utility, it is also instructive to examine the data limited to heating months. Of the nine heating months studied (December 2019 – April 2020 + December 2020 – March 2021),[20] Confirmed Low-Income customers had, when compared to residential customers as a whole, proportionately more customers in the

[19] The ranges that were reported were selected by the Company.

[20] Columbia did not report data for April 2021.

lowest usage band in all nine heating months, while they had proportionately fewer customers in the two highest usage bands in eight of the nine heating months (with the ninth month being functionally the same).

Table 10

	<=5 DTH	>10=<20 DTH	>50=<100 DTH	>100 DTH
	Confirmed LI % vs. Residential			
Number of months	18	18	18	18
Comparison (CLI vs. Res)	14 CLI higher pct (2 same)	13 CLI higher pct (1 same)	17 CLI lower pct (1 same)	15 CLI lower pct (3 same)
	Confirmed LI % vs. Residential			
Number of winter months	9	9	9	9
Comparison (CLI vs. Res)	9 CLI higher pct	8 CLI higher pct	8 CLI lower pct (1 same)	8 CLI lower pct (1 same)

Q. IS THIS COLUMBIA GAS DATA CONSISTENT WITH WHAT YOU WOULD EXPECT?

A. Yes. Low-income customers, disproportionately are low-use customers. In making this observation, I note the obvious: that my statement is _not_ that _all_ low-income customers are also low-use. My statement is that low-income customers are disproportionately low-use. The proposed increase in the fixed monthly residential customer charge imposes a disproportionate increase in bills to these low-income, low-use customers.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT LOW-INCOME CUSTOMERS ARE DISPROPORTIONATELY LOW-USE CUSTOMERS.

A. While low-income households tend to have less efficient energy consumption than do residential customers generally on a per square foot of housing basis, because they live in much smaller housing units, they tend also to have lower overall natural gas consumption. The most recent data published by the U.S. Department of Energy (DOE) in its 2015 Residential Energy Consumption Survey (RECS), as presented in Table 11, shows the following for total natural gas usage in the Northeast (RECS, Table CE2.2).[21]

Table 11. Per Household Natural Gas Use by Income (Northeast)
(2015 Residential Energy Consumption Survey) (Table CE2.2)

2009 Annual Household Income	mmBtu	CCF
Less than $20,000	52.0	501
$20,000 to $39,999	63.5	616
$40,000 to $59,000	64.9	630
$60,000 to $79,999	65.9	642
$80,000 to $99,999	80.2	779
$100,000 to $119,999	99.7	972
$120,000 - $139,999	85.7	833
$140,000 or more	80.0	782

It does not matter which natural gas end-use is being examined. At lower income levels, natural gas usage is noticeably lower. The average household data by natural gas end-use, in million BTU, for Northeast households using the end-use (2015 RECS, Table CE4.7) is presented immediately below.

[21] The 2009 RECS data referenced in Table 11 and Table 12 can be accessed at: https://www.eia.gov/consumption/residential/data/2015/ (last accessed May 28, 2021).

Table 12. Natural Gas Consumption by End-Use and Income (mmBtu) (Northeast)
(2015 Residential Energy Consumption Survey) (Table CE4.7)

2009 Annual Household Income	Total	Space Heating	Water Heating
Less than $20,000	52.0	43.2	17.0
$20,000 to $39,999	63.5	49.7	20.6
$40,000 to $59,000	64.8	48.0	17.7
$60,000 to $79,999	65.9	60.8	19.4
$80,000 to $99,999	80.2	61.9	22.5
$100,000 to $119,999	99.7	78.1	23.6
$120,000 to $139,999	85.7	68.8	23.0
$140,000 or more	80.0	66.2	22.4

Q. DOES THE DEPARTMENT OF ENERGY PROVIDE DATA THAT HELPS TO EXPLAIN WHY LOW-INCOME CUSTOMERS TEND ALSO TO BE LOW USE CUSTOMERS?

A. Yes. The RECS data clearly shows that natural gas consumption increases as the size of the housing unit increases. The related housing characteristics support this conclusion. Residents of single family housing units have greater consumption than residents of multi-family housing. Renters have lower consumption than do homeowners. And occupants of homes with more rooms have higher gas consumption than occupants of dwellings with fewer rooms.

It is *not* my testimony, in other words, that because low-income customers in the Northeast have lower natural gas consumption, low-income customers in Pennsylvania also do (since Columbia Gas of Pennsylvania is part of the Northeast). My analysis identifies what factors tend to result in lower natural gas consumption as supported by the

RECS data. I then review the extent to which those factors are, in fact, associated with low-income status in the Columbia Gas service territory.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT COLUMBIA GAS CUSTOMERS ARE DISPROPORTIONATELY LOW-USE CUSTOMERS.

A. In the Columbia Gas service territory, there is a relationship between the presence of low-income households and the housing attributes which the Department of Energy (DOE) has identified, through its Residential Energy Consumption Survey (RECS), as being associated with lower natural gas consumption.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE SIZE OF A HOUSING UNIT AND NATURAL GAS CONSUMPTION?

A. The RECS reports that smaller housing units tend to use less natural gas than do larger housing units. The DOE data is set forth in Table 13 below. As can be seen, as housing units get bigger (in terms of square footage of space), natural gas usage becomes greater as well.

Table 13. Household Site Fuel Consumption in the Northeast Region, Averages, British Thermal Units (Btu) and Hundred Cubic Feet (CCF) (2015 RECS Table CE2.2)

Housing Unit Characteristics and Natural Gas Usage Indicators	Per Household (million Btu)	Per Household (CCF)
Total Square Footage		
Fewer than 1000	28.7	279
1,000 to 1,499	56.2	542
1,500 to 1,999	75.2	724
2,000 to 2,499	89.9	872
2,500 to 2,999	93.9	914
3,000 or more	109.5	1,069

Housing units with fewer than 1,000 square feet have gas usage (in physical units of energy) of 279 CCF. In contrast, housing units with 3,000 or more square feet have natural gas usage of 1,069 CCF. Housing units with between 2,000 and 3,000 square feet are in between (872 to 914 CCF).

Q. IS THERE A RELATIONSHIP BETWEEN LOW-INCOME STATUS AND HOUSING UNIT SIZE IN THE COLUMBIA GAS SERVICE TERRITORY?

A. Yes. The Census Bureau does not directly report data on the size of housing units (in square feet). However, conclusions can be drawn about the size of a housing unit by looking at the number of rooms in the unit, as well as by looking at the number of bedrooms in a housing unit. A housing unit with more rooms is more likely to be "larger" while a housing unit with fewer rooms will be "smaller." Similarly, a housing unit with more bedrooms will be larger while a housing unit with fewer bedrooms will be smaller. The data is set forth in the Figures below.

As the Figure immediately below shows, while 37 zip codes within the three highest deciles of low-income penetration also fall within the three highest deciles of penetrations of smaller housing units (i.e., fewer than three rooms), only 18 zip codes within the three deciles with the smallest percentages of low-income households (Deciles 1 – 3) fall within the three deciles with the highest penetration of smaller housing units (Deciles 8 – 10) (blue-shaded cells). Similarly, 35 of the zip codes with the lowest penetration of small housing units also fall within the deciles with the lowest penetration of low-income population.

		Deciles of Percentage of Small Housing Units (<3 Rooms)	
		3 Lowest	3 Highest
Deciles of Population < 150% FPL	3 Lowest	35	18
	3 Highest	30	37

Figure 1. Population Below 150% FPL vs. Housing Units with <3 Rooms

Even more compelling is the observation that while 12 zip codes with low penetrations of low-income population fall within the three lowest deciles of the smallest numbers of median rooms, 44 zip codes with high percentages of low-income population fall within the three deciles with the lowest percentage of small housing units. Conversely, while 60 zip codes with the smallest percentage of low-income population fall in the three deciles with the largest median number of rooms, only 12 zip codes with high percentages of low-income population also have large housing sizes. Clearly, as the percentage of lower-income households increases in the Columbia Gas service territory, so, too, does the percentage of smaller housing units increase.

		Deciles of Median Number of Rooms	
		3 Lowest	3 Highest
Deciles of Population < 150% FPL	3 Lowest	12	60
	3 Highest	44	12

Figure 2. Population Below 150% FPL vs. Median Number of Rooms

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and discussion presented above, I conclude that low-income households in the Columbia Gas service territory are disproportionately likely to live in homes that consume lower levels of natural gas. As a result, the Columbia Gas proposal to substantially increase its fixed monthly customer charge will disproportionately impose adverse impacts on low-income customers.

Ultimately, based on this discussion, along with my initial discussion of the adverse impacts that will accrue to low-income customers of Columbia Gas, I recommend that the residential customer charge recommended by OCA witness Jerome Mierzwa be adopted.

Part 3. Addressing Low-Income Needs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider the extent to which Columbia Gas is adequately addressing the affordability needs of the Company's low-income customers. In the February 18, 2021 Joint Statement of PUC Commissioner Brown Dutrieuille and Commissioner Sweet in Docket R-2020-3018835, the Commissioners said that "we believe there are fundamental problems with the affordability of Columbia's CAP, and most certainly with its outreach efforts, both of which require greater scrutiny than what was given during the course of litigation in this rate case." Moreover, in the Decision and Order in Columbia's last base rate case, the Commission stated that

> [T]he Company needs to determine whether it has exhausted all grassroots community-based avenues to identify new low-income customers. For example, besides the community-based organizations Columbia already is working with, are there other local organizations it can partner with, such as food banks, schools, Head Start or other preschool programs to implement more fully its outreach strategies. We expect Columbia will address these additional outreach efforts and corresponding results in its upcoming annual Management Audit Progress Reports due in 2021 and 2022.

While the 2021 Management Audit Progress Report is not due until August 2021, it seems appropriate to consider at this point, just weeks before that Progress Report is due, what steps Columbia Gas has taken.

Q. DID COLUMBIA GAS ADDRESS THE CONCERNS EXPRESSED BY COMMISSIONERS REGARDING THE COMPANY'S OUTREACH EFFORTS IN ITS FILING?

A. In the February 18, 2021 Joint Statement of PUC Commissioner Brown Dutrieuille and Commissioner Sweet in Docket R-2020-3018835, those Commissioners said that "we believe there are fundamental problems with the affordability of Columbia's CAP, and most certainly with its outreach efforts, both of which require greater scrutiny than what was given during the course of litigation in this rate case." When asked by OCA where Columbia Gas addressed those concerns, the Company responded:

> The Company specifically addressed the Commissioners[‘] concerns about Columbia Gas outreach efforts in the Witness Davis testimony, Statement 13, in the following sections: Page 19, line 3 through Page 20, line 6; Page 20, line 19 through Page 21, line 5; Page 23, line 15 through Page 24, line 7.

(OCA-V-25). Given this response that the Company relies on those three specific parts of Statement 13, I will limit my review specifically to that testimony.

- At page 19, line 3 through Page 20, line 6, Columbia Gas witness Davis states that the Company is meeting with its Universal Service Advisory Council (USAC) to review existing and planned outreach. However, the fundamental testimony of Ms. Davis mirrors the discovery responses. She seeks to justify the Company's outreach by noting that "its CAP participation rates are not below that of other Pennsylvania utilities." (CPA St. 13, page 19, lines 14-15). She further states that "the Company utilizes a broad range of outreach efforts and opportunities to reach all low income customers." (CPA St. 13, page19, lines 18-19). Those basic arguments have been discussed above.

- At page 20, line 19 through page 21, line 5, Columbia Gas witness Davis mentions improvements to its website, along with an ad campaign "focused on energy efficiency and educating customers on the importance of reducing energy usage. . ." Neither of those are directed toward increasing CAP participation, let alone targeted to the below 50% of Poverty population.

- At page 23, line 15 through page 24, line 7, Columbia Gas witness Davis discusses promotion of its Hardship Fund. This discussion does not address the concerns raised in the Commission's Final Order regarding the

> Revised CAP Policy Statement, nor the Commissioner concerns expressed in the February 28, 2021 public statement regarding developing more robust outreach to increase CAP participation and to reach the below 50% of Poverty population.

In short, having been told by PUC Commissioners in its last base rate case (Docket R-2020-3018835), that "we believe there are fundamental problems with the affordability of Columbia's CAP, and most certainly with its outreach efforts, both of which require greater scrutiny than what was given during the course of litigation in this rate case," rather than addressing those concerns, Columbia Gas discusses programs other than CAP, and reiterates the same information which led the Commission in its Final Order to "question the overall adequacy of consumer education and outreach" (Final Order, supra, at 78); to conclude that "needs are [not] being met"; and to conclude that there is a necessity for utilities "to develop more robust efforts to reach customers. . ."

Q. HAS COLUMBIA GAS UNDERTAKEN ANY NEW STEPS TO IMPROVE ITS GRASSROOTS OUTREACH?

A. Yes. Columbia Gas addressed outreach at the most recent meeting of its Universal Service Advisory Committee (USAC). Moreover, the Company's new social worker has been having one-on-one conversations with USAC members, including the OCA. My recommendations below should not be construed to be in derogation of those positive steps which Columbia Gas is taking to improve its outreach.

A. Effective CAP Outreach.

Q. HOW DID COLUMBIA GAS RESPOND TO THE COMMISSION ORDER?

A. The Commission said that "the Company needs to determine whether it has exhausted all grassroots community-based avenues to identify new low-income customers." While the Company did not respond to this Commission directive in its rate case filing, in response to discovery, Columbia Gas stated in relevant part that "Company personnel do not support the notion that any outreach initiative, grassroots or otherwise could be exhausted as the emergence of new agencies, new opportunities, and new demographics should require a continuous revisit of a plan and tweaking to accommodate these changes. " (OCA-V-49). Nonetheless, the Company provided its "current" list of "community partners." (OCA-V-29). Excluding the office of state Representatives and State Senators, as well as the county offices of the Department of Human Services (which clearly are not "grassroots community-based avenues" as referenced by the Commission), there were 120 "community partners" included on the list. This number is somewhat misleading, however. Consider that The Cornerstone was listed nine (9) different times, while the Housing Authority of Beaver County and Catholic Charities were both listed six times each. The Salvation Army was listed five times, while Housing Opportunities of Beaver County, North Hills Community Outreach/Bellevue, and Northern Tier Community Action Corp. were all listed three times each. On numerous occasions, the Columbia Gas list identified the same organization twice (e.g., Urban League, Holy Family, Head Start and Early Head Start—Beaver County, Center for Community Resources, Blue Prints, Domestic Violence Services of Southwestern PA).

The remaining list, rather than focusing on "grassroots community-based" partners, largely included government agencies (e.g., Children and Youth Services, Veteran's Affairs office) and Housing Authorities.

In contrast, focusing simply on the examples of "grassroots community-based avenues" explicitly mentioned in the Commission order, Columbia Gas identified Head Start programs in only three counties (Beaver, Lawrence, Washington) of the 26 counties in its service territory. Of the 135 school districts in its service territory, Columbia Gas has identified one (1) (Central York School District) as a "community partner." No community food banks were listed, even though Pennsylvania has an organization (Feeding Pennsylvania) which has nine member Food Banks serving 2,700 local partners agencies (such as community and church food pantries, soup kitchens, and emergency shelters) serving all 67 Pennsylvania counties. By itself, the Feeding Pennsylvania organization serves two million persons annually throughout Pennsylvania, yet Columbia Gas does not consider it to be a "community partner" even though the Commission expressly recommended the Company to seek out "food banks."

Q. HAVE YOU HAD OCCASION TO REVIEW DATA TO INDICATE THE EXTENT TO WHICH COLUMBIA GAS IS PROVIDING ADEQUATE CAP OUTREACH TO ITS LOW-INCOME CUSTOMERS?

A. Yes. In reviewing this data, remember what the PUC stated in its Decision and Order in Columbia's most recent rate case. It is not merely the activities that Columbia claims it is pursuing that should be the subject of review. It is the ***results*** of those activities. The

PUC said in its previous rate case decision that "we expect Columbia will address these additional outreach efforts ***<u>and corresponding results</u>***. . ." (emphasis added).

The CAP participation rate I use in performing my review is 24,075, the number of CAP participants reported by Columbia Gas in response to discovery. (OCA-V-5(c)).

First, after matching Columbia Gas CAP participation rates for zip codes with Census data, as I describe above, I compared the number of households receiving either Food Stamps (SNAP) or Cash Public Assistance to the number of customers enrolled in CAP. Within each Zip Code, I reduced the difference by the percentage of households using natural gas as their primary heating fuel.[22] If Columbia Gas enrolled each household who is currently enrolled in Food Stamps/Cash Public Assistance into CAP (estimated to use natural gas for heating), the Company would have an additional 68,266 CAP participants. It is not merely the total that indicates the problem, however. A sample of eight (8) such zip codes is presented in Table 14 below. As can be seen, in these eight (8) Zip Codes in this Table, while there are 13,105 households who have applied for and been found eligible for Food Stamps and/or Cash Assistance,[23] Columbia has enrolled only 184 customers in CAP.[24] In the top six Zip Codes in this table (Zip Code 15122 through Zip Code 15214), while 9,281 households (estimated to heat with natural gas) who have

[22] For example, if there were 100 more Food Stamp/PA recipients than there were CAP participants, but only 53% of all households use natural gas for heating, the Zip Code was counted as 53.

[23] Both such programs have maximum income eligibility lower than the maximum income eligibility for CAP.

[24] It is not possible to determine the extent to which, if at all, the CAP enrollment and the Food Stamp/PA enrollment overlap.

enrolled in Food Stamps and/or Cash Assistance, Columbia has enrolled 26 customers in CAP. Overall, in 286 of the 325 Columbia Gas Zip Codes, there are more Food Stamp/PA recipients (estimated to use gas for heating) than there are CAP participants. In 99 Zip Codes, there are more than 100 more Food Stamp recipients than CAP recipients (representing more than 41,000 households). In 23 Zip Codes, there are more than 500 more Food Stamp recipients than CAP recipients (representing more than 22,700 households).

Table 14. Number of Columbia CAP Participants vs. Number of Food Stamp and/or Cash Public Assistance Participants (by selected Zip Codes)

Zip Code	Food Stamp/PA Recipients (at pct gas heating)	CAP Participants
15122	1,074	0
15219	1,340	0
15601	1,996	0
16001	2,435	1
15205	1,105	12
15214	1,331	13
15001	1,532	57
15212	2,292	101

Similar results can be seen if one examines household receiving Supplemental Security Income (SSI). In Columbia's Zip Codes, there are nearly 17,300 more households (estimated to heat with gas) receiving Supplemental Security Income (SSI) than there are CAP recipients. For example, in the seven Zip Codes identified in Table 15 below, while there are 4,906 SSI recipients, there are 172 CAP participants. In the top four Zip Codes in the Table, while there are 2,997 SSI recipients, there is one (1) CAP participant.

Zip Code	SSI Recipients (at pct gas heating)	CAP Participants
15219	510	0
15122	547	0
15601	1020	0
16001	920	1
15214	511	13
15001	702	57
15212	696	101

Table 15. Number of Columbia CAP Participants vs. Number of SSI Recipients (by selected Zip Codes)

Q. IS THERE ANY SPECIFIC RECOMMENDATION MADE BY THE PUC THAT COLUMBIA GAS HAS NOT PURSUED?

A. Yes. The Commission's Order, previously cited, stated in relevant part: "the Company needs to determine whether it has exhausted all grassroots community-based avenues to identify new low-income customers. For example, besides the community-based organizations Columbia already is working with, are there other local organizations it can partner with, such as. . .schools. . .to implement more fully its outreach strategies?" Columbia has undertaken virtually no effort to work with local school districts in its service territory to promote its universal service programs. Households whose children qualify for Free School Meals would income-qualify for CAP. Households whose children qualify for reduced-cost School Meals would qualify for winter shutoff protections; some children who qualify for reduced-cost School Meals would qualify for CAP.

This is significant in that the federal free and reduced School Meals program (school breakfasts, school lunches) are administered by local school districts. I matched the places that Columbia Gas lists in its tariff to the local school districts serving those communities. I identified all school districts which are served, in whole or part, by Columbia Gas.[25] Then for February 2020 (the month before the COVID-19 pandemic hit), I examined the percentage of school enrollment that was eligible for either the free or reduced school meals program. Of the 135 school districts I reviewed, I found 44 of which had more than 50% of their school enrollment who qualified for either the free school meal program (income at or below 130% of Poverty) or the reduced-cost school meal program (income above 130% of Poverty but at or below 180% of Poverty). Indeed, 22 of the school districts I reviewed had more than 75% of their students who qualified for the free or reduced school meals program. Despite the PUC's suggestion that schools could be an important partner for Columbia Gas in its outreach strategies, however, the Company does not use school districts to engage in universal service outreach.

Q. WHAT DO YOU RECOMMEND?

A. Based on the data and discussion above, I recommend that Columbia be directed to provide a detailed plan addressing how it intends to expand its CAP outreach to expand CAP participation. Consistent with the Commissioners' statement in the recent decision in Columbia's last base rate case, that Plan should include not only a discussion of the

[25] Obviously, school district boundaries and the boundaries of the Columbia Gas service territory are not coterminous.

activities that the Company intends to take, it should also include quantitative outcomes by which the success (or lack thereof) can be measured.

B. Reaching the Population Below 50% of Poverty.

Q. HAVE YOU HAD OCCASION TO EXAMINE WHETHER COLUMBIA GAS APPROPRIATELY TARGETS ITS LOWEST INCOME CUSTOMERS FOR CAP OUTREACH?

A. Yes. The Table below shows the data. In 2018, while 22.4% of all CAP participants had income between 0% and 50% of Poverty, 44.5% of CAP participants had income between 51% and 100% of Poverty. In addition 33.1% of all 2018 CPA CAP participants had income between 101% and 150% of Poverty. The data in 2019 and 2020 shows similar results.

Table 16. CPA CAP Participation by Poverty Level
(2018 – 2020) (BCS Annual Report on Universal Service Programs and Collections Statistics)

	CAP Participation (#s)			CAP Participation (%)		
	0 – 50%	51 – 100%	101 – 150%	0 – 50%	51 – 100%	101 – 150%
2018	5,426	10,772	8,012	22.4%	44.5%	33.1%
2019	5,297	10,539	7,715	22.5%	44.7%	32.8%
2020[26]	5,397	10,385	7,497	23.2%	44.6%	32.2%

This data shows that CPA has an under-representation of customers in the lowest and highest income brackets, while having a substantial over-representation of customers in the middle income bracket. According to the 2019 Census, for the zip codes which CPA

[26] Data reported to BCS (OCA-V-21). The BCS 2020 report has not yet been published.

identified as comprising its service territory, the disaggregation of population by Poverty Level within the CPA service territory was:

- 27.3% of the population with income less than 150% of Poverty had income less than 50% of Poverty;
- 32.7% of the population with income less than 150% of Poverty had income between 50% and 100% of Poverty; and
- 40.0% of the population with income less than 150% of Poverty had income between 100% and 150% of Poverty.

The under-representation of the lowest income range (i.e., below 50% of Poverty) is of particular concern. Because of their low-income, these customers are most likely to have natural gas bills that represent a high percentage of income (i.e., what is known as a "bill burden" or bill as a percentage of income). They are, accordingly, more likely to have the payment troubles that I have identified above. These high burdens are the problem addressed by enrollment in CAP. The customers in this lowest income range, however, are not enrolling in the Company's CAP in a percentage which reflects their percentage in the total population.

Q. HOW MIGHT COLUMBIA GAS TARGET OUTREACH TO ITS LOWEST INCOME CUSTOMERS?

A. Columbia Gas could reasonably target outreach to the geographic areas which have the largest percentage of population with income at or below 50% of Poverty. Of the 325 Columbia Gas Zip Codes for which I have Census data, for example, if Columbia targeted outreach to the 20 with the highest percentages of population having income less than 50% of Poverty, it would reach 42% of the total population with income that low. If it targeted the 25 zip codes with the highest percentage, it would reach nearly half (47.2%) of the population with the lowest income.

Columbia Gas could reasonably target outreach to the geographic areas which have the largest populations of customers with income sources associated with the lowest levels of income. Consider, for example, Supplemental Security Income (SSI). In 2020, the maximum SSI benefit was $783, or 74% of the Federal Poverty Level. The average SSI benefit, however, was only $446. If one compares the 25 Columbia Gas Zip Codes with the highest numbers of SSI recipients to the 25 Zip Codes with the highest percentage of population with income less than 50% of Poverty, there is an overlap of 20 (i.e., only five zip codes have large numbers of SSI recipients but do not also have the highest percentage of population with income below 50% of Poverty).

Columbia Gas could reasonably target outreach to geographic areas which have the largest populations receiving Food Stamps/Public Assistance. If one compares the 25 Zip Codes with the largest Food Stamp/Public Assistance populations, there is an overlap of 19 with the Zip Codes with the higher percentage of population with income less than 50% of Poverty (i.e., only six zip codes have large numbers of Food Stamp/Public Assistance recipients but do not also have the highest percentage of population with income below 50% of Poverty).

Indeed, as Table 17 below shows, 18 Columbia Gas Zip Codes fall in the top 25 of *__all three__* of these low-income metrics.

In comparison, when I compared the CAP participation rates (i.e., CAP participants as percentage of residential customers) by Zip Code to the 25 Zip Codes with the largest percentage of population with annual income at or below 50% of Poverty Level, I found an overlap of only three Zip Codes. In sum, the comparisons are as follows:

Table 17. Number of Zip Codes Metrics for CAP Outreach Targeting (2019)

25 Zip Codes with Highest Pct of <50% FPL Population	ALSO with 25 Highest No. SSI Recipients	ALSO with 25 Highest No. FS/PA Recipients	In Highest 25 of All 3 (<50 FPL, SSI, FS/PA)	25 with Highest Pct <50% FPL ALSO with 25 Highest No. CAP Participants
25	20	19	18	3

Q. WHAT IS THE SIGNIFICANCE OF THIS OVERLAP IN LOW-INCOME POPULATION?

A. If Columbia Gas were to enroll, in the 25 Zip Codes with the highest percentage of population with annual incomes below 50% of Poverty its customer population at the same rate as Cash Public Assistance/Food Stamps, it would enroll an additional 17,065 CAP participants. Remember, this does not involve enrolling *__everyone__* in those Zip Codes. It simply involves enrolling at the same rate as Cash Public Assistance/Food Stamps. In contrast, if Columbia Gas targeted outreach and intake to the 18 Zip Codes which have the highest percentage of population with annual income below 50% of Poverty *__and__* the highest number of SSI recipients *__and__* the highest number of Cash Public Assistance/Food Stamp recipients, the Company would enroll an additional 13,778 CAP participants.

Q. IS THERE ANY OTHER WAY TO TARGET OUTREACH IN THE COLUMBIA GAS SERVICE TERRITORY?

A. In a different way, Columbia Gas could target outreach to geographic areas which have the lowest average First Quintile (Q1) incomes.[27] If Columbia Gas examined the 25 Zip Codes with the lowest average first quintile income, it would find that:

- The average annual Q1 income was between $5,000 and $7,500 in seven of those Zip Codes;
- The average annual Q1 income was more than $7,500 and less than $9,000 in seven more of those Zip Codes; and
- The average annual Q1 income was more than $9,000 and less than $10,000 in ten of those Zip Codes.

In only one of the 25 Zip Codes with the lowest average Q1 income, in other words, was the average Q1 income greater than $10,000 ($10,230). If Columbia Gas targeted outreach to the 25 Zip Codes with the lowest average Q1 incomes, that would be reaching areas of the service territory with extremely low incomes.

Q. WHY IS IT IMPORTANT FOR CPA TO TARGET OUTREACH TO ITS POPULATION WITH INCOME AT OR BELOW 50% OF POVERTY LEVEL?

A. There are two responses to this question. First, it is important for CPA to target outreach to its population with income at or below 50% of Poverty Level because the Commission

[27] The Census Bureau rank-orders all households in a geographic area by household income, from lowest to highest. The Census Bureau then divides this ordering into five equal parts, each part which is called a “quintile.” The “First Quintile” (often called the “lowest Quintile”) is, therefore, that one-fifth of the population with the lowest incomes.

has directed utilities to do so. In its Final Order adopting the Revised CAP Policy Statement in 2019, the PUC stated quite explicitly that:

> While utilities have flexibility as to the contents of their plans, the plans should reflect focused consumer education and outreach efforts, tailored to the demographics of their individual service territories, spanning the duration of the universal service plan period. <u>*In particular, these plans should identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG.*</u>

Final Order, at 79, Docket No M-2019-3012599 (emphasis added). In addition, people with low incomes and high energy burdens can most benefit from Columbia Gas rate assistance.

Q. HOW DOES COLUMBIA CURRENTLY ENGAGE IN TARGETING CUSTOMERS WITH INCOME AT OR BELOW 50% OF POVERTY LEVEL?

A. Columbia Gas has not made specific efforts to comply with the PUC directive that utilities "in particular" should "identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG." In response to a question from OCA for samples of "targeted outreach," for example, Columbia specifically acknowledged that it "does target specific groups on occasion but also finds value in promoting on a larger scale to encompass many targeted audiences at one time." (OCA-V-29). When asked to provide all criteria used to target outreach, Columbia stated that it targeted customers who were past-due, those who "called the Company and identified themselves as low-income," those receiving a LIHEAP grant in the past, those with income between 150% and 250% of Poverty, and senior and veterans. (OCA-V-30). Efforts to reach those customers with income below 50% of Poverty were not identified. In fact, Columbia Gas stated that “many of the activities were sent to many people of different backgrounds to cover all bases. . .” (Id.) When asked for a “detailed explanation” of how Columbia Gas complied with the Commission directive to “in particular. . .identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG,” Columbia responded simply that it “promotes outreach to ***all*** low income customers using a variety of channels.” (OCA-V-35) (emphasis added). Rather than seeking to target the “below 50% of FPIG” population, as directed by the Commission, Columbia directs its outreach to “eligible customers” as well as to “lower income customers.” (Id.)

Q. HOW DOES COLUMBIA MEASURE THE OUTCOMES OF ANY EFFORT TO REACH THE BELOW 50% OF POVERTY POPULATION?

A. As discussed above, contrary to the Commission’s 2019 directive, Columbia Gas does not make any “particular” effort to “educate and enroll” customers with income at or below 50% of the Poverty Level. Moreover, when OCA requested Columbia Gas to provide “all metrics. . .through which Columbia Gas measures the outcomes of its. . .outreach to reach customers with annual income at or below 50% of Poverty Level,” Columbia Gas did not respond. (OCA-V-41(d)). Rather, it provide a generalized response saying it reviews its outreach strategy “identifying new opportunities and prior successful outreach initiatives to encourage ***all*** eligible customers to enroll in ***all*** programs.” (OCA-V-41). It appears to measure “success” by examining “data from all Pennsylvania utilities to determine if the Company’s participation rates are similar or different from other utilities.” (Id.) To measure success by whether Columbia Gas performance is “similar to or different from other utilities,” however, simply ignores the PUC’s findings that:

- “While there is no specific regulatory mandate that each utility must enroll a certain percentage of low-income households in CAP, the near uniform disparity between the total number of potential income-qualified households and those actually receiving assistance calls into question the overall adequacy of consumer education and outreach.” (Final Order, supra, at 78).

- “This fact pattern does not convince us that needs are being met, but rather it illuminates the need for increased awareness. We have noted in various USECP proceedings the necessity for utilities to develop more robust efforts to reach customers, particularly the very marginal, for enrollment in universal service programs.” (Id.)

The Commission has, in other words, specifically found that the existing performance of other utilities “calls into question the adequacy” of outreach; that existing performance “does not convince us that needs are being met”; and that existing performance demonstrates “the necessity for utilities to develop more robust efforts to reach customers.” And yet, Columbia Gas continues to measure its success against that very performance that has been criticized by the Commission.

Q. DOES YOUR TESTIMONY REGARDING CAP OUTREACH AND THE COLLECTION OUTCOMES FOR LOW-INCOME CUSTOMERS RELATE TO A COLUMBIA REQUEST FOR A MANAGEMENT PERFORMANCE ADDER TO ITS RETURN ON EQUITY?

A. No. Columbia Gas presented no issue to address regarding management performance. Columbia witness Mark Kempic (CPA St. 1) talks about the Company’s management performance. When asked “is the Company seeking a rate of return adjustment for management effectiveness in this proceeding," Mr. Kempic replied "No. . .Columbia has opted not to seek an adjustment in this proceeding in light of the COVID-19 pandemic." (Columbia Gas St. 1, at 22).

C. Improving CAP Recertification.

Q. IS THERE ANOTHER IMPROVEMENT THAT COLUMBIA GAS SHOULD PURSUE IN ADDRESSING CAP ENROLLMENT ISSUES?

A. Yes. In addition to the enrollment issues with Columbia's CAP program I identify above, even within its CAP population, a substantial number of CAP participants are removed from CAP due to the failure to recertify. Columbia has identified this high rate of a failure to recertify as a problem for many years, and has failed to remedy the problem. In the Company's most recent evaluation of its universal service programs (OCA-V-22) (hereafter Universal Service Program Evaluation, "USP Evaluation"), Columbia's evaluator noted that "Failed to Recertify was one of the top reasons that customers were removed from CAP in 2016. Approximately 11% (2,435) of the total CAP participants year-end December were removed for failure to recertify income." (USP Evaluation, at Finding CAP-11, OCA-V-22, at 36). The problem, however, is more substantial than noted at this point of the USP Evaluation. Not all CAP participants are required to recertify every year. The USP Evaluation went on to state: "Of the 8,721 customers required to recertify, 2,435 or <u>*28% did not recertify. This continues to be an ongoing issue*</u>." (OCA-V-22, at 42) (emphasis added).

The problem continues through today. From January 2019 through March 2021, 13,945 low-income customers exited the Columbia Gas CAP. Fewer than 10% (9.7%) of those exits were due to a customer being found to be over-income. Only 7.4% were removed for nonpayment. In contrast, more than one-in-three (35.9%) (5,001 of 13,945) were removed due to a failure to re-verify their income. An additional 40.5% (5,655 of 13,945) were removed when they changed residences. (OCA-V-16). Pursuant to the PUC's CAP Policy Statement, however, when a customer changes residences, unless they move out of the Columbia Gas service territory, their CAP participation status is supposed to move with them without need for further action by the customer. Columbia does not indicate the extent to which CAP participants who have been removed from CAP for having moved had, in fact, moved out of the Columbia Gas service territory. In total, however, nearly 11,000 (10,656) of the roughly 14,000 (13,945), or 76.4%, CAP participants who "exited" the program did so for reasons other than whether they were found to be no longer income-eligible. For a company with an average participation of fewer than 23,000 customers since October 2019 (OCA-05-15), however, to lose 10,656 participants due to mobility or a failure to recertify is a major shortcoming in the Columbia Gas CAP. And, it is a shortcoming that was identified by the Company's own program evaluation in September 2017, nearly four years ago.

For purposes here, however, in assessing whether CAP protects the Company's low-income population from the harms of Columbia's proposed substantial increase in its residential customer charge, the Commission should recognize that Columbia has lost nearly half of its average CAP participant population (10,656 of 22,886, or 46.6%) over the last two years due to reasons having nothing to do with the ongoing income eligibility of CAP participants.

The Commission should direct Columbia Gas to develop remedies for its exits relating to failure to recertify and due to customer mobility. The Company should be specifically directed to report back to the Commission on the number of CAP participants who were removed from CAP due to “moved” who nonetheless remained within the Columbia Gas service territory. Those CAP participants should be reinstated to CAP without further action on the part of the customer. In addition, the Company should be directed to report to the Bureau of Consumer Services the affirmative steps it will take to reduce the percentage of exits attributable to a failure to recertify.

Part 4. Allocation of Universal Service Costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. Given the PUC’s recent decision in Columbia 2020, the PUC’s acceptance of the Peak and Average cost-allocation method as discussed in OCA witness Jerome Mierzwa’s testimony, and the facts I have presented above that support the conclusion that there will be a slow recovery from COVID impacts, I am not advancing any position on universal service cost allocation in this case at this time. I recommend that the issue of how to allocate universal service costs be deferred to a future rate case.

Part 5. CAP Cost Recovery.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I identify a problem with the administrative costs incurred by Columbia Gas in the ongoing implementation of its CAP program. According to Columbia Gas, it incurred:

- CAP administrative costs of $724,643 in 2019 (OCA-V-21, Attachment A, at 5); and
- CAP administrative costs of $726,617 in 2020 (OCA-V-21, Attachment B, at 5).

The Company's universal service data reported to the Bureau of Consumer Services (OCA-V-21, Attachments A and B) do not breakdown CAP administrative costs into its component parts. However, the Company's USP Evaluation (OCA-V-22, previously cited) provides the "Administrative Costs Detail" for 2014 through 2016. As can be seen in the Table immediately below, the Company's USP Evaluation notes that, in 2016, 27.5% of its CAP administrative fees were directed toward "outside services"; 25.6% of its CAP administrative fees were directed toward "application fees"; and 40.0% of its CAP administrative fees were directed toward "Call Center Costs."

Table 18. Administrative Costs Detail USP Evaluation (Table 23) (OCA-05-022, at 47)			
	2016	2015	2014
Labor	$67,118	$66,291	$65,076
Materials and Supplies	$594	$595	$291
Outside Services	$282,132	$253,251	$274,743
Employee Expenses	$3,328	$4,154	$3,410
Application Fees	$262,766	$238,434	$231,296
Call Center Costs	$411,315	$478,795	$503,048
Total	**$1,027,252**	**$1,041,519**	**$1,077,864**

The Company's claim that its CAP administrative costs not only remained constant in 2020, but actually *increased*, during the COVID-19 pandemic, is not reasonable. During the COVID-19 pandemic, many (if not most) offices were not open to the public. Moreover, the PUC placed restrictions on most utility collection activities. Columbia Gas notes that it did not require CAP participants to go through the administrative process of re-verifying income in 2020. Moreover, we know that:

- As to "outside services," the CAP enrollment through "community-based organizations" declined by nearly 40% from 2019 (6,828) to 2020 (4,209) (OCA-V-21, Attachments A and B, at 6);
- As to "Call Center Costs," the CAP enrollment through the "distribution company" declined from 1,637 in 2019 to 699 in 2020, a drop of nearly 60% (OCA-V-21, Attachments A and B, at 6);
- Total CAP intake declined from 8,465 (2019) to 4,908 (2020), a drop of more than 40%. (OCA-V-21, Attachments A and B, at 6)

- The total number of CAP nonpayment disconnections were from 733 in May through November 2019 to zero (0) in May through November 2020. (OCA-V-17, Attachment A).
- As to "Call Center Costs," the average number of "full and complete" CAP payments went from 13,610 for May 2019 through April 2020, to an average of 14,075 from May 2020 through March 2021 (April 2021 data not available). (OCA-V-17).

Q. DOES COLUMBIA GAS CLAIM CAP ADMINISTRATIVE FEES AS PART OF ITS CAP COST RECOVERY IN THIS PROCEEDING?

A. Yes. While the USP Rider does not affect the base rates set in this proceeding, Columbia proposes a specific USP Rider charge based on historic experience. That proposed charge would include historic levels of administrative costs. Those CAP administrative costs have not been supported. Indeed, the data above would indicate that using historic levels of CAP administrative costs would be inappropriate. I recommend that Columbia Gas be required to reduce its USP Rider charge to reflect reduced CAP administrative costs in 2020.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appendix A:

Abbreviated Colton Vitae

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA

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EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

PROFESSIONAL AFFILIATIONS:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator:	Belmont Affordable Shelter Fund (BASF)
Past Chair:	Belmont Solar Initiative Oversight Committee
Past Member:	City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair:	Belmont Energy Committee
Member:	Massachusetts Municipal Energy Group (Mass Municipal Association)

Past Chair:	Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Member:	Board of Directors, Belmont Housing Trust, Inc.
Past Chair:	Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member:	Belmont (MA) Energy and Facilities Work Group
Past Member:	Belmont (MA) Uplands Advisory Committee
Past Member:	Advisory Board: Fair Housing Center of Greater Boston.
Past Chair:	Fair Housing Committee, Town of Belmont (MA)
Past Member:	Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member:	Board of Directors, Vermont Energy Investment Corporation.
Past Member:	Board of Directors, National Fuel Funds Network
Past Member:	Board of Directors, Affordable Comfort, Inc. (ACI)
Past Member:	National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member:	Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member:	ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member:	National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member:	National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

BOOKS

Colton, *et al.*, ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

BOOK CHAPTERS

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

JOURNAL PUBLICATIONS

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

TECHNICAL REPORTS

200 technical reports for public-sector and private-sector clients (list available upon request)

JURISDICTIONS IN WHICH EXPERT WITNESS PROVIDED

1. Maine
2. New Hampshire
3. Vermont
4. Massachusetts
5. Massachusetts
6. Rhode Island
7. Connecticut
8. New Jersey
9. Maryland
10. Pennsylvania
11. Washington D.C.
12. Virginia
13. North Carolina
14. South Carolina
15. Florida (Federal Court)
16. Alabama
17. Mississippi
18. Tennessee
19. Kentucky
20. Ohio
21. Indiana
22. Michigan
23. Wisconsin
24. Illinois
25. Minnesota
26. Iowa
27. Missouri
28. Arkansas
29. Texas (Federal Court)
30. South Dakota
31. North Dakota
32. Montana
33. Colorado
34. New Mexico
35. Arizona
36. Utah
37. Idaho
38. Nevada
39. Washington
40. Oregon
41. California
42. Hawaii

Canadian Provinces

1. Nova Scotia
2. Ontario
3. Manitoba
4. British Columbia

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Direct Testimony, OCA Statement 4, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 16, 2021
*311187

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement No. 4R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania	:	

Rebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4R

July 14, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Harry Geller (CAUSE-PA St. 1) regarding modification of the percentage of income burdens to be used in the Columbia Gas of Pennsylvania (Columbia or CPA) Universal Service and Energy Conservation Plan (USECP).

Q. PLEASE EXPLAIN THE RECOMMENDATION IN MR. GELLER'S DIRECT TESTIMONY THAT YOU ADDRESS IN THIS PART?

A. Mr. Geller asserts in his Direct Testimony that CAP rates should be adjusted now, in the context of this proceeding, to ensure that CAP customers are receiving a just and reasonable rate. (CAUSE-PA St. 1, at 22). Mr. Geller's reference to "CAP Rates" is a reference to the percentage of income burdens that underlie CAP bills. I recommend that this proposal be deferred to Columbia's next Universal Service and Energy Conservation

Program (USECP) proceeding.[1] This was the decision of the PUC in the Columbia Gas 2020 base rate decision (R-2020-3018835, Decision and Order, at 161 ["we find that issues related to Columbia's energy burden levels are more properly considered in the context of the Company's next USECP filing. We agree with Columbia and the OCA that the energy burdens of customers on PIP Plans should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs."]). The Commission reached a similar conclusion in the recent PECO (gas) base rate decision (R-2020-3018929, Opinion and Order, Non-Proprietary Version). In that PECO decision, the Commission stated:

> [W]e will not consider CAUSE-PA's proposals relating to PECO's energy burdens, PECO's CAP, and other universal service program issues within the context of this base rate proceeding. We agree with the ALJ that CAUSE-PA's proposals are more properly considered in the ongoing 2019-2024 USECP proceeding. This determination is consistent with the language in the *Final CAP Policy Statement Order*, at 60, 106, and the *February 2020 Reconsideration Order* at 10-11, which provide that energy burden levels and CAP credit issues should be addressed in a public utility's USECP proceeding. . .
>
> We addressed similar issues in *Columbia Gas*, finding that issues related to Columbia Gas's energy burden levels were more properly considered in the context of the Company's next USECP filing. We concluded that energy burdens should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs.

[1] Columbia's most recent USECP was approved in January 2020. Columbia Gas of Pennsylvania, Universal Service and Energy Conservation Plan for 2019 through 2023, Docket No. M-2018-2645401 (January 16, 2020). According to the Commission's most recent scheduling order, Columbia's next USECP should be filed on April 1, 2023. Order, Universal Service and Energy Conservation Plan (USECP) Filing Schedule and Independent Evaluation Filing Schedule, Docket No. M-2019-3012601, at 12 (October 3, 2019).

(Id., at 195).

Q. IS THERE A SECOND REASON TO DEFER THIS ISSUE TO CPA'S NEXT USECP PROCEEDING?

A. While Mr. Geller's testimony focuses on the impact of the revised energy burdens on CAP participants, his testimony does not address the impact of the revised energy burdens on other ratepayers not participating in CAP who may have difficulty paying their home energy bills.

The costs of universal service are borne by all non-participating residential customers. Many of those residential customers are low-income, as defined by the Commission, who are eligible for, but do not participate in, the Company's CAP. One reason an income-eligible customer may not participate in Columbia's CAP, for example, would be that the Company has simply not identified that customer as being income-eligible. According to the most recent (2019) Bureau of Consumer Services (BCS) annual report on Universal Service Programs and Collections Performance,[2] for example, while CPA had 23,551 CAP participants in 2019 (page 51), it had 97,268 estimated low-income customers (page 7). Those low-income customers (i.e., customers with income less than 150% of Poverty) who do not participate in CAP pay for the cost of providing benefits to those low-income customers who do participate in CAP.

[2] BCS (annual). Universal Service Programs and Collections Performance. Available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed July 5, 2021).

In addition to these customers who are eligible for, but who do not participate in CAP, there are those customers whose income is higher than 150% of Poverty but lower than a self-sufficiency standard. Customers in this group are those customers who do not have income sufficiently low to be eligible for CAP, but who also do not have income sufficiently high to meet their day-to-day needs. The group of customers having income in this range can be considered in light of Pennsylvania's Self-Sufficiency Standard.

The data on Pennsylvania's self-sufficiency standard in the Columbia Gas counties[3] demonstrates that customers may not be "low-income" as per the PUC's definition, but still may have insufficient household resources to consistently pay their daily expenses. I consider the 22 counties which CPA lists in its Tariff as comprising (in whole or part) its service territory.

In this assessment, I consider the self-sufficiency incomes, limited to three-person households, for these Columbia counties. There are fifteen different potential family configurations for a three-person household. For example, there could be a single parent with two infants, or a single parent with an infant and a teenager, or two parents with a teenager. Each family configuration needs a different income to meet self-sufficiency. In the CPA service territory, of the 330 possible incomes for three-person households (22 counties x 15 configurations for a 3-person household), 107 exceed 150% of income (100% of income for three-person household = $21,960 x 150% = $32,940) but are less than 200% of Poverty ($21,960 x 200% = $43,920). An additional 147 exceed 200% of

[3] http://www.selfsufficiencystandard.org/pennsylvania (last accessed July 5, 2021).

Poverty, but are less than 250% of Poverty ($21,960 x 250% = $54,900). Of the remaining, 34 exceed 250% of Poverty, but are less than 280% ($21,960 x 280% = $61,488). As can be seen, a significant number of 3-person self-sufficiency incomes in the CPA counties fall between 150% and 280% of Poverty (288 of 330). As I discuss above, therefore, there is a substantial population who falls within this group of concern (i.e., those who are below a Self-Sufficient income but above the CAP income eligibility line).

In sum, I conclude that there is no single population of income-challenged customers served by Columbia Gas. As always, the provision of assistance by Columbia Gas to CAP participants must simply be balanced against the obligation of income-eligible non-participants, as well as the obligation of those whose income exceeds CAP eligibility but are below a standard of self-sufficiency, to pay the costs of such assistance.

Q. WHAT ARE COLUMBIA'S CAP COSTS?

A. If the Commission approves a decrease to the energy burdens, it would be necessary to examine other aspects of the program to ensure that costs are controlled and that the program remains as cost-effective as possible. The costs of Columbia Gas's CAP are again beginning to increase. After some cost moderation in 2010 through 2013, CAP costs are again becoming higher. While the current CAP costs do not reach the 2009 spike, they are back to the same basic levels experienced in 2005 through 2008.

Table 1. Gross CAP Costs by Year: Columbia Gas (2005 – 2019) (BCS annual Report on Universal Service Programs and Collections Performance)					
2005	$22,941,655	2010	$18,260,343	2015	$18,204,869
2006	$25,788,593	2011	$18,141,003	2016	$13,544,667
2007	$23,214,621	2012	$8,167,912	2017	$19,668,704
2008	$24,358,427	2013	$13,272,158	2018	$22,396,085
2009	$28,084,379	2014	$18,237,407	2019	$20,532,606

As I explain in more detail in my Direct Testimony regarding the historic allocation of universal service costs exclusively to the residential class, I remain concerned with CAP cost increases that are flowed through automatically exclusively to residential customers through the universal service charge.

For the reasons set forth below, the Commission should not approve the proposed changes to the energy burdens in this proceeding, particularly in light of the current financial impact of COVID-19 on residential customers who must bear the increased costs of these changes. Asking residential customers to assume even greater costs during this difficult economic time would further strain affordability for the many residential customers who do not qualify for CAP or who do not participate in CAP.

Q. PLEASE DESCRIBE YOUR AFFORDABILITY CONCERNS ASSOCIATED WITH COVID-19.

A. In my Direct Testimony, I outlined in detail the basis for concluding that the economic and financial circumstances of customers remains tenuous and likely will be for some time to come. I appreciate the need for CAP at this critical time. As I outline in my Direct Testimony, the focus of Columbia Gas should be on enrolling customers who are income-eligible. A particular focus should be on enrollment of customers whose income is less than 50% of Poverty Level. That focus was identified in the Commission's Revised CAP Policy Statement.

Q. IS THERE A THIRD REASON THE ISSUE OF CAP BURDENS SHOULD BE DEFERRED TO COLUMBIA'S USECP PROCEEDING?

A. Yes. If the Commission determines that the energy burdens proposed by Mr. Geller should be approved, the Company should be required to implement additional cost control measures as discussed below. Examples of cost control measures that perhaps should be considered include (but may not be limited to):

- limiting the annual increases in CAP costs flowed through the universal service charge;

- increasing the minimum payment;

- extending the length of time for arrearage forgiveness; capping the amount of arrearage forgiveness charged to ratepayers; decreasing overall administrative costs;

- revisiting and adjusting maximum CAP credits;

- allocating Low Income Usage Reduction Program resources (LIURP) to reduce high user bills; and

- re-examining the CAP participation of the Department of Housing and Urban Development (HUD) tenants who receive federal dollars designed to pay their *entire* utility bills (in the absence of CAP).

The reasonableness of each such possible cost control measure would depend on the particular facts presented in a USECP proceeding.

Q. WHAT DO YOU CONCLUDE?

A. Based on the discussion above, I conclude that a base rate case is not the appropriate proceeding in which to determine whether CAP burdens should be revised. This base rate case does not provide the evidentiary record upon which to formulate the entire range of decisions that should accompany a decision on whether or not to reduce CAP burdens. The decision to reduce CAP burdens is not a decision that can stand alone. To the extent that CAP burdens are reduced, a whole host of corollary decisions regarding CAP structure and operation are also presented.

Q. WHAT DO YOU RECOMMEND?

A. Note that in amending its CAP Policy Statement, the PUC explicitly "urged" utilities to incorporate the CAP Policy Statement amendments, including the revised energy burdens, "in their USECPs." The importance of this is that there is a specific process established for revised USECPs. That process does not involve base rate proceedings.

Based on this discussion, I recommend that whether, and to what extent, Columbia Gas reduces its CAP burdens, as well as whether, and to what extent, Columbia Gas adopts other CAP cost control mechanisms at the same time it considers a reduction in CAP burdens, should be deferred to the Commission's consideration of Columbia's revised USECP.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

<u>VERIFICATION</u>

I, Roger D. Colton, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 4-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 14, 2021
*313442

Signature: ______________________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement No. 4-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

	:	
Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania	:	
	:	

Surrebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4-SR

July 27, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT AND REBUTTAL TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of John Zalesky (I&E St. 1R) regarding a COVID-19 emergency relief program. In addition, I respond to the Rebuttal Testimony of Deborah Davis (CPA St. 13-R) regarding low-income issues.

PART 1. Response to I&E Witness John Zalesky.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. Mr. Zalesky testifies that while he is "empathetic to the hardships many ratepayers are experiencing as a result of the pandemic" (I&E St. 1-R, at 3), he does not believe that additional resources are needed to address the needs of those ratepayers experiencing hardship. He asserts, "there has been speculation that workers have not been returning to their previous jobs or accepting available jobs. . ." (Id., at 4). Mr. Zaleksky's concerns are now out-of-date. Beginning with the week of July 11 through July 17, 2021, the Pennsylvania Office of Unemployment Compensation has reinstated its work search requirements. Work search requires all Unemployment Compensation (UC), Pandemic Emergency Unemployment Compensation (PEUC), or Pandemic Unemployment Assistance (PUA) claimants to apply for two jobs and complete one work search activity every week.

Mr. Zalesky further states that while disclaiming to "speak for Columbia," he "believes" that "Columbia's decision to not request a COVID-19 relief plan for its customers in this rate proceeding. . .indicates that what the Company is already doing is sufficient." (Id., at 5). Adopting that reasoning would be a dangerous precedent to set (i.e., that the failure of a utility to address an issue is an indication that what the utility is doing "is sufficient").

Mr. Zalesky asserts that things are getting better, given that "more and more Pennsylvania's are becoming vaccinated and the economy is reopening. . ." (Id., at 3). While he notes that 6.9% of Pennsylvanians are still unemployed, fifty percent higher than the percent unemployed before the pandemic (Id., at 4), at least the unemployment rate is not as high as it was "at the height of the pandemic in April 2020." (Id.).

Q. ARE THINGS GOING AS WELL AS MR. ZALESKY SUGGESTS IN HIS REBUTTAL TESTIMONY?

A. No. Consider the weekly COVID-19 impacts for the Week 28 (April 14 through April 26) (the first week of Phase 3.1 of the Census PULSE Surveys) through Week 33 (June

23 through July 5) (the most recent PULSE Survey available). The updated PULSE Survey data is presented in the Table below. In the Table, the income ranges where the percentage of Pennsylvania residents having no difficulty at all in paying usual household expenses is *lower* in Week 33 than it was in Week 28 is shaded in yellow. In contrast, in the Table, the income ranges where the percentage of Pennsylvania residents having a "somewhat" or "very" difficult time is *higher* in Week 33 than it was in Week 28 is shaded in blue.

Table 1. Difficulty in Paying Usual Household Expenses (by income)
(Week 28 through Week 33 of Census COVI-19 PULSE Survey)

	Not at All Difficult				Somewhat or Very Difficult			
Week	Below $25,000	$25,000 - $34,999	$35,000 - $49,999	$50,000 - $74,999	Below $25,000	$25,000 - $34,999	$35,000 - $49,999	$50,000 - $74,999
28	20.6%	33.6%	51.6%	52.1%	54.8%	45.8%	21.4%	18.6%
29	25.2%	25.5%	45.7%	55.7%	48.6%	54.6%	29.0%	19.0%
30	19.7%	26.5%	45.2%	56.6%	56.5%	47.1%	30.7%	19.7%
31	25.2%	28.7%	44.4%	47.9%	50.2%	53.9%	20.6%	26.3%
32	18.2%	30.6%	44.4%	59.1%	53.0%	45.8%	30.6%	24.9%
33	25.6%	26.2%	48.7%	58.7%	49.3%	57.2%	28.3%	19.5%

The Table demonstrates that in only two of the four income ranges have the lack of payment difficulties decreased. The Table further documents that in three of the four income ranges have the extent of "somewhat" or "very" difficult times in paying usual household expenses increased. The decrease in the number of residents having no payment difficulties, along with the increase in the number of residents having substantial difficulties, has occurred notwithstanding the presence of federal stimulus dollars.

Q. IS THERE ANY OTHER SIGNIFICANT OBSERVATION FLOWING FROM THE TABLE ABOVE?

A. Yes. The Table above shows that only one-of-four instances of persons with income below $35,000 are having no difficulty in paying their usual household expenses. Three-of-four Pennsylvanians at these income ranges are still having difficulties. Indeed, more than half of residents with income as high as $25,000 to $35,000 are having some difficulties in paying their usual household expenses. In fact, despite Mr. Zalesky's testimony about how much better things are today, 50% to 60% of Pennsylvania's residents with income less than $35,000, as of the most recent week for which data is available, are having a "somewhat" or "very" difficult time in paying their usual household expenses. More than one-in-four households with income between $35,000 and $50,000 are having a somewhat or very difficult time, compared to nearly one-in-five residents with incomes of $50,000 to $75,000.

I conclude that Mr. Zalesky provides no basis for disallowing my proposed COVID-19 relief program.

Q. PLEASE RESPOND TO MR. ZALESKY'S PROPOSED MODIFICATIONS TO YOUR RECOMMENDED COVID-19 RELIEF PROGRAM.

A. Mr. Zalesky makes three recommendations regarding a Columbia COVID-19 emergency response program in the event that the PUC approves my proposal. First, he recommends that a dollar ceiling be placed on program expenditures, which ceiling should be set at $400,000. (I&E St. 1-R, at 5). This ceiling is consistent with the ceiling I recommended in my Direct Testimony (OCA St. 4, at 23) and I do not oppose it. Second, Mr. Zalesky recommends that the Commission "express a clear end date or termination date for the ERP such as June 30, 2022." (I&E St. 1-R, at 6). With the caveat that I recommended in my Direct Testimony (that such a date could be extended by motion of a stakeholder or on the Commission's own motion), this is the same date I recommended in my Direct Testimony. (OCA St. 4, at 22 – 23), and I do not oppose it (given my recommended caveat). Finally, Mr. Zalesky recommends that the program be fully funded by CPA shareholders, arguing that "the financial burden of this program should not be placed on ratepayers who have been and intend to continue paying their gas bills in full and on-time." (I&E St. 1-R, at 6). This recommendation should be disapproved.

The issue is not one of the extent to which some ratepayers "intend to continue paying their gas bills in-full and on-time." As my Direct Testimony establishes, and the data I discuss above further confirms, the economic crisis which arose from the COVID-19 health pandemic continues to adversely affect a certain portion of CPA customers. A customer's "intention to pay" is not at issue; the short-term "inability to pay," as created by the COVID-19 economic crisis, is what the emergency relief program is addressing. No-one is "at fault" for having been placed in the economic situation of being unable to pay their CPA bills during the COVID-19 economic crisis. Adopting a continuing emergency relief program, as I proposed in my Direct Testimony, is the most effective, most efficient, way for CPA to respond to that continuing economic crisis. The economic crisis will not continue forever and CPA will not need to provide emergency relief on an ongoing basis. As Mr. Zalesky and I both agree upon, the relief is limited, both in terms of dollars and in terms of time.

Part 2. Response to CPA Witness Deborah Davis.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. I respond to the following basic issues that Columbia Witness Davis addresses in her Rebuttal Testimony: (1) the need for a COVID-19 relief program; (2) the need for improved low-income outreach by Columbia Gas; (3) the need to address the unreasonable number of CAP participants being removed from the CAP for a failure to recertify; and (4) the recovery of CAP administrative costs.

Q. HOW DO YOU RESPOND TO THE REBUTTAL TESTIMONY OF DEBORAH DAVIS REGARDING YOUR PROPOSED COVID-19 RELIEF PROGRAM?

A. Columbia Witness Davis states that "due to the numerous resources currently available to eligible households, the Company does not support an additional COVID relief program at this time." (CPA St. 13-R, at 2). She asserts first that the Company has sufficient funds in its expanded hardship fund such that "based on the current average grant, the Company can assist an additional 2,500 customers with existing funds." (Id., at 2). She does not mention that under normal circumstances, CPA provides between 1,100 and 1,200 hardship grants a year. (OCA-V-21). The incremental assistance that is available through 2022 to provide COVID-19 assistance beyond the hardship grants normally given, particularly given the increased income eligibility, is thus not substantial.

Q. DOES MS. DAVIS REFERENCE FEDERAL "STIMULUS" FUNDING AS A REASON FOR COLUMBIA TO PROVIDE NO FURTHER ASSISTANCE?

A. Yes. Mr. Davis states that "Pennsylvania received $564 million to implement the Emergency Rental Assistance Program (ERAP) to provide rental and utility assistance for households with income at 80% of the Area Median Income (AMI)." (Id., at 2). Her reference is akin to the reference of Mr. Zalesky to "federal government aid including various stimulus payments. . ." (I&E St. 1-R, at 5). While Mr. Zalesky does not reference ERAP in particular, I will assume that his reference is to the same federal program that Ms. Davis mentions.

Ms. Davis does not mention important limitations on the federal ERAP funding she cites. For example, she does not mention that ERAP assistance is available only to renters. According to 2019 Census data (ACS Table B25117), only one-quarter (26.5%) of the housing units in CPA's service territory using natural gas for home heating are renter-occupied. In some of CPA's counties, the percentage falls below 20%. In *<u>none</u>* of CPA's counties does the percentage fall above 40%. Three out of four CPA customers, in other words, do not qualify for ERAP assistance.

Ms. Davis does state that "the Company has heard of the potential of other available resources such as Community Development Block Grants ("CDBG") grants and assistance for home owners that will provide further utility assistance to eligible households." (CPA St. 13-R, at 3). CDBG dollars devoted to utility assistance, however, are a decision of counties, not of the state. Only a limited number of counties are big enough to receive direct federal grants of CDBG dollars. And those counties are not necessarily served by CPA. For example, only the counties of Allegheny, Beaver, Washington, Westmoreland, and York are substantially served by CPA and are entitlement counties. (Chester, while an entitlement county, has only Coatesville which is served by CPA and is thus not further considered here.) None of these counties lists a CDBG-supported COVID-19 utility assistance program on their respective CDBG website.

In addition, due to the nature of CDBG funding, CDBG-funded assistance is not what many people think of when they think of "utility assistance." In order to qualify for such CDBG-funded assistance, for example, an applicant must often demonstrate that they are either homeless or in danger of homelessness.

While Ms. Davis notes that ERAP provides "rental and utility assistance" for income-eligible households, she does not go on to disclose what percentage of the ERAP funding is devoted to "rental assistance" and what proportion is devoted to "utility" assistance. She does not report that, through May 31, 2021, nearly 60% of the households assisted through ERAP received rental assistance, not utility assistance. Even more substantially, households who receive rental assistance receive far more dollars of benefits than households who receive utility assistance. The funding devoted to rental assistance, compared to the funding devoted to utility assistance, is presented in the Table below.

Table 2. Pennsylvania Statewide ERAP Assistance by Type of Assistance by Month (PA DHS ERAP Monthly Report to PA Legislature)				
	A	B	C	D
	Rental Assistance	Utility Assistance	Total Assistance[1]	Percent Devoted to Utilities (B / C)
March/April 2021	$11,924,104.10	$1,829,612.56	$15,488,966.50	11.8%
May 2021	$29,215,994.51	$2,732,285.66	$33,858,028.66	8.1%

One thing that Ms. Davis does not disclose is that, unlike LIHEAP, the "utility assistance" is available not merely for home heating and cooling, but for electricity and water/sewer service as well. Indeed, ERAP "utility assistance" can even be used to pay for trash removal and internet bills. In addition, the term "utility assistance" should not be misconstrued to provide assistance only to regulated utilities. ERAP assistance used to pay for "utility assistance" is divided not only between regulated energy utilities, water/sewer, trash removal, and internet bills, but is further divided due to availability for unregulated bulk fuels such as fuel oil. When this relatively small pie, in other words, is divided into multiple parts, the piece of the pie available to CPA is not necessarily very large.

Q. IS THERE ANY OTHER LIMITATION ON THE ERAP ASSISTANCE THAT MS. DAVIS DID NOT MENTION?

A. Yes. Ms. Davis reports that Pennsylvania received $564 million to implement the ERAP program. She does not report, however, counties have a limited right to access those

[1] A limited amount of the funding is devoted to "other expenses related to housing." Accordingly, the total is greater than the sum of rental and utility assistance.

funds. Each county in Pennsylvania receives a prescribed allocation of funding from the state's ERAP total. Through April, for example, the last month for which data is available, of the 31,470 ERAP applications that had been approved in Pennsylvania, 20,174 (64.1%) had come from Philadelphia County. Overall, of the $564.1million that Pennsylvania will receive in ERAP funds for the entire state, less than 40% of those dollars have been allocated to counties in which Columbia has *any* presence. Even of those funds, the bulk of the funding goes to counties where Columbia has a small presence relative to the competing rental and energy needs (along with water, trash, internet and the like as I explain above) in the counties (e.g., $43.7 million to Allegheny County; $18.l9 million to Chester County; $16.2 million to York County). While Ms. Davis cites the state total of $564 million in her testimony, as a very *big* number, one should take into account also, that the likelihood of any substantial part of that $564 million coming to Columbia Gas customers is quite small.

Q. PLEASE RESPOND TO MS. DAVIS' TESTIMONY REGARDING COLUMBIA'S HARDSHIP FUND RELATIVE TO YOUR EMERGENCY RELIEF PROGRAM.

A. Ms. Davis argues that "the major difference between Mr. Colton's proposal and the Company's Hardship Funds is the benefit level. Hardship Funds currently assist customers with a maximum benefit of $500. Mr. Colton's proposal recommends limiting the benefit to $200 or 25% of the customer's arrears, whichever is greater. This is more often than not much less than a $500 benefit. The existing hardship fund would be more advantageous to customers." (CPA St. 13-R, at 4).

Providing a higher benefit at a single point-in-time, as Ms. Davis notes the Columbia Hardship Fund does, is not synonymous with being "more advantageous to customers." The Hardship Fund will only provide benefits so long as there is money available to distribute. As I note above, however, even at historic participation numbers for Columbia's hardship funds, it will quickly run out of money given the dollars Ms. Davis states are available. One problem, however, is that Columbia is offering more money to a greater number of people than it has historically offered. In 2020, for example, Columbia provided barely $400 in hardship funds per customer, not $500. In 2019, Columbia's hardship grants were less than $400 per recipient. (OCA-V-21). In contrast to these historic numbers, Columbia is now providing hardship grants that are 25% bigger ($500 vs. $400) to customers with maximum incomes that are substantially higher (300% of Poverty Level vs. 200% of Poverty).

The COVID-19 emergency relief program I proposed in my Direct Testimony is designed to help Columbia Gas customers get through more than the next few months as the rate of vaccinations ramps up. As I demonstrate in my Direct Testimony, the economic crisis associated with the COVID-19 pandemic is likely to last far longer than the public health crisis. In this regard, Mr. Zalesky's comments about the rate of vaccinations in Pennsylvania does not address the problem I have identified. Accordingly, my proposal is narrowly targeted to address the payment difficulties that are associated with the COVID-19 economic emergency through at least the middle of 2022.

Q. DOES YOUR PROPOSAL OTHERWISE MIRROR COLUMBIA'S PREVIOUS PROPOSAL?

A. Yes. As I stated in my Direct Testimony (OCA St. 4, at 22), my proposal in this proceeding was intended to build on the Columbia Gas RIGP as originally proposed, but without recommending that it be funded through a reduction in otherwise available hardship funds. In that original proposal, Columbia Gas proposed to offer one-time grants to households that meet the following eligibility requirements: (1) income less than 300% of the FPIG; (2) have experienced a loss of income due to the COVID-19 pandemic; (3) have accrued an overdue account balance between $100 and $600 since the Governor's March 19, 2020 Executive Order; and (4) are not eligible for CAP or Hardship Fund.[2] In this regard, while Ms. Davis asserts that "Mr. Colton's proposal does not explicitly offer an income guideline. The Company's prior proposal also did not include an income guideline, but rather a documented drop in income," the Commission's July 2020 Order (Docket P-2020-3019578, Order, at 16, July 16, 2020) stated that "Columbia Gas proposes to offer one-time RIGP grants to households that meet the following eligibility requirements: Income less than 300% of the FPIG."

Q. PLEASE RESPOND TO MS. DAVIS' TESTIMONY REGARDING THE REMOVAL OF CAP CUSTOMERS DUE TO A FAILURE TO RECERTIFY.

A. The Rebuttal Testimony provided by Ms. Davis regarding the need to reduce the number of customers who are removed from Columbia's CAP due to their failure to recertify

[2] While not duplicated here, CPA also detailed the required documentation of eligibility.

largely fails to respond to the problems identified in my Direct Testimony. For example, Ms. Davis responded by noting that the Commission has previously ordered Columbia to "increase the rate of recertification." (CPA St. 13-R, at 6). Ms. Davis notes, however, that the PUC order was dated August 2019. (Id.). In addition, Ms. Davis does not address the fact that Columbia's own Evaluator stated in CPA's most recent Universal Service Program Evaluation that ""Failed to Recertify was one of the top reasons that customers were removed from CAP in 2016." (USP Evaluation, at Finding CAP-11, OCA-V-22, at 36). Nor did she acknowledge that the Company's own USP Evaluation provided: "*This continues to be an ongoing issue*." (OCA-V-22, at 42) (emphasis added). (OCA St. 4, at 59). She does not acknowledge that five years later, the <u>*same*</u> problem continues to present itself. She also does not respond to my conclusion that "For a company with an average participation of fewer than 23,000 customers since October 2019 (OCA-05-15), however, to lose 10,656 participants due to mobility or a failure to recertify is a major shortcoming in the Columbia Gas CAP. And, it is a shortcoming that was identified by the Company's own program evaluation in September 2017. . ." (OCA St. 4, at 60).

Ms. Davis testifies that CPA has a process in place that addresses the situation of where customers change service addresses but do not leave the CPA service territory. She states that "The Company's current (and long standing) procedure is for its billing system to automatically transfer a customer's CAP plan to the new account without a loss of CAP benefits." (CPA St. 13-R, at 5). To the extent that is accurate, the issue of changed service addresses within the CPA service territory is not a problem. However, the issue of excessive exits extends far beyond the question of changed service addresses within the service territory. As I demonstrate, and as Columbia's own universal service evaluation noted five years ago, Columbia Gas has an ongoing problem with excessive CAP exits which will not be solved exclusively by addressing CAP customers who move within the CPA service territory.

Finally, Ms. Davis asserts that the 2020 experience with exits due to recertifications was atypical due to COVID-19. She argues that "the Company respectfully suggests at this time it is too difficult to measure any one specific catalyst to affect a change (positive or negative) in the number of recertifications. Any metrics should be developed only after the Company has time to balance the current dynamics." (CPA St. 13-R, at 8). In asking for this additional "time to balance the current dynamics," however, what Ms. Davis does *not* explain is why providing *additional* time four years after its Evaluation identified the problem –not only did the Evaluation identify the problem, but the Evaluation found that "this *continues* to be an *ongoing* issue," indicating the issue had been identified *previous* to the 2016 data—would result in greater action or attention without Commission direction than has been directed to the issue in the past five or more years (in 2016, the CPA CAP evaluation found that the failure to recertify was found to "*continue* to be an *ongoing* issue")..

Ms. Davis outlines a limited number of steps that the Company takes to inform CAP participants of their need to recertify. She argues, however, that "the Company has not been able to fully analyze results since it is not removing for failing to recertify income at this time." (CPA St. 13-R, at 7). Ms. Davis goes on to assert, however, that "Any metrics should be developed only after the Company has time to balance the current dynamics." (CPA-13-R, at 8). Ms. Davis, however, has the process backwards. CPA should not assess the actions the Company is taking, and then develop metrics of effectiveness afterwards. The metrics should be developed at the beginning of the process and then applied to determine the effectiveness of the program. If nothing else, the metrics are used to measure the success of the Company's actions, rather than being structured to fit whatever analysis the Company has already performed.

Q. PLEASE RESPOND TO MS DAVIS' REBUTTAL TESTIMONY REGARDING LOW-INCOME OUTREACH AND CUSTOMER INTAKE.

A. Ms. Davis argues that Columbia's performance regarding low-income outreach and customer education should be excused because the Commission's previous critique was "submitted by Commissioners in early 2020, right before a stay at home mandate was issued in Pennsylvania." (CPA St. 13-R, at 8). She argues that "Mr. Colton's apparent expectation that the Company should have addressed and responded to these efforts in a meaningful way with demonstrative results is simply not reasonable." (Id., at 8 – 9).

Ms. Davis' argument does not address some of the fundamental findings that I made. These findings have ***nothing*** to do with a stay-at-home order, or with the COVID-19 pandemic. Consider:

- The Commission said that "besides the community-based organizations Columbia already is working with, there are other local organizations it can partner with, such as food banks. . ." When Columbia Gas listed its community partners, however, no community food banks were listed, even though Pennsylvania has an organization (Feeding Pennsylvania) which has nine member Food Banks serving 2,700 local partners agencies (such as community and church food pantries, soup kitchens, and emergency shelters) serving all 67 Pennsylvania counties. By itself, the Feeding Pennsylvania organization serves two million persons annually throughout Pennsylvania. (OCA St. 4, at 46).

- The Commission said that "besides the community-based organizations Columbia already is working with, there are other local organizations it can partner with, such as. . . schools." Despite this specific direction, when Columbia Gas listed its "community partners," of the 135 school districts in its service territory, Columbia Gas has identified one (1) (Central York School District). (OCA St. 4, at 46).

- The Commission said that "besides the community-based organizations Columbia already is working with, there are other local organizations it can partner with, such as. . .Head Start or other preschool programs." Despite this specific direction, when Columbia Gas listed its "community partners," it identified Head Start programs in only three counties (Beaver, Lawrence, Washington) of the 26 counties in its service territory. (OCA St. 4, at 46).

In addition to not explaining why it did not pursue these specific directions by the Commission –identifying food banks, Head Start programs, and school districts would not have been affected by Pennsylvania's stay-at-home mandate-- Company witness Davis does not explain why Columbia Gas specifically failed to act on the outreach the Commission explicitly directed utilities to pursue. In 2019, the Commission told utilities, including Columbia, that "While utilities have flexibility as to the contents of their plans, the plans should reflect focused consumer education and outreach efforts, tailored to the demographics of their individual service territories, spanning the duration of the universal service plan period. *In particular, these plans should identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG*. (Final Order, at 79, Docket No M-2019-3012599 (emphasis added).

Instead of developing outreach efforts "tailored to the demographics" of its service territory, including "efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG," when Columbia was asked to provide all criteria used to target outreach, Columbia stated that it targeted customers who were past-due, those who "called the Company and identified themselves as low-income," those receiving a LIHEAP grant in the past, those with income between 150% and 250% of Poverty, and seniors and veterans. (OCA-V-30).

Efforts to reach those customers with income below 50% of Poverty were ***not*** identified. In fact, when asked for a "detailed explanation" of how Columbia Gas complied with the Commission directive to "in particular. . .identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG," Columbia responded simply that it "promotes outreach to *all* low income customers using a variety of channels." (OCA-V-35) (emphasis added). (OCA St. 4, at 56 – 57). Ms. Davis did not even attempt to explain why Columbia chose not to engage in the targeted outreach, which the Commission had directed it to pursue six months before anyone had ever heard the phrases "coronavirus" or "COVID-19." Ms. Davis did not explain why, after being directed by the Commission to engage in specific efforts to educate and enroll customers below 50% of Poverty, it chose instead simply to continue to "promote outreach to ***all*** low-income customers. . ."

Q. DO YOU HAVE A RESPONSE TO THE DISCUSSION OF CPA'S PROPOSAL TO DEVELOP A "CONCIERGE" SERVICE FOR OUTREACH?

A. Yes. CPA Witness Davis states that "the Company proposes a new outreach campaign to assist and link customers to available resources and promote all programs. The Campaign will include TV ads, social media and digital ads, written materials, website modifications and a pilot concierge component to assist its lowest income customers to apply for programs." (CPA St. 13-R, at 4). She states that "the Company will contract with a part time consultant to proactively reach out to customers with incomes less than 50% of poverty that are in arrears and have not applied for available resources." (CPA St. 13-R, at 4-5).

I believe that this proposal is a substantive step forward in having CPA meet its obligations to provide targeted outreach to customers with income at or below 50% of Poverty. A dedicated initiative such as that which Ms. Davis calls CPA's "concierge" initiative would allow CPA to seek out expertise that does not currently exist on the in-house CPA staff. It would allow CPA to identify and use grassroots boots-on-the-ground messengers to promote the Company's universal service programs. I recommend its approval.

Q. PLEASE RESPOND TO THE DISCUSSION OF THE USE OF GOVERNMENT PROGRAMS SUCH AS FOOD STAMPS (SNAP), CASH ASSISTANCE AND SSI AS A MEANS OF OUTREACH FOR CAP AND OTHER LOW-INCOME CPA PROGRAMS.

A. Ms. Davis argues that CPA should not be required to identify programs with overlapping eligibility guidelines as a means of identifying particular income groups to whom universal service outreach should be directed. She references to the process of identifying such overlapping programs as “chasing down these outreach avenues individually. . .” (CPA St. 13-R, at 11). She argues that the government agencies administering food assistance benefits (SNAP) and disability benefits (SSI) should instead take on the responsibility of promoting CPA’s bill assistance programs. (Id.) She further argues that these government agencies “could promote these programs statewide more cost effectively, and receive funds for this purpose.” (Id., at 11). Government agencies, however, do not have as one of their purposes the task of promoting programs to help regulated utilities reduce their uncollectibles, improve their collections, or reduce the number of involuntary utility disconnections for nonpayment. Moreover, public agencies such as those providing food assistance operate within statutorily-imposed administrative costs limitations. It is not even clear that promoting a utility bill assistance program would represent an “administrative” cost for an agency such as those who administer food assistance (SNAP) or disability assistance (SSI).

In contrast, the Commission has long recognized the benefits from utilities using public assistance programs to help target bill assistance programs. The federal telephone Lifeline program in Pennsylvania, for example, uses programs such as Medicaid, Supplemental Security Income, Veteran’s Pension, federal Public Housing Assistance, SNAP, and certain Tribal programs as a basis to promote Lifeline enrollment. Ms. Davis’ testimony is at odds with long-standing Commission policy regarding the advantages of using public programs as a means of identifying potentially-eligible assistance recipients.

Q. PLEASE RESPOND TO THE DISCUSSION OF COMPANY WITNESS DAVIS REGARDING REDUCTIONS TO THE CAP BURDENS.

A. CPA witness Davis states that "The Company continues to hold the position that it should not change its CAP payment plan structures without considering the impact of and changes on other control features." (CPA St. 13-R, at 15). She goes on to state that "factors such as usage, maximum CAP credits, minimum payments and other available resources should be reviewed as part of any program design changes." (Id., at 15 – 16). This "position" of CPA is consistent with my Rebuttal Testimony to CAUSE-PA witness Harry Geller. (OCA St. 4R, at 7 – 8). I agree with the Rebuttal Testimony of Ms. Davis in this regard.

Q. PLEASE RESPOND TO MS. DAVIS' REBUTTAL TESTIMONY REGARDING THE ADMINISTRATIVE COSTS WHICH YOU RECOMMENDED DISALLOWING.

A. Ms. Davis offered several internally inconsistent reasons why she believes the CAP administrative costs, which not only remained constant during the COVID-19 pandemic, but actually increased, should not be disallowed as CAP costs. Ms. Davis argued:

- The administrative costs "are largely fixed charges." (CPA St. 13-R, at 14);
- The fixed administrative costs cover services such as "verifying income," which costs "did not change in 2020 even with less activity because these services were still being performed." (CPA St. 13-R, at 14).
- The fixed administrative cost did not decrease because "costs related to the Company call center also did not decrease in 2020." (CPA St. 13-R, at 14).

Ms. Davis testified that "although the Company's call center received fewer inbound calls than in years past, Customer Service Representatives made outbound calls to all customers that were in arrears to explain programs including LIHEAP and CAP." (CPA St. 13-R, at 14 – 15).

Ms. Davis' own testimony provides additional reasons for the Commission to disallow CPA's inclusion of administrative costs in its CAP cost recovery. For example, it is simply not accurate for Ms. Davis to assert that services such as "verifying income" were "still being performed." Ms. Davis, herself, testified that "in response to the pandemic, the Company stopped removing customers for failing to recertify in March 2020 and does not intend to reinstate that provision prior to December 2021." (CPA St. 13-R, at 6).

I should again emphasize that my argument is *not* that CPA stopped doing income verification *entirely*. However, as I documented in my Direct Testimony, as to "outside services," CAP enrollment through "community-based organizations" declined by enarly 40% from 2019 to 2020; CAP enrollment through the "distribution company" declined by nearly 60%; and total CAP intake declined by more than 40%. (OCA St. 4, at 63). These declines occurred at the same time that CAP administrative costs *increased*.

Second, the fact that "costs related to the Company call center did not decrease" because "Customer Service Representatives made outbound calls to *all customers that were in arrears* to explain programs *including* LIHEAP and CAP" (emphasis added) is another indication that those costs should not be recovered as universal service costs. CAP administrative costs are not intended to include calls that are directed to "all customers in arrears." Such outbound phone calling is not part of universal service administration. Nor should CAP be called upon to financially support outbound phone calling by CPA's call center for programs that do *not* involve universal service programs.

Nor is it accurate for Ms. Davis to assert that the CAP administrative costs are "largely fixed monthly fees." (CPA St. 13-R, at 14). As my Direct Testimony demonstrated (OCA St. 4, at Table 18, page 63), more than half of the CAP administrative costs claimed by CPA are for "call center costs," with another one-quarter involving "application fees." Ms. Davis' assertion about what CAP administrative costs "largely" are comprised of is demonstrably in error.

Q. PLEASE RESPOND TO THE REBUTTAL TESTIMONY OF MS. DAVIS REGARDING LOW USE CUSTOMERS.

A. Referring to low-income customers who are low use customers, CPA Witness Davis argues that "There is no value in having customers subsidize bills for other customers who can afford their entire bill or perhaps afford it with the help of a LIHEAP grant.' (CPA St. 13-R, at 13). There is, however, no suggestion in my testimony that "customers [should] subsidize bills for other customers who can afford their entire bill." My testimony explains instead explains how CPA can take greater steps to comply with the CAP outreach that the Commission has previously directed Columbia to pursue, including outreach targeted specifically to the lowest income customers. At no place do I recommend that Columbia should enroll customers in CAP that meet the Commission's affordability guidelines without such CAP participation. Moreover, Ms. Davis errs in arguing that the Commission should consider whether some customers “can afford their entire bill. . .with the help of a LIHEAP grant.” As Ms. Davis, herself, notes elsewhere in her testimony, “LIHEAP cannot be counted towards income or used as resource for other programs. . .” (CPA St. 13-R, at 18).

Q. WHAT DO YOU CONCLUDE?

A. For all of the reasons stated in my Direct Testimony, in addition to the reasons articulated above, Columbia’s claim for CAP administrative costs should be disallowed. Those costs should be excluded from the CAP rider.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 4-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 27, 2021
*314210

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

COMMONWEALTH OF PENNSYLVANIA

June 30, 2021

Deputy Chief Administrative Law Judge Joel H. Cheskis
The Honorable John Coogan
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. Duquesne Light Company 1308(d) Proceeding / Docket No. R-2021-3024750

Dear Judge Cheskis and Judge Coogan:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

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

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

Sincerely,

/s/ Sharon E. Webb

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

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024750**
DUQUESNE LIGHT COMPANY	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design
Small Business Initiatives
EV Charging Programs

Date Served: June 30, 2021

Date Submitted for the Record: ____________________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Witness Identification and Summary of Conclusions

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

A. My name is Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. I specialize in the economic analysis of basic industries. My consulting practice currently consists primarily of the preparation of analysis and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit IEc-1.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review the filing of Duquesne Light Company ("DLC" or "the Company"), to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. My evaluation is generally limited to issues of cost allocation, revenue allocation and rate design. I also address the various initiatives for small businesses, in which the Company proposes that it impose higher rates on some general service customers for the benefit of other general service customers. I also present OSBA's policy positions and my analysis of the variety of programs proposed by DLC for subsidizing the development of charging infrastructure for electric vehicles ("EVs").

Q. Is this testimony complete?

A. No. Due to a communications snafu with OSBA, I was unable to conduct timely discovery. This testimony is therefore based on my review of the Company's filing.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 provides a brief overview of the rate classes under which small and medium businesses take service.
- Section 3 presents my evaluation of the Company's allocated class cost of service study ("ACOSS").
- Section 4 reviews the Company's proposed allocation of the rate increase ("revenue allocation") among the various rate classes.
- Section 5 reviews the Company's proposed rate design for the rate classes under which small and medium businesses take service.
- Section 6 addresses the various initiatives proposed by the Company related to small and medium general service customers.
- Section 7 addresses the various programs put forward by the Company in this proceeding for investing in and subsidizing electric vehicle charging infrastructure.

2. General Service Rate Classes

Q. Please describe the general service tariff categories at DLC.

A. The non-residential tariff classes for small and medium customers in the Company's tariff consist of Rate GS/GM, Rate GMH, Rate GL and Rate GLH.

The GS/GM tariff applies to general service small and medium customers. However, this class has distinct sets of tariff charges for three sub-classes: GS, GM customers below 25 kW in maximum demand ("GM<25"), and GM customers at or above 25 kW in maximum demand ("GM>=25").

The nearly 25,000 GS customers are the smallest customers in the class, consisting of customers with average monthly billing demand below 5 kW and new uncategorized customers. Average annual consumption for this class is only about 4,000 kWh, well below the average residential customer use of over 7,000 kWh. Further detail regarding the makeup of this class is requested in discovery. However, in my experience, many of the customers in this type of class are small businesses, but many are not. These customers are generally not demand-metered, and the tariff charges include only a customer charge and an energy charge.[1]

GM customers are split into the below and at/above 25 kW mark (20,200 and 6,800 customers respectively) based on average historical billing demand. The tariff rates include a customer charge, energy charge and billing demand charge. The average usage for GM<25 is about 30,000 kWh (30 MWh) per year, about six times the size of the typical residential customer. For GM>=25, the average usage is considerably larger, at about 310 MWh per year.

The GMH class comprises customers whose "sole method of space heating" is electricity, except that customers may obtain supplemental heat from renewable sources. The Rate GMH customer count is much smaller than the corresponding Rate GM counts, by a factor of 8 to 10. The tariff appears to be designed to be more attractive to heating loads, since the demand charge applies only in the summer months, with a higher energy charge in the non-summer months. For cost allocation purposes, the Company splits the GMH class into GMH<25 kW and GMH>=25 kW, much like the GM subclasses, although the tariff charges are not differentiated. On a per-customer basis, average usage rates for this class and the two sub-classes are similar to those for Rate GM.

The 736 Rate GL customers are general service customers with minimum demand of 300 kW.[2] Average per-customer use is more than ten times that for GM>=25, at about 3,500 MWh per year. The base rate tariff consists of a hybrid fixed/demand charge based on the 300 kW of minimum demand, and a demand charge for peak demand above 300 kW.

[1] Energy charges are those that vary with the total energy consumed over the billing period, measured in kilowatt-hours ("kWh"), a unit of energy. The Company often refers to these as "volumetric" charges. Energy (or volumetric) charges are distinct from demand charges, which are based on the peak usage in a narrow window of time (typically 15 minutes) within the billing period. Demand charges are based on kilowatts ("kW"), a unit of power, or the rate of energy use. Conceptually, an energy charge is comparable to a charge for a vehicle based on miles driven; the demand charge is based on the maximum speed.

[2] The tariff does not appear to indicate how the 300 kW is determined, but since the minimum tariff charge is based on 300 kW of demand, it does not really matter.

Like Rate GMH, Rate GLH is a class limited to customers using only electricity for heat, with demand charges applying only in the summer. Average customer size is similar to that for Rate GL. There are fewer than 90 customers in this rate class.

The Rate GL and GLH classes apply to customers up to 5,000 kW in contract demand, at which point Rate L applies.

Q. Why does the Company have a separate "heating" class for GM and GL customers?

A. I do not know. It may be simply inertia, in which the current tariff reflects a tariff design for integrated utilities, and thus may simply be resistance to change.

The primary reason for establishing a separate rate class is that the customers have distinct cost-to-serve differences. Thus, for example, it could potentially be argued that heating customers are less costly to serve per unit of annual peak billing demand, because winter peaks impose less stress on parts of the distribution system because the system is sized to meet summer peak loads. However, the Company's cost allocation methodology appears to assign demand-related costs to the GMH and GLH classes based on their winter "non-coincident" peaks, thereby implying that there is no cost advantage to heating peak loads. In fact, the average class load factors for the GMH and GLH classes based on the non-coincident peak allocators used in the Company's ACOSS are lower than those for the regular GM and GL classes. Thus, there appears to be an inconsistency between the Company's proposal to retain its special heating classes and the cost of service methodology that determines the cost basis for service.

For the purposes of this proceeding, I recommend that the Company explain why retaining the GMH and GLH classes is appropriate. In particular, the Company should explain why the cost basis for these classes relies on the customers' winter-peak demands, while the tariff charges exclude a winter demand charge.

3. Cost Allocation

Q. What is the purpose of a utility's allocated cost of service study ("ACOSS")?

A. The most important criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[3] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

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

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

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

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

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

whether he should purchase more or less of the utility service. In effect, the consumer balances the value that he receives from the purchase of that service against the utility's cost of providing the service.

Q. What issue is most debated with respect to electric utility distribution company ("EDC") cost allocation?

A. The most contentious issue regarding EDC cost allocation usually revolves around the "classification" and "allocation" of joint use distribution plant costs, including substations, poles, overhead and underground lines, and transformers. This debate arises for several reasons.

- First, this plant represents a substantial portion of the overall distribution plant, making the issue of critical importance to the overall allocation of rate base. Moreover, because O&M costs are substantially allocated in proportion to the allocation of plant, the allocation of plant has a large impact on the allocation of O&M costs.

- Second, unlike meters and service line plant, this plant represents "joint use" costs, meaning that multiple rate classes rely on the same plant. These costs therefore generally cannot be directly assigned to the specific rate class which uses the plant. Rather, the costs must be allocated using some reasonable factors based on cost causation.

- Third, the economics literature provides little theoretical support for the allocation of such costs, other than to state that the allocated costs should lie somewhere between the short-run marginal cost of providing service and the standalone cost of serving a particular class. These guidelines leave considerable leeway for allocating electric distribution plant costs.

- Fourth, the various methodologies offered by cost allocation analysts produce a wide range of cost allocation outcomes.

The debate for allocating joint use distribution plant costs generally revolves around which factors best reflect "cost causation." These factors typically fall into three categories: peak demand, annual energy usage (or its arithmetic equivalent, average demand), and number of customers. These three "classification" factors are generally abbreviated as "demand," "energy" and "customer."

Q. Please describe the issues involved in the classification and allocation of joint-use electric distribution plant costs.

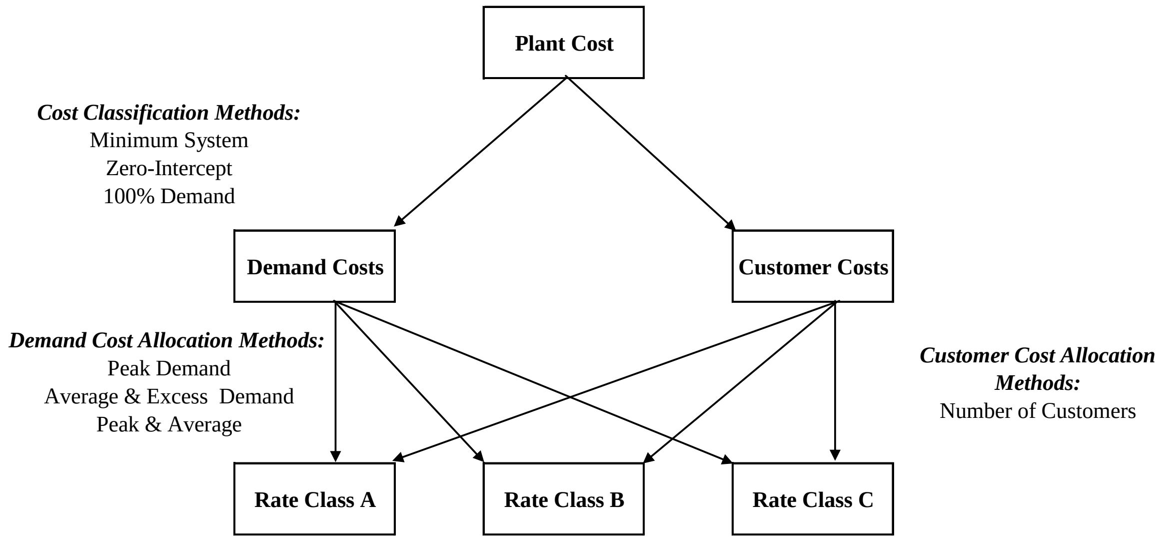
A. An electric distribution system must be designed to meet two objectives. First, the poles, wires and transformers must be large enough to be able to deliver power from the transmission grid to customer premises at the time when the load on each component of the system is the highest. Second, the system must be designed to interconnect all the EDC's customers.

A two-step process is generally used to recognize how these system design considerations cause costs to be incurred and to assign costs to rate classes. First, distribution plant costs are *classified* into "demand-related" and "customer-related" components, to reflect both the peak demand and size of system design considerations. Second, each component of the classified costs is *allocated* among the various rate classes. Customer-related costs are generally allocated on the basis of the number of customers, or the number of customers weighted by relative cost (e.g., for meters and service drops). Demand-related costs are allocated on the basis of some measure of customer peak demand.

Figure IEc-1 below depicts this two-step process schematically, and identifies the primary methodologies used by cost allocation analysts for each step. In my experience, all of these methods are in general use, although experts disagree about which method best reflects cost causation.

Figure IEc-1

Classification and Allocation of Electric Distribution Plant Costs: Summary of Methodologies



Q. Please briefly discuss the electric distribution plant cost *classification* methods shown in Figure IEc-1.

A. The "minimum system" approach is based on the idea that the customer-related component of costs should represent those costs that would be incurred to meet minimal demand levels. It is calculated by determining what the cost of the electric distribution system would be if only minimum-sized poles, wires and transformers were installed. The ratio of the cost of this minimum system to the cost of the actual system is deemed to be the percentage of the cost of the actual system that is customer-related. All costs incurred in excess of the minimum system are considered demand-related.

The minimum system approach is often criticized for failing to recognize that a minimum system has some load carrying capability, and therefore overstates the customer-related component of costs. This critique is addressed by some analysts using a "zero-intercept" methodology. In a zero-intercept approach, the minimum system is based not on the cost of the actual minimum-sized plant, but on the implicit cost of plant with zero load carrying capability. The cost of a zero-capacity transformer, for example, is determined using statistical methods, which show a mathematical relationship between the cost of a transformer and its capacity.

A second criticism of both the minimum system and zero-intercept methods is that it is not clear that the customer portion of costs, as measured in this method, does in fact vary over the longer term with number of customers. There is conceptual appeal in the argument that it costs less per unit of demand to attach one customer with a 100 kW load than to attach 20 customers with 5 kW loads, since serving the smaller customers will generally require more poles, more conductor feet, and more (smaller) transformers. However, neither the minimum system nor the zero-intercept method attempts to measure these scale economies that are related to system topology.

Finally, the "100% demand" approach assumes that all distribution costs are demand-related, and that there is no customer component at all. This method simply assumes that there are no economies of scale related to serving larger customers on the distribution system, and that all customers have the same cost per unit of peak demand.

Q. What is Commission precedent in Pennsylvania for classification of joint-use distribution plant?

A. To my knowledge, Commission precedent was established in a 2012 PPL Electric base rates case, in which the Commission approved the use of a "minimum system" classification approach for both primary and secondary voltage distribution plant.[4] This method included an adjustment for line transformers, to reflect the load carrying capability of the minimum system. This decision was based, in part, on the methodologies put forward in NARUC's 1972 Electric Utility Cost Allocation Manual ("NARUC Manual").

This methodology was confirmed in the fully litigated 2018 UGI Electric base rates proceeding, in which the Commission cited to its decision in PPL Electric and to the NARUC Manual.[5]

Q. Please address the issues relating to the *allocation* of distribution plant costs.

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[4] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2012-2290597, Order Entered December 28, 2012, pages 105- 113.

[5] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2017-2640058, Order Entered October 25, 2018, 159-160.

A. The most common methods for allocating the demand component of electric distribution plant costs are either a peak demand method or the average-and-excess ("A&E") demand method. Under the peak demand method, costs are allocated based on each class's contribution to peak demand. Peak demand methods include coincident peak ("CP"), non-coincident peak ("NCP") and individual customer maximum demand ("ICMD") methods. Under the CP method, costs are allocated based on each class's contribution to a measure of the diversified system peak. That is, the peak demand for each class represents that class' share of demand at the system peak. For NCP, costs are generally allocated based on the diversified sum of peak demands within each class. That is, the NCP allocator reflects maximum demand for the class. Some classes may peak in the winter and some in the summer, and the NCP will reflect the respective peaks, regardless of when the system peak occurs. For ICMD, costs are allocated based on the undiversified sum of each individual customer's peak demand within each class.[6] For electric utilities, generation and transmission demand-related costs are more commonly allocated using a diversified CP method, whereas distribution costs are more commonly allocated using NCP and ICMD methods.[7]

The A&E method allocates demand costs based on a weighted average of "average demand," which is proportional to annual energy consumption, and "excess demand," which is the difference between peak demand and average demand. Depending on the weighting method used, the A&E allocator is often similar to a peak demand allocator, because it is based on an "average demand" measure and a "peak minus average demand" measure.

[6] Load diversity refers to the fact that not all customers experience their peak demand at the same time. Thus, for example, it is not necessary to build electric generation capacity sufficient to meet the sum of the individual peak demands of every single customer on the grid. These "benefits of diversity" necessarily decrease as the electric plant in service gets closer to the individual customers. While generation capacity can reflect the benefits of diversity from all customers and rate classes, local transformers and service drops must generally be sized to meet individual customer peaks.

[7] For distribution system costs, some analysts argue that distribution costs related to peak periods should be allocated using multiple on-peak hours, and that there should be geographic differences in when these high usage hours occur. As smart meters become more prevalent, this approach becomes more technically feasible. However, because PCL&P does not have smart meters, this approach is moot for this proceeding.

In addition, in Pennsylvania and elsewhere, some experts advocate the use of a peak-and-average ("P&A") allocation method for demand costs. In this method, costs are allocated based on a weighted average of average demands and peak demands.

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

A. The Company's cost allocation methodology and the associated ACOSS are presented by Mr. Howard S. Gorman at DLC Statement No. 15. The Company's ACOSS was provided in working electronic format in response to I&E-RS-2-D.

For cost classification, the Company applies a minimum system analysis to its secondary voltage plant, and it adjusts the demand allocator for line transformers to reflect the peak load carrying capability of the minimum system. For the primary voltage system, which represents the vast majority of distribution plant costs, the Company uses a 100 percent demand classification approach.

For cost allocation purposes, the Company generally relies on NCP demand allocators. In so doing, however, the Company segregates its system not only into primary and secondary voltage categories (which is standard practice), but also into network and non-network categories. It also segregates its underground systems into non-network, radial, and underground residential development ("URD") systems. The Company develops separate NCP allocators, generally at both primary and secondary voltage, for each of these asset groupings.

Q. Do you agree with the Company's methods for joint-use distribution plant allocation?

A. I agree that distribution plant costs, particularly secondary voltage distribution plant, should have both a customer and a demand component, for the cost causation reasons discussed earlier, and based on Commission precedent. However, both traditional industry practice and relatively recent Commission decisions imply that primary system costs should also include both a customer component and a demand component.[8] The Company, however, classifies all primary system costs as 100 percent demand-related, and thus is inconsistent with Commission precedent.

[8] Regarding Commission precedent, the example of PPL Electric is discussed in detail below.

As a conceptual matter, I prefer the use of a zero-intercept approach to the minimum system approach for distribution plant cost classification, because the zero-intercept approach addresses the problem of the load-carrying capability of the minimum system. However, because the zero-intercept approach for an EDC is more complicated, more data intensive and sometimes more subjective than a minimum system analysis, the minimum system approach is often preferred. Moreover, Commission precedent supports use of the minimum system method. Thus, I do not object to the use of a minimum system method in this proceeding.

I also agree that a peak demand method is appropriate for allocating the demand-related portion of distribution plant costs. An electric distribution system must be sized to meet peak demands, or customers will see their electric use constrained during peak periods. I also agree that DLC's use of the class NCP allocator for primary system distribution costs is consistent with industry practice, and it reflects a measure of the load diversity that the electric distribution system experiences at primary voltage.[9]

However, at the secondary voltage level, there are few benefits of load diversity for poles, conductors and transformers. These assets must generally be sized to meet the peak demands of a very few customers within a narrow geographic area. Thus, a better allocator would be a sum of individual customer peaks allocator.

Q. Are DLC's cost classification methods consistent with the practices of other Pennsylvania EDCs and industry practice?

A. While I do not believe that the Company's methods are outside the range of industry practice, a reasonable case can be made that some component of primary system plant should be classified as customer-related, rather than classifying all primary system plant as

[9] As a theoretical matter, the NCP is not well justified. Plant assets that are located near customers must be sized to meet the individual customer peaks for customers in that geographic area, not the diversified sum of class peaks. Plant assets that are "deeper" in the system, notably substations, must be sized to meet the diversified demand of all customers "downstream" from those assets, from all classes, not from a single class. Thus, a cost-based allocation approach should be more reflective of coincident peak ("CP") demands for deep system assets, and sum of individual customer demands ("ICMD") for local assets. Nevertheless, using the NCP allocator is traditional and widespread, perhaps because it is something of a compromise between the two alternatives.

demand-related. In that respect, my experience in Pennsylvania EDC cost allocation is as follows:

For many years, PPL Electric used an approach that is conceptually similar to that offered by the Company in this proceeding, in that it used 100 percent demand classification for its primary system and a minimum system approach for secondary distribution plant. However, PPL Electric modified its method to include a customer component for its primary distribution system (excluding substations). The Commission explicitly approved the revised method in December 2012.[10]

In addition, the FirstEnergy EDCs use a minimum system methodology for distribution plant cost classification (excluding substations), applying the analysis to both primary and secondary systems.[11]

Finally, the Commission has recently approved the classification approach used at UGI Electric, which incorporates a customer classification for both primary and secondary voltage systems.[12]

A comparison of classification parameters for the various Pennsylvania EDCs in which I have submitted testimony is shown in RDK WP1, "Classification" worksheet.

Moreover, the NARUC manual for electric cost allocation specifies that distribution plant costs have both a demand and a customer component, and it identifies the minimum system approach as one of the standard methods. It indicates that the minimum system should be applied to both primary and secondary distribution plant (excluding substations). The manual further supports the use of NCP and individual customer demands as allocation

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[10] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2012-2290597, Order Entered December 28, 2012, pages 105-113.

[11] OSBA Statement No. 1, Docket No. R-2016-2537349 et al., pages 9-15.

[12] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2017-2640058, Order Entered October 25, 2018, 159-160.

factors for distribution demand-related costs.[13] The Commission has cited to the NARUC Manual in support of its decisions in PPL Electric and UGI Electric.

Q. Have you developed your own version of an ACOSS?

A. The Company's ACOSS model in this proceeding is unusually complex, and it cannot easily be modified to reflect alternative classification of primary system assets. I have therefore developed a simpler working spreadsheet model that approximates the results of the Company's model, which I have simulated to reflect the changes I propose. Due to the complexity of the Company's model, my version is a reasonable approximation to the Company's model, rather than an exact replication.

Q. Do you have any significant methodological or numerical concerns with the Company's ACOSS?

A. As detailed further below, I recommend that the following modifications be made to the Company's ACOSS methodology:

1. First, the Company's methodology is not consistent with both Commission precedent and the NARUC Manual regarding the classification of primary voltage system joint-use plant.

2. Second, the Company appears to inequitably double-count non-residential loads in allocating overhead conductors and underground conductors/conduit. Non-residential loads are assigned a full share of all overhead and underground plant, while residential customers are assigned a disproportionately small share of underground plant.

Q. How have you addressed the classification of primary voltage system plant?

A. At this writing, I do not have sufficient information to derive the minimum system classification parameters for distribution plant. Based on my review of primary distribution plant classification at other Pennsylvania EDCs, I conclude that the customer portion of primary system costs is generally modestly lower than for secondary system plant. As a reasonable but conservative adjustment, I have therefore classified DLC's

[13] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992, pages 86-92, and 96-97.

primary distribution plant with one-half the customer component of the secondary distribution plant. Thus, for example, where DLC classifies secondary underground conductors/conduit as 44 percent customer-related, I classify the primary underground system as 22 percent customer-related. I expect that a detailed minimum system evaluation of the primary voltage system would produce higher "customer components" for plant costs, based on the results of other Pennsylvania EDCs.

Q. Please address the issue of double-counting non-residential customer demands for allocating overhead and underground assets.

A. As I indicated earlier, the Company takes the approach of developing separate allocators for its underground conductors and conduit, ostensibly to reflect the specific usage for those assets. While this effort to more precisely allocate these specific costs is commendable, it must be undertaken in a careful and consistent manner. In particular, it must be recognized that the underground assets serve to reduce the need for poles and overhead conductors. Thus, the allocation factors for the poles and overhead conductors should be adjusted to reflect the fact that some load is served through the underground assets. Because DLC does not make such an adjustment, non-residential customers are effectively charged a full share of the costs for both underground and overhead assets, while residential customers are not.[14]

As an illustration, Table IEc-1 below compares the peak demands used to allocate primary voltage overhead and underground assets for the RS class and the GM< 25 class. As shown, the Company's allocation method implicitly assumes that the entire GM<25 load is served by underground facilities, while only about 14 percent of the RS load is so served. However, the Company also assumes that the entire load for both RS and GM<25 load is served from the overhead facilities. While DLC implicitly double-counts the loads for both classes, the double-counting is far greater for the non-residential classes than for the residential classes. This unusual approach to cost allocation produces the unusual result

[14] This problem does not appear to apply to the Company's split of costs between "network" and "non-network" cost categories, where both the costs and the allocators are demarcated between the two systems. In addition, this problem does not appear to customer counts for underground assets, where the Company appears to apply a full share to the residential class. However, the Company appears to double-count demands when allocating overhead and underground demand-related costs.

that while Rate RS represents over 41 percent of class primary voltage non-coincident peak demand, it is allocated only 31 percent of primary voltage system costs. Similarly, the primary system costs allocated to non-residential classes tend to be 15 to 40 percent higher than those classes' respective share of NCP demand.

Table IEc-1 DLC Distribution Allocation Factors		
	RS	**GM<25**
Total Primary NCP (kW)	1,153	153
DLC Allocator for Poles and OH (kW)	1,153	153
Percent OH Allocated	100%	100%
Sum of DLC Allocators for UG (kW)	159	153
Percent UG Allocated	14%	100%
Source: RDK WP1 "Allocators" tab.		

Q. How did you adjust for this double-counting?

A. At this writing, I do not have sufficient information to correct DLC's allocation factors for both overhead and underground assets to eliminate inappropriate double-counting. I therefore employed a simple and consistent approach, in which both overhead and underground assets are allocated using the same NCP demand allocators. My approach is consistent with the practice of other Pennsylvania EDCs, which has generally been approved by the Commission.

Q. Did you make any other modifications to the Company's ACOSS methodology?

A. The Company's ACOSS classifies certain costs as customer-related that are more reasonably reflected as demand-related or energy-related. First, the Company incurs uncollectibles costs associated with non-payment of customer bills, which it classifies as 100 percent customer-related. Second, the Company classifies costs for its various social benefits programs as entirely customer-related, such as the various EV program costs.

In general, the Commission's policy in Pennsylvania for costs that are not directly related to the specific ratepayers who must pay for those costs is to recover those costs through energy (or volumetric) charges. In particular, costs for universal service programs are generally recovered in energy charges. Similarly, the subsidy costs for energy efficiency and conservation ("EE&C") programs are similarly recovered in energy charges.

Therefore, to avoid distorting the cost basis for customer charges, I have modified the Company's classification method to treat these costs (where I can identify them) as energy related in my ACOSS. Note that I have not changed the allocation methodology – I have simply reclassified the costs for rate design purposes.

Q. What are the results of your alternative ACOSS simulation?

A. Table IEc-2 below shows class rates of return at present rates for both my near-replication of the Company's ACOSS and my alternative simulation. As shown, the changes that I incorporated into my analysis serve to increase costs to the classes with smaller customers (residential and GS), while reducing allocated costs for larger customers.

Table IEc-2
Comparative Cost Allocation Results
Class Rates of Return at Present Rates

Class	DLC	RDK
RS	5.4%	2.6%
RH	2.6%	1.2%
RA	3.4%	1.5%
GS	5.7%	2.1%
GM<25	6.9%	9.2%
GM>25	4.7%	10.2%
GMH<25	5.5%	6.5%
GMH>25	3.2%	7.6%
GL	6.1%	12.6%
GLH	2.7%	6.2%
L	5.2%	12.7%
HVPS	782.7%	671.6%
SE	11.5%	22.7%
SL	15.1%	16.4%
UMS	2.4%	-1.8%
System	**5.4%**	**5.4%**

Source: RDK WP1, RDK WP2

4. Revenue Allocation

Q. What is revenue allocation?

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

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

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

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

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively price-elastic demand. [15]

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

Q. What is the Commission's standard for measuring progress toward cost-based rates?

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

A. For many years, participants in Pennsylvania utility regulatory proceedings have relied on a metric known as the "indexed rate of return," or "relative rate of return." DLC Witness Ogden confirms that the Company relies on this flawed metric.

The indexed rate of return metric is derived as the ratio of the class rate of return on rate base to the systemwide average return on rate base. Thus, for example, if a rate class is earning 2 percent on rate base at current rates and the system average is 5 percent, the indexed rate of return metric is 2.0/5.0 = 0.4. The metric correctly indicates that this class is under-recovering costs. As a measure of progress, however, the indexed rate of return metric overstates progress toward cost-based rates, and it can falsely show progress when none exists. For example, the indexed rate of return metric will show that an across-the-board rate increase results in progress toward cost-based rates, when in fact such an increase necessarily produces zero progress toward cost-based rates.[16] Unless there is some radical shift in utility cost structure, assigning the same percentage increase to each class in each base rate proceeding simply cannot move rates more into line with allocated cost, as a matter of simple arithmetic. As such, the indexed rate of return metric should not be used to indicate whether a proposed revenue allocation scheme results in any progress toward cost-based rates.

The Commission has recently addressed this concern. In an order involving the City of Bethlehem – Water Department, the Commission concluded:

> "As noted by the OSBA, the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates."[17]

I have therefore relied on the dollar value of subsidies at present and proposed rates in evaluating the progress toward cost-based rates for revenue allocation in this proceeding. In so doing, however, I note that this metric can also be misleading.

[16] See RDK WP1 "Indexed RoR" worksheet for a numerical example demonstrating this result.

[17] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

As a general rule, if a rate class that is under-recovering costs at present rates is assigned an above-average system increase, the revenues for that class are moving more into line with allocated cost. However, the subsidy metric used by the Commission may indicate that the class subsidy in dollar terms is increasing, even if a class that is currently receiving a subsidy is assigned an above-average increase.[18] That is, the subsidy to the class in question may increase in dollar terms, even if it is decreasing as a percentage of base rates.

Thus, for this proceeding, I considered both dollar value of cross subsidies and the revenue-cost ("R-C") ratio metric. The "R-C" metric represents (unsurprisingly) the ratio of class revenues to class allocated costs, and thus implicitly recognizes the subsidy as a percentage of the class revenue requirement.

Q. Is the Company's proposed revenue allocation consistent with its own ACOSS?

A. The Company's revenue allocation proposal is reasonably consistent with its ACOSS results, although it fails to make progress toward cost-based rates for a number of non-residential rate classes. In particular, the GM<25, GMH<25 and GL classes all exhibit class rates of return at present rates that are a little above system-average, but the Company assigns rate increases to those classes that are also moderately above system average. This results in increasing subsidies and R-C ratios moving a little further away from unity for those classes. On a quantitative basis, however, the changes needed to address these inequities are relatively modest, involving a reduction in the proposed increases for these classes of less than 2 percent.

Q. Does your alternative cost allocation analysis imply an alternative revenue allocation?

A. Yes. To develop my alternative revenue allocation proposal, I began by calculating the rate change needed to bring proposed revenues into line with allocated cost using my alternative ACOSS. I then made two adjustments to those values. First, to reflect concerns regarding rate gradualism, I limited the maximum increase to 1.5 times system average. DLC's proposed system average is 15.6 percent, and thus the maximum increase is set at 23.4 percent. Second, I set the minimum rate change at zero, to avoid rate reductions.

[18] See RDK WP1, "Indexed RoR" worksheet.

The net effect of these adjustments is a revenue shortfall of $5.5 million. I then reallocated that shortfall to those classes that are not capped by the 1.5X rule. In this way, all other classes contribute to the subsidy needed for the constrained classes. The details for these calculations are provided in RDK WP2 “Summary” worksheet. My alternative revenue allocation is shown in Table IEc-3 below, compared to the Company’s filed proposal.

Table IEc-3
Comparative Revenue Allocation Proposals

Class	**DLC**		**RDK**	
	$000	%	$000	%
RS	$41,913	14.3%	$68,297	23.4%
RH	$6,316	22.5%	$6,554	23.4%
RA	$728	22.5%	$755	23.4%
GS	$1,658	14.2%	$2,729	23.4%
GM<25	$5,222	15.7%	$861	2.6%
GM>25	$12,011	17.3%	$1,804	2.6%
GMH<25	$583	16.2%	$427	12.1%
GMH>25	$1,311	22.3%	$365	6.6%
GL	$10,152	15.8%	$1,673	2.6%
GLH	$1,620	22.5%	$1,256	17.8%
L	$3,408	18.3%	$485	2.6%
HVPS	$0	0.0%	$8	2.6%
SE	$80	5.4%	$39	2.6%
SL	$521	5.2%	$259	2.6%
UMS	$251	22.5%	$261	23.4%
System	**$85,773**	**15.6%**	**$85,773**	**15.6%**

Source: RDK WP1, RDK WP2

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

Q. What is the Company's general approach to rate design for the non-residential rate classes in this proceeding?

A. For the smallest customers in the Rate GS class, the Company proposes a relatively large increase in the customer charge (30.0 percent), and a more modest increase to the energy charge (14.9 percent).

For the GM, GMH, GL and GLH classes, the Company generally proposes a lower-than-average increase to the customer charge, moderate increases to demand charges and the highest increases to the energy charges. The higher increase for the energy charge is primarily related to "rolling in" the current DSIC charges. As such, the Company is not proposing any major differences compared to the rates that are currently in place. The Company's rate design for all classes is presented in RDK WP1 "RevPrf DLC" worksheet.

Q. Please describe your assessment of the GS tariff.

A. Like most other Pennsylvania EDCs, DLC's tariff charges for the smallest general service customers consist of a flat monthly customer charge and a per-kWh energy charge. A comparison of the Company's proposal with other Pennsylvania EDCs is shown in Table IEc-4 below.

Table IEc-4 Pennsylvania EDC Tariff Rates for Small General Service Customers			
	Rate	**Customer Charge ($/month)**	**Energy Charge (cents/kWh)**
DLC Current	GS	$12.50	7.331
DLC Proposed	GS	$16.25	8.424
UGI Electric*	GS-1	$9.83	4.311
PPL Electric	GS-1	$22.00	**
Metropolitan Edison	GS-Small	$21.88	4.069
Pennsylvania Electric	GS-Small	$18.33	3.624
Penn Power	GS-Small	$24.89	3.623
West Penn Power	Rate 20 GS	$9.52	3.529
PECO	GS***	$14.49	4.78

* Does not reflect current base rate case.
** PPL Electric applies a $4.361 per kW demand charge, as all customers have smart meters.
*** Single-phase service without demand measurement; most PECO GS customers have demand meters, with demand charge of $8.36/kW.
Source: Utility tariffs posted on websites

As shown, the major Pennsylvania EDCs have monthly customer charges in excess of the DLC proposal, and most have materially lower energy charges.

In terms of allocated cost, I rely on a cost metric including all customer-related costs in the Company's ACOSS and my alternative ACOSS (which excludes uncollectibles and social program costs). The Company's ACOSS shows a cost basis of about $29 per customer per month, while my alternative ACOSS implies costs of $39 per customer per month, reflecting the alternative classification of primary voltage system costs. Regardless of the ACOSS used, the Company's proposed customer charge is well below allocated cost.

Finally, it is likely that there are a significant number of GS customers that are not, in fact, small businesses. Each of these customers is attracting customer costs to the class of some $30 to $40 per month in the ACOSS, but providing only a small fraction of that amount in the monthly customer charge.

Q. What, then, do you recommend with respect to Rate GS tariff design?

A. I agree with the Company's proposal to apply a substantial increase to the GS-1 customer charge, and I conclude that the Company has reasonably reflected rate gradualism considerations in doing so. If the Company's overall increase is scaled back, I believe that the scaleback should be applied primarily to the energy charge, thereby retaining the Company's customer charge proposal.

Q. Please provide any specific comments that you have regarding rate design for the two Rate GM sub-classes.

A. The Company's rate design for GM customers consists of a customer charge, an energy charge, and a demand charge for demand above 5 kW. In evaluating the magnitude of the customer charge, it therefore must be recognized that it is implicitly recovering not only customer costs, but demand costs for the first 5 kW.

Regarding the customer charge, the Company proposes to set the customer charge for GM<25 at $63 per month, and for GM>=25 at $76 per month. However, because the proposed demand charge is $7.89 per kW, and most bills presumably have billing demand above 5 kW, the implied customer-related costs being recovered in the customer charge are $23.55 and $35.55 per month for GM<25 and GM>=25 respectively. These values are well below the customer cost values in both the Company's ACOSS and my own, which are $55 and $193 for the Company's ACOSS, and $66 and $200 for my ACOSS.[19]

Thus, the Company's rate design for the GM class does not set the customer charge unduly high. The customer charge for GM>=25 is surprisingly low when compared to allocated cost.

Regarding the energy and demand charges, it is unclear how the Company derived the proposed values, other than through inertia. In the ACOSS, costs not classified as customer-related are almost entirely demand-related, which suggests that the demand charge should dominate cost recovery. At present rates, the demand charges do generate

[19] For heterogeneous classes like GM and even GM<25, the customer charge should reflect the customer-related costs for the smallest customers within the class. While the customer cost for small customers is not easily derived from my ACOSS, that cost should lie between $39 and $66 for GM<25, and between $66 and $200 for GM>=25. These values still lie well below the Company's implied customer charge for these classes.

more revenue than the energy charges, but by only a relatively small amount for the GM<25 class. The higher proposed percentage increases for the energy charge have the effect of increasing the importance of energy charges on bills compared to the result of the last base rate case, which does not appear to be consistent with the Company's ACOSS philosophy.

Including an energy charge in the tariff design may be an effort to protect very low load factor customers, particularly those with peak demands that do not coincide with system or class peaks, from the high bills that would result from shifting cost recovery from energy charges to demand charges.

Thus, at this time, I recommend that the Company explain its rate design philosophy for the GM classes, and explain whether it would be more appropriate to increase the relative importance of customer and demand charges.

Q. Please address the Company's rate design proposal for Rate GL.

A. Rate GL base rates are essentially recovered through a two-block declining block demand charge. The first block is technically a minimum charge for all load up to 300 kW of billing demand. Because the minimum customer size for Rate GL is 300 kW, it is likely that most monthly billing demands exceed 300 kW (although actual billed demand is not currently available to me). The current rates are $10.60 per kW for that first 300 kW block, and $8.41 for all kW in excess of 300. The Company proposes to increase those to $12.25 and $10.66, increases of 15.6 percent and 26.8 percent respectively. In effect, larger customers in the class will experience higher rate increases.

The premium for the first block demand charge is presumably designed to recover customer-related costs, because the tariff has no customer charge. The current differential is $2.19 per kW, thereby implying a customer charge of about $657 for the first 300 kw. With the proposed increase, the premium shrinks to $1.59 per kW, or $477 per month. Both the Company's ACOSS and my ACOSS show customer-related costs for Rate GL of about $390 per month. I therefore conclude that the Company's proposal to shrink the implicit demand charge differential is directionally consistent with costs and reasonable.

Q. Do you have any further comments on tariff design for Rates GMH and GLH?

A. The Company's rate design for these classes is essentially to set the summer rates equal to those for the corresponding regular rate class (GM and GL), and to set the winter energy charge at the level needed to meet the revenue target for the class. As I indicated earlier, the Company appears to have an inconsistency between its costing philosophy and its rate design philosophy for these classes, that should be explained. If, in fact, the Company believes that distribution costs to serve these classes are determined by winter peaks, the Company should consider adopting a winter demand charge for these classes, or simply phasing them out.

As I indicated earlier, the Company should explain its thinking in this respect.

6. <u>General Service Initiatives</u>

Q. Please describe the initiatives proposed by the Company for general service customers in this proceeding.

A. The Company has proposed three initiatives to address perceived problems faced by certain general service customers in its service territory. To the best of my knowledge, the Company proposes that the shareholder contribution for these efforts be zero, and the ratepayer contribution (if any) is 100 percent. In effect, the Company has proposed that its general service customers subsidize efforts to assist some general service customers who were negatively impacted by the pandemic and other economic events.

The proposals include:

1. Rider 19: Community Development for New Load/New Community Development Rider

2. Rider 25: New Business Stimulus

3. Rider 26: Crisis Recovery Program

Q. In general, do you recommend that the Commission adopt these proposals?

A. I do not. Electric distribution utilities should focus on providing safe and reliable service at reasonable and non-discriminatory rates. The Company's proposals, while presumably well-intentioned, represent an attempted expansion of the utility's role in taxing some customers for the benefit of other customers, in an effort to achieve economic and social policy goals. In effect, the utility is usurping the proper role of government, presumably because the utility has determined that the government's efforts are ineffective or insufficient. Moreover, because the utility is not offering any of its own funds in support of these initiatives, it is assuming both taxing and spending authority to achieve these ends.

While utilities sometimes have such a role, it is typically mandated by legislation, such as for residential universal service programs and energy efficiency/conservation programs in Pennsylvania. In both cases, the legislature explicitly assigned the task for those redistributive efforts to the utility. For the general service programs proposed by DLC in this proceeding, I do not believe that such mandates exist.

I acknowledge that, in making these proposals, the Company has put strict time limits on all of the programs, so there is some hope that this is not the start of a large cross-subsidy program for non-residential customers. However, approval of these programs may simply mean that new and more expensive programs will eventually be offered, which will evolve and grow, to the point where the tariff impact on those customers who do not benefit from the programs becomes material. Doubtless the utilities will always find some specific circumstances that justify taking dollars from some customers and giving those dollars to other customers (while patting themselves on the back).

Nevertheless, I recognize that I have an old-fashioned regulatory philosophy (in which ratepayers pay for what they get), which may be out of touch with today's environment. The balance of my review of these proposals represents my effort to identify the advantages and disadvantages of each proposal.

Q. Please describe the New Community Development Rider ("NCDR") program as proposed by the Company.

A. The NCDR is presented by DLC witness Margot Everett (Statement No. 17) and is shown in the proposed tariff at Rider 19. The program essentially offers a temporary reduction in non-summer base distribution demand charges for both new customers and increased loads for existing customers. The minimum load increase is 10 kW. Customers in Rates GM<25, GM>25, GL and L are eligible to participate; customers in Rate GMH and GLH are apparently ineligible. Discounts to the demand charges begin at 25 percent in 2022 and decline by 500 basis points each year, zeroing out in 2027. The Company offers no projections regarding net changes in load and net changes in distribution rate revenues.[20]

Witness Everett indicates that the objective of the program is ". . . to provide an incentive to attract non-residential customers with beneficial load profiles to the Company's service territory," which would appear to include new customers, customers increasing their loads, and customers who had shut down operations during the pandemic. The Company is apparently attempting to achieve this goal by setting the discount for customers with relatively lower summer peaks is, on average, higher than the discount for strongly summer-peaking customers.

As a technical matter, it is not entirely clear how the incremental demand subject to the rate discount will be determined for customers who qualify as a result of a forecast increase in load.

The Company also indicates that customers who take advantage of this discount may not avail themselves of other rate discounts in the tariff.

Q. Please provide your evaluation of this proposal.

A. The obvious downside to this proposal is that Rider 19 is inequitable and discriminatory, in that new loads/customers are eligible for discounted rates whereas existing customers receiving the identical service are not. Moreover, the Company offers no evidence that the program will actually be effective in attracting net new load, rather than simply providing an opportunity for increased loads to free ride on the discount. Finally, any incremental revenues associated with attracting new (non-free-riding) loads appear to accrue entirely to DLC shareholders.

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[20] I acknowledge that making such estimates would be difficult, in that it would require the Company to identify not only the magnitude of participating loads, but also the "free-rider" eligible loads that the Company would have experienced without the proposed program.

The mitigating factors are (a) any (non-free-riding) new loads will eventually benefit ratepayers in general, (b) the discounts decline and disappear over time,[21] and (c) it does not appear that DLC is requiring any explicit contribution from existing ratepayers to fund this effort.

Thus, if the Commission concludes that the proposal is not unduly discriminatory, the Commission should recognize that the benefits of this proposal will flow primarily to DLC shareholders, at least until the next base rates case. Thus, if the Commission sees merit in this proposal, I recommend that the Commission make it clear that the cost for any rate discounts that would remain in effect for the next base rates case be absorbed by the Company. That is, these discounts should not be recognized as an offset to "present rates" revenue in DLC's next base rates case, if the FPFTY for that case is before 2027.

Q. Please describe the Company's New Business Stimulus Rider ("NBSR").

A. The NBSR is two-year rate discount for new loads at "Vacant Retail Storefronts" located in certain specific geographic areas. The proposed discount is 30 percent of "variable base distribution charges," a term that does not appear to be defined in the tariff but which DLC Witness Kubiak indicates means distribution demand and energy charges. Eligibility as defined in the proposed tariff page is limited to "new small and medium business customers" (neither term appears to be defined in the tariff), although the rider matrix indicates that the eligible classes are GS/GM and GMH (which may include non-business customers). The specific geographical areas of eligibility are Local Neighborhood Commercial ("LNC") districts, Qualified Low-Income Census Tracts ("QCT") and Neighborhood Assistance Program ("NAP") districts.

The intent of the program is to foster redevelopment of business activity in economically disadvantaged neighborhoods, as a response to the business closures from the pandemic.

In support of the program, the Company indicates that 70 percent of survey respondents believed that lower rates would be valuable to new businesses.

[21] In particular, I note that the proposed structure avoids the primary problem with some historical economic development rates in Pennsylvania, namely those in which discounts became permanently entrenched and all but impossible to remove.

Witness Kubiak indicates that the cost of the discounts will be $276,000, based on 540 new customers over a two-year period. Amortized over three years, the annual cost is $92,000.

Q. Please provide your evaluation of the proposed NBSR/Rider No. 25.

A. Like the NCDR, the NBSR is inequitable and discriminatory, in that it results in different rates for new and existing customers who obtain the same service. In addition, I note that the NBSR would appear to depart from the "postage-stamp" principle that generally applies to ratemaking in Pennsylvania, in which rates are uniform within the utility's service territory.

In addition, I am advised by OSBA counsel that the Company's proposal may be in legal conflict with Section 1304 of the Public Utility Code. OSBA counsel advises that it is conducting a legal review of this (and similar proposals elsewhere) and will present its evaluation in its briefs in this matter.

The mitigating factors related to this proposal are (a) it is a well-intentioned effort to redevelop disadvantaged areas (although not so well-intentioned that DLC volunteered any shareholder funds), (b) any load growth may eventually benefit other ratepayers, and (c) the cost impact is relatively small.

Q. Please describe Rider No. 26, the Crisis Recovery Program ("CRP").

A. The CRP is a payment arrangement program for non-residential customers who accumulated an overdue balance during the pandemic. Eligible customers are those in GS/GM and GMH who did not have an overdue balance at February 29, 2020 but currently have a balance, and who can demonstrate that they were impacted by COVID-19. If eligible, customers would have their delinquent balances frozen for six months at the time they are enrolled, and 25 percent of the frozen balance would be forgiven if the customer pays its regular bills in full during the six-month period. The 75 percent balance for the delinquent amount would then be recovered in an 18-month payment arrangement. The window for enrolling in the program would close June 30, 2022.

The Company estimates the cost for the program at $423,000, amortized over three years for an annual cost of $141,000.

Q. Please provide your evaluation of the CRP.

A. The potential benefits of the program relate to the potential for these discounts to allow some customers to stay in business, thereby providing obvious benefits to those participants but also to the utility and eventually to other ratepayers from the increased loads. The program may also benefit the utility by reducing account balances that would otherwise be written off. It is certainly possible that the improved collection rate associated with the payment arrangements will offset the cost of forgiveness. (To my knowledge, DLC has not included this offset in its cost calculations.)

Because this program applies to all customers within the eligible classes, it is not as obviously discriminatory as the other programs. However, it may be seen as inequitable, as customers who have responsibly paid their bills through the pandemic, especially those who were also negatively impacted by the pandemic, are picking up part of the bill for those who did not. In addition, it would appear to be inequitable that Company shareholders make no contribution to the cost for this program, while potentially benefiting from improved collection rates.

Like the other programs, this one is limited to a short time frame and has a relatively low cost. As such, it does not have long-term negative implications.

7. <u>EV Charging Initiatives</u>

Q. Please describe your understanding of the Company's proposals for requiring its ratepayers to invest in and subsidize the development of electric vehicle ("EV") charging infrastructure.

A. In this filing, the Company offers four "pilot" programs designed to encourage and subsidize the development of infrastructure for EV charging, specifically:

1. A "Public, Workplace, and MUD Make-Ready Pilot" ("M-RP);
2. A "Fleet Pilot;"
3. A "Transit Pilot;" and,
4. A Home Charging Pilot ("HCP").

The Company also intends to spend over half a million dollars on customer awareness, education and advisory services (which I believe can be described as "marketing").

Total budgeted cost for these programs in 2022 is $3.0 million in capital and $1.4 million in O&M cost. Ratepayers will be responsible for 100 percent of cost; DLC shareholders will contribute zero. The anticipated benefits from the programs in the form of increased electric distribution loads will initially accrue to utility shareholders but may eventually offset future rates.

The Company indicates that these programs will (a) provide the Company with grid impact data which will allow it to better plan for a transition to a market environment with wide adoption of EVs; (b) leverage the Company's position as a "trusted" source for charging infrastructure; (c) allow the utility to provide new products and services (presumably with financial support from the captive customer base).[22]

Q. What are OSBA's policy positions regarding utility subsidies for EV charging infrastructure?

A. My understanding of OSBA's policy positions are as follows:

1. The OSBA acknowledges that it is conventional wisdom that internal combustion engine ("ICE") vehicles are in the early stages of a significant transition to battery-powered electric vehicles. In OSBA's view, the timing and eventual success of that transition is uncertain.

2. As a general rule, the OSBA believes that achieving societal benefits associated with the transition away from ICE vehicles should generally be the responsibility of government, not electric ratepayers, unless and until the government explicitly assigns that responsibility to utility ratepayers. Raising electric rates to achieve societal aims is an inequitable and regressive method for funding government programs.

[22] DLC Statement No. 8 at 4.

3. Successful transition to an EV-world requires that unregulated entities take primary responsibility for the development of vehicle charging infrastructure. Unregulated entities tend to be more innovative and nimble than utilities for adapting to and accommodating market changes, and utilities are not equipped to make the huge investments necessary to develop all of the necessary infrastructure.

4. Permitting utilities to compete with unregulated firms on unequal terms, such as through subsidies from captive ratepayers, will tend to discourage entry and participation by unregulated firms and may therefore be harmful to widespread development of charging infrastructure.

5. A minimum condition for subsidies for EV charging infrastructure is that subsidies should only be offered where the utility demonstrates *both* that (a) demand for EV charging is growing, and (b) this demand for EV charging infrastructure will not be met by unregulated firms. Citing only to increased demand for EVs is insufficient to justify taxing ratepayers, if the growing demand can adequately be met by unsubsidized unregulated entities, or by direct government intervention. Economic evaluation of these programs should be based on a comparison to what development would occur without the utility intervention, not by simply assuming that the effects of utility subsidies are entirely incremental.

6. It is unclear that electric distribution utilities have any technological or operating advantages relative to unregulated competitors for developing and operating this infrastructure.

7. If the Commission deems that subsidies are appropriate to facilitate the development of a nascent industry, they should be available on a competitively neutral and non-discriminatory basis.

8. In general, any subsidies should be of a temporary nature, designed to address specific problems associated with EV charging infrastructure development, in a way that will not impose long-term burdens on ratepayers. Thus, temporary

rate discounts for new operations are less distortive and burdensome than large capital investments that will burden ratepayer bills for a decade or more.

9. To the extent that the EDC can demonstrate that the usage patterns for EV charging represent off-peak demand and thus contribute less to distribution costs than other loads, this lower cost to serve is better addressed by adopting time-of-use distribution rates which treat all off-peak loads in a non-discriminatory matter, rather than subsidizing one favored industry.

10. To the extent that the Commission determines that ratepayer subsidized investments are appropriate (which the OSBA generally opposes), any risk associated with technological or operational failures should remain with EDC shareholders. The EDC should indemnify ratepayers against any legal and litigation liabilities associated with EV charging infrastructure that appears on the Company's books.

As explained further below, the OSBA concludes that none of the Company's proposed EV charging initiatives are consistent with this policy. In particular, the Company acknowledges that all programs involve utility capital investments that will remain on the utility's books for years, with full funding from ratepayers. Moreover, the OSBA does not believe that there is sufficient evidence demonstrating that the demand for this charging infrastructure cannot be met by unregulated entities without the need for ratepayer subsidies, or that the program is not more appropriately and equitably subsidized by government to achieve public policy objectives.

OSBA therefore recommends that the first three of the proposed EV charging pilot programs be rejected. OSBA takes no position regarding the adoption of the HCP, as it appears to apply only to low-income Residential customers and the costs for this program are presumably assigned to and recovered from Residential customers. However, the OSBA respectfully submits that the Company should indemnify its ratepayers from any insurance, damages and legal costs associated with this in-home Company-owned equipment. It is not reasonable to risk imposing significant legal costs on future ratepayers associated with Company investment in in-home electrical equipment for which it has neither a particular expertise nor reasonable control over the assets.

Q. Please describe the proposed M-RP.

A. As a general rule, on-site "behind-the-meter" investments in electrical equipment at the customer site are the responsibility of the customer. In the M-RP, DLC proposes that it (i.e., captive ratepayers) assume the responsibility for installing this equipment on customer premises. This equipment would be owned by the utility, and DLC would presumably absorb product liability risk for this equipment. Subsidies would be provided for both Level 2 ("L2") and direct current fast charger ("DCFC") charging operations. As I understand it, the program would apply to (a) multi-use dwellings ("MUD"), (b) non-residential workplace locations, (c) public charging stations (including proprietary Tesla outlets). Special efforts will be undertaken in specific geographical locations, namely those designated as "Environment Justice" areas.

As I understand it, this proposal is reflected in a change to the Company's tariff at page 13, Section 6.1 of the rules and regulations. It is not clear to me whether there are any limits on the costs associated with the make-ready infrastructure (except for rebates to L2 stations in EJ areas), or whether those costs will be included in the Company's calculation of the contribution-in-aid-of-construction ("CIAC").[23] The Company's claimed costs for FPFTY 2022 are $900,000 in capital and $147,000 in annual O&M, based on the forecast for 12 L2 sites and 2 DCFC sites.

The Company indicates that this program is generally available on a non-discriminatory basis, and thus will not discourage future investment. Of course, this is a pilot program with constrained participation that may not be continued, and thus the customers who are the quickest may obtain a competitive advantage.

[23] If these costs are included in the CIAC calculation, and if the CIAC calculation reasonably protects existing customers from system expansion costs related to new customers, it should be recognized that this program is not providing subsidies to new customers. In those circumstances, the OSBA's concerns regarding this program are limited to the inequities of providing this service to only one industry, and the risk potential for the equipment on the Company's books.

While the Company claims that the offer is competitively neutral, it will require that eligible customers meet certain conditions that may not apply or be attractive to all interested parties, notably the requirement to subscribe to charging networking services and to provide the Company with charging data through a network vendor.

Q. Please describe the Fleet Pilot.

A. The proposed Fleet Pilot involves the Company directly investing in L2 charging infrastructure for charging commercial vehicle fleets. The Company would both own and maintain the electric distribution assets, the behind-the-meter "make-ready" assets, and the charging stations themselves, although customers are given the option to own the charging equipment. Customers are also given a menu of approved charging equipment from the Company from which they can choose. For this service, the Company proposes a monthly charge per charging port, in addition to the regular distribution rate for the electric service. For those customers who elect to directly purchase Company-supplied chargers, a lower monthly charge applies.

This program is set forth in proposed Tariff Rider No. 24. It is available to the first twelve customers per year in Rates GS/GM, GMH, GL, GLH and L who have a fleet of at least six vehicles.

The forecast FPFTY cost is $729,000 in capital and $201,000 in O&M. It is not clear whether the Company has recognized revenue in its FPFTY cost claim.

Participating customers will be required to enter into a contract of at least 10 years, host at least 4 charging ports, share charging data with DLC, and generally allow DLC reasonable access to maintain its equipment.

It is not clear why this infrastructure cannot be provided by unregulated firms. Moreover, the Company calculates that the revenues generated from charges to customers will cover the full cost. However, that may not be the case for the FPFTY, as revenues appear to fall short of the claimed revenue requirement for that year. Moreover, if this program can be implemented at no net cost to ratepayers, there is no need to include this in the Company's regulated business, since the program should be self-sustaining.

The Company's key advantage is that it faces no risk if the revenues do not materialize as forecast, since the costs can always be shifted to ratepayers. Thus, the proposal is anti-competitive, in that it gives DLC a significant competitive advantage vis-à-vis unregulated firms for providing this infrastructure. It is therefore possible that this proposal will discourage unregulated entities from pursuing this business, and therefore may serve to actually delay the adoption of this technology for vehicle fleets.

Q. Please describe the Transit Pilot.

A. The Transit Pilot is similar to the Fleet Pilot, except that it applies only to providing ratepayer-subsidized infrastructure to the Port Authority of Allegheny County. Specifically, the Company will "install, own and maintain" six 150-kW DCFC charging stations at the Port Authority's East Liberty Garage. The Company proposes to include $984,000 in capital and $100,000 in O&M expense in the revenue requirement claim to be recovered from ratepayers. The charge to the Port Authority for this service appears to be zero.[24] This program will presumably discourage unregulated entities from offering this infrastructure to other government entities across the Commonwealth. Unfortunately, this program has the appearances of an attempt to curry favor with local government authorities at ratepayer expense, particularly since the terms are more attractive to the Port Authority than they are to the other fleet operators.

Q. Please describe the Home Charging Pilot ("HCP").

A. The HCP is a proposed pilot program for Company installation of L2 home charging stations for residential customers. Under this program, the Company will own the L2 charging stations and contribute an additional $500 toward installation ($2,000 for low-income households). The Company proposes that it will recover the direct costs from monthly charges to ratepayers over a five-year period, although the overhead and administrative costs will be passed on to ratepayers. The forecast FPFTY costs are $352,000 in capital and $152,000 in annual O&M. Customers will be required to (a) enter into a 5-year agreement, (b) share charging data with DLC, and (c) maintain active WiFi at the service address.

[24] DLC Statement No. 8 at page 44.

I am advised by counsel that OSBA is concerned about the risks absorbed by the Company associated with owning and operating in-home equipment over which it has no control, in addition to the general risk associated with charging equipment with which the Company has little operational experience. The OSBA respectfully submits that these risks should not be passed to ratepayers and should remain the responsibility of DLC shareholders in the event of accidents, damages and litigation.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 35 years of practical economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 25 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has worked for state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than twenty years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

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

For the **NEW BRUNSWICK PUBLIC INTERVENER,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

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

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

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

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

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

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ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

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

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INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

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

Note: Dates shown reflect submission date for direct testimony.

May 2017

EXHIBIT IEc-2

RDK WORKPAPERS

RDK WP1: Near Replication of DLC ACOSS

RDK WP2: RDK Alternative ACOSS and Revenue Allocation

Workpapers will be transmitted via separate e-mail attachment simultaneous to e-mail service of this document

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024296**
DUQUESNE LIGHT COMPANY	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1 and IEc-2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 30, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3024750**
	:	
Duquesne Light Company	:	
1308(d) Proceeding	:	

CERTIFICATE OF SERVICE

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

Deputy Chief Administrative Law Judge Joel H. Cheskis
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DATE: June 30, 2021

/s/ Sharon E. Webb

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

COMMONWEALTH OF PENNSYLVANIA

July 26, 2021

Deputy Chief Administrative Law Judge Joel H. Cheskis
Administrative Law Judge John Coogan
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. Duquesne Light Company 1308(d) Proceeding / Docket No. R-2021-3024750

Dear Judge Cheskis and Judge Coogan:

Enclosed please find the Rebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No. 1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

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

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

Sincerely,

/s/ Sharon E. Webb

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

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024750**
DUQUESNE LIGHT COMPANY	:	

Rebuttal Testimony and Exhibit of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Non-Residential Class Composition
Cost Allocation
Revenue Allocation
Rate Design
Master-Metered Multifamily Service

Date Served: July 26, 2021

Date Submitted for the Record: ____________________________

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction

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

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

Q. Please describe the purpose of this rebuttal testimony.

A. This rebuttal testimony responds to certain aspects of the direct testimony submitted by the following witnesses:

Glenn A. Watkins and Roger D. Colton, representing the Pennsylvania Office of Consumer Advocate ("OCA") on matters of cost allocation and revenue allocation;

Esyan A. Sakaya, representing the Commission's Bureau of Investigation and Enforcement ("I&E"), on matters of revenue allocation and rate design; and

Teresa Ringenbach, representing Nationwide Energy Partners LLC ("NEP") on matters of electricity service for master-metered multifamily residential dwellings; and

This testimony also updates some of the analysis presented in my direct testimony for additional discovery, which serves to inform this rebuttal.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 provides a brief update of the rate classes under which small and medium businesses take service.
- Section 3 addresses Witness Watkins' and Witness Colton's cost allocation recommendations.
- Section 4 evaluates the revenue allocation and scaleback recommendations of Witnesses Sakaya and Watkins.

- Section 5 addresses the rate design issues raised by Witness Sakaya. It also briefly addresses the Company's Rider 3.

- Section 6 reviews the Company's proposed changes regarding service to master-metered multifamily residences, and the alternative proposal offered by Witness Ringenbach.

2. <u>General Service Rate Classes</u>

Q. Have interrogatory responses received since your direct testimony was submitted provide any more information regarding the nature of customers in the GS/GM and GL rate classes?

A. No. Unfortunately, the Company does not maintain any information regarding the makeup of these classes in terms of SIC or NAICS codes. The Company indicates only that it identifies each new customer in these classes as either commercial or industrial, although neither of those terms appears to be defined in the Company's tariff. Similarly, the Company has not conducted any evaluations of the makeup of those classes.[1] Thus, it is not possible for me to evaluate whether the GS rate class is dominated by small business or whether the class consists of a wide range of other kinds of customers. It is also impossible to evaluate how much of the GS/GM and GL classes consist of government and other non-business customers.

Q. Did interrogatory responses received since your direct testimony was submitted clarify the Company's rationale for retaining a separate electric space heating class for the GM and GL classes?

A. No. As I hypothesized, the Company's primary rationale appears to be inertia, and concern regarding intra-class rate shifts (even if such shifts are cost-based).[2] In fact, the Company acknowledges that it does not rigidly follow tariff specifications when determining

[1] OSBA-I-1, OSBA-I-2.

[2] OSBA-I-11(b),(c),(e).

customer eligibility for these classes, and even one of the sample customer bills it provided indicate that some customers in this class are summer-peaking customers.[3]

The Company's responses do confirm that, for cost allocation purposes, demand-related costs are assigned to these rate classes based on class winter peaks. As I indicated in my direct testimony, this costing method is inconsistent with class rate design for the GMH and GLH classes, in which no demand charges are imposed in winter months.

3. <u>Cost Allocation</u>

Q. Before providing rebuttal testimony, do you have any corrections to your direct testimony as a result of responses to discovery?

A. I do. The Company's response to OSBA-I-35 indicates that the Company's filed ACOSS contains an error in developing the meters cost allocator, which serves to understate the costs assigned to the GM<25kW and GMH<25kW rate classes (and of course overstate the costs for the other rate classes). Unfortunately, the meter count values provided in the response to OSBA-I-35 are substantially at variance with the meter count values in the Company's meters cost workpaper. I also note that the labor cost values in the derivation of meters cost values appear to be understated, as they fail to gross up the cost for paid time unrelated to productive O&M work. I therefore will attempt to resolve this inconsistency through informal discovery and adjust the labor cost values, and I will incorporate any necessary changes in my ACOSS model in surrebuttal testimony, if the impacts are material.

Q. Please summarize Witness Watkins' disagreement with the Company's ACOSS.

A. In the Company's ACOSS, joint use distribution plant costs for the secondary voltage systems are "classified" into customer-related and demand-related components, using a "minimum system" methodology. Primary voltage system assets are classified as entirely demand-related. Witness Watkins disagrees that secondary voltage system assets should have a customer component to costs, and develops an alternative version of the Company's ACOSS using an approach that classifies secondary distribution costs as entirely demand-

[3] OSBA-I-12(b), OSBA-I-3 Attachment 4.

related. Witness Watkins then develops revenue allocation recommendations based on an average of the 100 percent demand ACOSS simulation and the Company's ACOSS.

Q. Is Witness Watkins' view consistent with Commission precedent regarding the classification of electric distribution company ("EDC") distribution plant?

A. I do not believe so. As I explained in my direct testimony, my understanding of Commission precedent involves decisions regarding PPL Electric in 2012 and UGI Electric in 2018, in which the Commission affirmatively approved the classification of EDC distribution plant into both customer and demand components, *for both the primary and secondary voltage systems.*

In making those decisions, the Commission was well aware of the arguments raised by Witness Watkins related to the Bonbright treatise (OCA Statement No. 3 at 14-15), and did not conclude that those remarks justified departing from the minimum system classification methodology.

Q. Please address Witness Watkins' argument that including a customer component in the classification of distribution plant is only necessary if average customer class geographic densities vary between urban and rural areas.

A. I respectfully disagree with Witness Watkins in this matter. Including a customer component in the classification of costs recognizes the economies of scale of interconnecting larger customers. As I indicated in my direct testimony, the distribution system must be sized to both meet the peak demand of customers served "downstream" from each individual asset and to interconnect all customers. Larger customers tend to be less expensive to serve per unit of peak demand, partly for reasons of geographic density, but partly because the cost of extending the distribution system to attach larger customers is not proportional to peak demand. These latter economies exist for both urban and rural areas. If larger customers are more geographically concentrated in urban areas, this implies only that the customer component of costs should be higher under those conditions than it would be if customers were uniformly distributed through the service territory. It does not imply that the customer component of costs should be zero if customers are uniformly distributed.

Q. Please address Witness Watkins' argument that utilities are trending to operating more of their distribution systems at primary voltage.

A. This trend implies that primary voltage systems are increasingly being used to interconnect individual or small customer groups, suggesting that it is increasingly important to recognize scale economies in the primary voltage system by including a customer component of cost for both primary and secondary voltage systems.

Q. Have you reviewed Witness Watkins' ACOSS in detail regarding technical issues?

A. I have not. However, my limited review suggests that Witness Watkins' ACOSS simulation that classifies distribution plant costs as 100 percent demand related includes what I expect is an inadvertent but material error, relating to the allocation of secondary overhead line transformer costs. In the Company's ACOSS, the line transformer costs are classified using a minimum system method, and the demand component of costs is allocated using a demand allocator that is adjusted downward to reflect the peak load carrying capability of the minimum system. In the Schedule GAW-4 ACOSS simulation, it appears that although Witness Watkins rejects the minimum system classification method and sets the customer component for these costs to zero, the simulation continues to use the adjusted demand allocator. Obviously, if there is no minimum system, it is incorrect to adjust the demand allocation factor for the load carrying capability of that minimum system. This explains why Witness Watkins' ACOSS assigns zero costs for secondary overhead line transformers to the RS class.[4] Having participated in numerous proceedings with Witness Watkins, I expect that this error was unintentional. Nevertheless, because the account in question represents some $269 million in gross plant assets, I believe this error has a material impact on Witness Watkins' calculations.

Q. Do you have other concerns regarding Witness Watkins' cost allocation approach?

A. As I explained in my direct testimony, the Company's ACOSS method fails to include a customer component of costs for primary distribution system assets, and it inappropriately

[4] The overhead line transformer costs allocated to Rate RS in Witness Watkins ACOSS at Schedule GAW-4 page 1 are primary system transformer costs.

double-counts certain distribution demands for assigning costs to non-residential customers. Witness Watkins' method retains both of those problems.

Q. What do you conclude regarding Witness Watkins' proposed cost allocation approach?

A. I recommend that the Commission not adopt Witness Watkins' cost allocation approach because it fails to reflect the economies of scale in both the primary and secondary voltage systems for serving larger customers, it is not consistent with Commission precedent, and it contains modeling errors which serve to understate costs associated with providing service to the residential rate classes.

Q. What is Witness Colton's position on cost allocation?

A. Witness Colton concludes that the Company's universal spending for low-income residential customers should not be recovered only from the residential class. Witness Colton proposes that these costs be allocated to and recovered from the various rate classes based on distribution revenues. The impact of this proposal (without concomitant evaluation of the impact of the base rates changes) is shown in Witness Watkins' testimony at Schedule GAW-7.

Q. Can you respond to Witness Colton's argument that assigning the entirety of universal service costs to the residential class makes bills for regular residential customers unaffordable.

A. Whether a particular rate impact is unaffordable is a judgmental matter, which I leave to the Commission. Based on the figures in Witness Watkins' testimony, the savings to the RS class from Witness Colton's proposal would be about $2.40 per month for every customer in the class, a base rate reduction of 4.9 percent. If the savings are applied only to customers who are not in the customer assistance program ("CAP"), the per month savings would be modestly higher. However, based on the figures in Witness Colton's Table 18 for 2021, about 35,000 residential customers are in the CAP, representing about 6.4 percent of the customer base. Assuming that the 6.4 percent value is a reasonable proxy for the share of residential revenues associated with CAP customers, the impact on non-CAP bills would for Rate RS would be about $2.57 per month, or 5.2 percent of base rates.

Q. Witness Colton indicates that the proposed change will have a "*de minimis*" impact on non-residential customers. Can you comment?

A. I suppose the term *de minimis* is as subjective as the term "unaffordable." However, Witness Colton's position regarding what is affordable and what is *de minimis* appear to be internally inconsistent. Witness Colton first indicates that a 5.2 percent base rate impact for Rate RS customers associated with the current allocation method for universal service costs makes those rates unaffordable. Witness Colton then concludes that the base rate impacts on non-residential customers of the OCA universal service proposal, which range from 7.0 percent to 8.0 percent for the distribution voltage classes (excluding lighting), are *de minimis*. It would seem that Witness Colton applies a double standard for affordability.

Q. What are the key conceptual differences in cost recovery policies for universal services?

A. I observe two general philosophies: the insurance model, and the public policy tax model.

The philosophy of recovering all costs from the residential class is based on the argument that only residential customers are eligible for the benefits. A universal service program is a form of insurance, in which residential electric customers are paying premiums to the utility, so that they will be eligible for cash benefits in the event they have an unfortunate turn in their economic circumstances. In this model, it can be argued that it is not unfair that only residential electric customers should get the benefits from the program, because it is only residential electric customers who pay for the program. It can also be argued that these programs are an integral part of utility service, and thus there is less of a need to separately report the charge on the utility bill.

The alternative model is the government policy tax model. This model, as described in some detail by Witness Colton, is based on the argument that there are societal benefits associated with assisting low-income residents. Under this paradigm, all customers should pay because all customers obtain the social benefits. In effect, this form of a low-income programs looks like many other such government programs which provide both individual and societal benefits, and the costs of which are borne by the taxpayers. The government, of course, has a great deal more flexibility as to how and from whom it can recover those costs than does a regulated utility. In this model, providing universal service benefits becomes a public policy expenditure that is not related to providing electric distribution service. As such, charges to customers to recover the costs for this social policy program should be explicitly identified on customer bills.[5]

Q. Of the two models for recovery of utility low-income assistance programs, which do you advocate?

A. My recommendation is that the Commission retain the insurance model, for reasons of cost causation and equity. In this model, customers pay for the benefits for which they are eligible. Residential customers benefit from the insurance, and residential customers pay for that insurance. Non-residential customers are not eligible for that insurance, and they therefore should not pay for the insurance.

While I acknowledge that there are ancillary benefits with policies that assist low-income residents, I observe that using broad societal benefits for allocating utility costs may lead to more confusion and complexity in regulatory matters. If all societal benefits get factored into utility rate cost causation, there will be no end of claimants seeking special treatment. For example, the OSBA could argue that small businesses provide benefits to the economy in the form of job creation, economic dynamism, services for low-income communities, *et cetera, et cetera,* and are therefore deserving of subsidies from the other rate classes. Thus, under Witness Colton's philosophy, the costs for the various economic development and electric vehicle charging programs proffered by DLC in this proceeding would be charged to all rate classes to reflect the alleged social benefits associated with those programs.

In addition, for cost recovery policy, the taxation model cannot easily be implemented across non-residential customers in a way that reflects the social benefits of the universal service programs. In the insurance model, residential customers of DLC pay for the insurance and they benefit from the program if the need arises. Other parties are unaffected. In the tax model, however, the social benefits from the DLC CAP program inure to all residents, businesses and other organizations in DLC's service territory, in a manner that is difficult to quantify. Based on Witness Colton's description of the benefits,

[5] In addition, because it has been a long-standing Commission policy to recover universal service costs only from residential customers, a philosophical change in that policy as recommended by Witness Colton should be explicitly reflect on non-residential customer bills, in the interests of regulatory transparency.

one could reasonably assume that the benefits to businesses are related to employment costs. Thus, a logical recovery method would focus on employment, rather than electricity usage. In contrast, however, Witness Colton proposes to assign costs in a way that imposes a higher unit cost on small business customers than on larger business customers. For example, Witness Colton's proposal for the GS class involves a cost increase of 0.82 cents per kWh. However, for Rate L that value is only 0.15 cents per kWh, and for the largest electricity consumers in Rate HVPS the value is 0.002 cents per kWh. Thus, under Witness Colton's allocation, small businesses are taxed at an energy cost rate many times that of larger businesses, despite the fact that the larger businesses tend to be large employers who presumably benefit from the values to which Witness Colton cites. This is particularly surprising since Witness Colton claims that other jurisdictions that use the taxation model assign costs on a kWh basis, implying equal per-kWh taxes across rate classes.[6]

As to the societal benefits of aid to low-income customers, it is not at all clear that utility programs represent a particularly effective means of assistance for low-income residents, except as it relates to providing an insurance policy to the specific residential customers who benefit from that insurance. In my view, achieving the broad societal benefits from low-income assistance is better accomplished through programs that (a) provide benefits to all low-income customers regardless of their heating fuel, (b) provide benefits to all low-income customers, regardless of whether they enroll in a utility program, (c) are carefully integrated into all other legislated benefits for low-income customers, and (d) are financed in a more progressive manner through taxation policy.

4. <u>Revenue Allocation</u>

Q. What are the positions of the various parties regarding the assignment of the rate increase across the various rate classes ("revenue allocation") in this proceeding?

A. The Company, OCA Witness Watkins and I all prepared separate versions of the ACOSS and developed alternative revenue allocation recommendations at the full $85.8 million proposed base rate increase. In addition, OCA Witness Colton's proposal would shift cost responsibility for the CAP, thereby reducing rates for residential customers and increasing

[6] *"In the states which have universal service programs designed most closely to Pennsylvania's, electric universal service costs are collected on a uniform kWh basis amongst all customer classes."* OCA Statement No. 4 at 62.

them for all other classes. It appears that the two OCA proposals are additive, meaning that the OCA's overall proposed revenue allocation is the sum of those two recommendations. I&E Witness Sakaya does not contest either the Company's ACOSS method or its proposed revenue requirement at the full $85.8 million request, but rather offers modified revenue allocation versions at scaled back increases of $69.8 and $41.0 million. Since there is virtually no chance that the Commission will approve the Company's entire claimed increase (based on my experience in Pennsylvania), Witness Sakaya's scaleback approach should be considered an alternative revenue allocation proposal.

Each witness' revenue allocation proposal is detailed in my workpapers at RDK WP2-R in the "RevAlloc" worksheet. In reviewing these recommendations, I conclude that all of the proposals are at least directionally consistent with the cost allocation results relied upon by the respective witness. Because I do not agree with the cost allocation methodologies used by the Company, Witness Sakaya or Witness Watkins, I recommend against adopting these alternative revenue allocation methods.

However, if the Commission does approve either the Company's or the OCA's cost allocation method, I believe it should consider whether the OCA and I&E proposed revenue allocations violate the principle of rate gradualism. Consider first the OCA revenue allocation (reflecting both the recommendations of both Witness Colton and Witness Watkins), summarized in Table IEc-S1 below:

Table IEc-S1 Summary of OCA Revenue Allocation Proposal			
Class	**$000**	**% Increase**	**Multiple of System Avg**
RS	$24,616	8.4%	0.54
RH	$ 4,788	17.1%	1.10
RA	$ 228	7.1%	0.45
GS	$ 1,731	14.8%	0.95
GM<25	$ 6,783	20.5%	1.31
GM>25	$18,459	26.7%	1.71
GMH<25	$ 818	22.7%	1.46
GMH>25	$ 1,839	31.2%	2.00
GL	$17,232	26.8%	1.72
GLH	$ 2,260	31.4%	2.02
L	$ 5,031	26.9%	1.73
HVPS	$ 20	6.2%	0.40
SE	$ 213	14.3%	0.92
SL	$ 1,423	14.3%	0.92
UMS	$ 232	20.8%	1.34
System	**$85,773**	**15.6%**	**1.00**
Source: RDK WP2-R			

The rightmost column of Table IEc-S1 shows the ratio of the OCA proposed percentage increase in base rates to the systemwide percentage base rate increase. It is not uncommon for the Commission to rely on a multiplier of 1.5 or 2.0 times the system average increase as an upper bound for the average rate increase for any particular class, recognizing that intra-class rate design changes may exacerbate that increase for some customers. As shown, the OCA proposal is at the 2.0 times upper bound for the GMH>25kW and GLH rate classes, and exceeds the 1.5 times limit for three other general service classes. The Commission may wish to consider whether this proposal reasonably reflects the principle of rate gradualism at this time (if it chooses to accept the OCA cost allocation proposal).

Turning to the I&E proposal, I agree with Witness Sakaya that there are several advantages to using an alternative scaleback mechanism to improve progress toward cost-based rates relative to the proposal offered by the Company. First, the primary advantage is that it maintains or even increases progress toward cost-based rates relative to the Company's proposal, whereas the traditional "proportional scaleback" method reduces that progress. Second, from a customer acceptability standpoint, the alternative scaleback approach generally means that no customer class is worse off than under the utility's filed proposal, which may reduce customer complaints and dissatisfaction regarding the regulatory process. Nevertheless, the principle of rate gradualism should continue to apply to the scaled back rates, particularly since the parties to this proceeding all know that some scaleback is virtually certain.

Table IEc-S2 below provides the same values for the I&E revenue allocation proposal after scaleback. In preparing this table, I assumed an overall $55 million increase, and I interpolated between the two alternative approaches, as Witness Sakaya recommends. My calculations are detailed in RDK WP2-R.

Table IEc-S2 Summary of I&E Revenue Allocation Proposal			
Class	**$000**	**% Increase**	**Multiple of System Avg**
RS	$25,485	8.7%	0.87
RH	$ 6,119	21.8%	2.18
RA	$ 660	20.4%	2.04
GS	$ 809	6.9%	0.69
GM<25	$ 792	2.4%	0.24
GM>25	$10,485	15.1%	1.51
GMH<25	--	0.0%	0.99
GMH>25	$ 1,311	22.3%	2.23
GL	$ 4,812	7.5%	0.75
GLH	$ 1,620	22.5%	2.25
L	$ 2,657	14.2%	1.42
HVPS	--	0.0%	0.00
SE	--	0.0%	0.00
SL	--	0.0%	0.00
UMS	$ 251	22.5%	2.25
System	**$55,000**	**10.0%**	**1.00**
Source: RDK WP2-R			

As shown in Table IEc-S2, the I&E proposal would result in rate increases for several classes that are outside the usual bounds for rate gradualism, including proposed increases for the GLH and UMS lighting classes of 22.5 percent compared to a system average increase of 10.0 percent. As it is difficult to believe that the Commission would approve a 2.25 times system average increase for the residential class, it may wish to consider whether it should be similarly resistant to applying that magnitude an increase to non-residential customers.

5. Rate Design Issues

Q. Before addressing rebuttal issues, please comment on the Company's Rider 3, based on responses to IRs received after the due date for direct testimony.

A. In OSBA-I-27, the OSBA requested an explanation for why schools and governmental customers appear to be allowed a 30-day bill payment grace period, while other non-residential customers are given only 15 days. I hate to be a grinch about this, but this tariff provision appears to be unreasonably discriminatory to small and medium businesses, and the Company offers no defense for this policy in its response. This is particularly problematic since, as I indicated earlier, the Company does not categorize its non-residential customers beyond "commercial" and "industrial." I conjecture that it is possible that government customers have lower uncollectible rates, which may therefore offset the advantage of more lax payment terms. However, without evidence supporting this policy, I recommend that this rider be eliminated, and payment terms for government customers should be same as that for other customers in the general service rate classes.

Q. Please comment on I&E Witness Sakaya's recommendations regarding the customer charge for Rate GS/GM and Rate GMH customers at pages 8-11 in I&E Statement No. 3.

A. It appears that Witness Sakaya inadvertently used the incorrect cost values in preparing this analysis. For example, Witness Sakaya reports a $37.46 monthly cost for GM>25kW customers at page 11. In fact, the Company's cost analysis shows a customer cost of $120.81 (which Witness Sakaya correctly reports at page 8), and that value excludes all customer related costs associated with the secondary distribution plant and a variety of A&G costs. My own analysis, including all customer-related costs in the ACOSS, shows a $193.37 per month value using the Company's costing method and $199.69 per month using my costing method. I expect that Witness Sakaya will update the analysis to reflect the correct costs.

6. <u>Master-Metered Multifamily Service</u>

Q. Please provide the background to the issue of master-metered multifamily service in this proceeding.

A. In this proceeding, DLC proposes a modification to its policy regarding the metering requirements for certain multi-family residential properties, to allow for master-metering rather than requiring individual metering in certain circumstances. Nationwide Energy Partners ("NEP") contests the new policy, generally arguing that DLC should be more flexible in allowing multi-family buildings to take master-metered service from the utility and self-meter the individual residents.

Small and medium businesses are affected by this policy, because master-metered residential properties with multiple dwelling units take service under a non-residential general service tariff. Since residential loads tend to have load shapes that are relatively costly to serve, increasing residential loads in master-metered buildings will tend to increase unit costs assigned to non-residential rate classes.

Q. Please describe DLC's current policy on this issue.

A. This issue is addressed in Sections 18 and 41 of the "Rules and Regulations" section of DLC's current tariff:

> 18. REDISTRIBUTION All electric energy shall be consumed by the customer to whom the Company supplies and delivers such energy, except that (1) the customer owning and operating a separate office building, and (2) any other customer who, upon showing that special circumstances exist, obtains the written consent of the Company may redistribute electric energy to tenants of such customer, but only if such tenants are not required to make a specific payment for such energy. This Rule shall not affect any practice undertaken prior to June 1, 1965. See Rule No. 41 for special requirements for residential dwelling units in a building.
>
> . . .
>
> 41. PROHIBITION OF RESIDENTIAL MASTER METERING Each residential dwelling unit in a building must be individually metered by the Company for buildings connected after January 1, 1981. For the purposes of the Rule, a dwelling unit is defined as: One or more rooms for the use of one or more persons as a housekeeping unit with space for eating, living, and sleeping, and permanent provisions for cooking and sanitation. This Rule does not preclude the use of a single meter for the common areas and common

> facilities of a multi-tenant building. This Rule shall not affect any practice undertaken prior to January 1, 1981.

In short, DLC does not provide service to multiple residences or businesses through a single utility meter except where grandfathered or in the case of a separate office building. Because there is no explicit prohibition, I believe that sub-metering in the case of a separate office building is permitted.

Q. What changes has DLC proposed in this case?

A. It is my understanding that in the last DLC base rates proceeding, some parties expressed concern that DLC's requirement that multifamily residences be individually metered by DLC was imposing needless costs on developers/operators of low-income multifamily dwellings, since the electric bills for the tenants in these buildings were typically paid directly by the landlord. I also understand that advocates for low-income customers were concerned that individual metering of multifamily buildings would somehow increase costs for tenants where individual metering is required. This matter was addressed in the settlement of that proceeding. The settlement stipulated:

> Within 180 days of the effective date of rates, Duquesne Light will convene a non-confidential collaborative with all parties to this proceeding, and all interested stakeholders who are developers of multifamily housing within its service territory, to discuss the feasibility of revising its retail tariff to permit master-metering of multifamily housing. Parties to the collaborative will specifically consider:
>
> a. Under what circumstances master-metering would be permitted, and the factors Duquesne Light would require a building owner to meet before approving a master-metering configuration;
>
> b. The impact that any such tariff change would have on low income tenants' ability to continue to afford utility service;
>
> c. The impact of individual customers not utilizing Advanced Metering Infrastructure ("AMI") meters; and
>
> d. The impact that any such change would have on the Company's revenue allocation and the ability to meet its projected revenue requirements.
>
> The parties to the collaborative will make a good faith effort, in coordination with the Company, to develop consensus on the scope of a tariff revision that permits master-metering, taking into consideration all of the foregoing factors. Additional collaborative meetings will be held thereafter, as necessary, but not

less than on an annual basis, in an effort to reach consensus on any issues which remain unresolved after the first collaborative is held. Based on feedback from the collaborative meetings, Duquesne Light will present a proposal regarding master-metering of multifamily housing buildings as a part of its next general base rate case. The treatment of any alleged confidential information during the collaborative will be subject of an agreement of the parties and stakeholders participating in the collaborative.

Pursuant to those stakeholder consultations, the Company proposes to add the following exception to Rule 41:

41.1 RESIDENTIAL MASTER METERING FOR NEW LOW-INCOME SUPPORTIVE HOUSING Notwithstanding anything in Rule No. 41 to the contrary, a single meter may be used for certain multi-tenant premises ("master metering"), where the premises:

1. Is a new service;

2. Is master-metered through entire premises (i.e., no individual tenant meters);

3. Has a minimum of four (4) dwelling units; and

4. Is low-income supportive housing (i.e., housing that is permanently available to low-income tenants where the housing provider is responsible for utility bills).

To be eligible to master-meter a given residential building, in addition to satisfying the other criteria herein, a provider of low-income housing must either:

1. Show that the building is a Public Housing Authority development, or

2. Certify that all tenants are (i) eligible for a Housing Choice Voucher (HCV), available to residents who make 50% or less of the median family income, or (ii) have household incomes equal to or less than 150% of federal poverty guidelines.

Customers permitted to use master metering under this Rule must also, on a continuing basis:

1. Annually certify their on-going conformance to the above criteria; and

2. Participate in each of the Company's applicable energy efficiency, conservation, and/or usage reduction programs.

The Company may retain the customer's security deposit, paid pursuant to Rule No. 5, for the entire duration of the master metering arrangement. If a customer

> using master metering under this Rule fails to comply with any of the foregoing eligibility criteria or ongoing requirements, the Company may require the customer to reconfigure the customer's electrical equipment, at customer expense, to allow the Company to separately meter each dwelling unit.

Q. Has the Company done any analysis of the impact of this proposed change?

A. The Company has made little or no effort to evaluate the impacts of the proposed changes. The Company indicates:

- The Company does not know how many buildings would have qualified for the proposed rate treatment in the past five years. (OSBA-I-8(a))
- The Company does not know how the proposed change in the tariff will affect revenues. (OSBA-I-8(b))
- The Company does not know whether relaxing the individual metering requirement will result in any construction cost savings for developers of low-income housing. (OSBA-I-8(c))
- The Company has no estimate for the future number of buildings and residential units that will qualify for master-metering under the proposed tariff change. (OSBA-I-8(d)).
- The Company has conducted no analysis of the load profile for the residential loads that will be served through general service tariffs under the revised master-metering proposal. (OSBA-I-8(e))
- The Company has no estimate of the incremental EE&C costs that will be assigned to general service customers as a result of the shift of loads from individually-metered residential rates to master-metered non-residential rates. (OSBA-I-8(h))
- The Company does not appear to have any systematic evidence that the electric bills for the eligible properties are being paid in full by the landlord, which was one basis for undertaking this review.

- The Company does not know the number of customers, units or consumption levels for master-metered residential customers currently in its service territory (OSBA-I-8(j)), although it reports to NEP that it has 130 master-metered buildings with one or more residential dwelling units (Nationwide I-4).

- The Company has not performed any studies regarding historical or prospective inter- and intra-class revenue allocation impacts from converting existing services from individually-metered to master-metered buildings. (Nationwide-I-15, 16)

The Company's position regarding its failure to perform the revenue allocation impact analysis specified in the settlement is that because the new requirement only applies to new customers, there is no revenue allocation impact. (DLC Statement No. 6 at 6) This argument makes little sense. New customers are either individually metered or master-metered, and the change in policy will affect where and how the costs and revenues from the new customer will be recognized in future base rates proceedings.

Q. What is OSBA's position regarding this proposal?

A. I am advised by counsel that OSBA concludes that the Company has not met its legal burden to justify the changes that it proposes, and in fact has not fully complied with the settlement terms from the last base rates case by not addressing revenue allocation implications.

However, if the Commission determines that this change should be implemented, I recommend the following tariff modifications to address the cost and revenue allocation inequities. Specifically, I recommend that master-metered multifamily service be included as part of the Residential class for cost allocation and revenue allocation purposes. Because the load shape for multifamily residences should be reasonably similar to that for single family residences, there will be no distortions created by including residential loads in the GS classes. For rate design purposes, DLC would then create a separate sub-class within Rate RS that would apply to master-metered multifamily customers. If it so chose (and if the Commission agreed), the Company could use the relevant GS/GM or GL tariff charges (much in the way that Rider 12 non-residential customers now pay residential tariff charges while being part of the general service class).

Q. What is NEP's proposal?

A. NEP proposes that developers/owners of multi-family residential properties be permitted to purchase electricity supplies and distribution services in bulk for all tenants, and that it be allowed to individually meter and charge tenants for that service at owner-specified rates. NEP indicates that these rates must legally be at or below the regular utility residential rates.[7] I am advised by counsel that OSBA will evaluate this legal position in its briefs as necessary.

Specifically, NEP proposes a revised paragraph 18 and a supplementary paragraph 41.2, shown below:

> 18. REDISTRIBUTION All electric energy shall be consumed by the Customer to whom the Company supplies and delivers such energy, except for (1) any Customer who owns and operates a separate office building, or (2) any Customer who meets the requirements of Rule 41.1 and Rule 41.2 addressing the use of master meters in buildings with at least four (4) residential dwelling units may redistribute electric energy to the tenants of such customer.
>
> 41.2. RESIDENTIAL MASTER METERING IN NON-LOW-INCOME SUPPORTIVE HOUSING Notwithstanding anything in Rule No. 41 to the contrary, the Company shall install, own, operate and maintain a single commercial account ("Master Metering"), and redistribution of electric energy may occur, for multi-tenant premises that include at least four (4) dwelling units where, all of the following criteria are met:
>
> 1. The Customer or its authorized representative verifies in writing that it will comply with the requirements of 66 Pa.C.S. § 1313, price upon resale of public utility services.
>
> 2. The Customer or its authorized representative provides each dwelling unit in the premises with (1) a revenue grade smart meter according to the American National Standards Institute and (2) at least one energy technology for energy efficiency, energy control or demand response.
>
> 3. The tenant in each dwelling unit in the premises will have access to information on their hourly, monthly and annual electric energy usage.
>
> Customers or their authorized representative permitted to use Master Metering under this Rule shall also comply with the following:

[7] See DLC-NEP-I-6(u).

> 1. The Company may request and the Customer or its authorized representative shall provide within 60 days of a request information to certify ongoing compliance with the above criteria: and
>
> The Company shall provide a Commission approved form for Customer or Authorized Representative contact information and required details to ensure proper delivery of such a request; Customers or their authorized representative shall notify Duquesne of their decision to Master Meter under this Rule and shall submit the notice to the Company using a form previously reviewed and approved by the Commission. The Company shall make the form available on its website. The Company shall advise the Customer if the form has any deficiencies within fourteen (14) days of its submission. The Company shall participate in a Commission staff mediation of any unresolved deficiencies should one be requested by the Customer or its authorized representative.

In effect, NEP proposes that it be permitted to go into competition with DLC to provide customer services, EE&C services, metering and billing functions for residents of multi-family buildings.

Q. What arguments does NEP advance in support of this proposal?

A. NEP advances a variety of advantages for the proposal, although many of these arguments appear to be related to the specific services that NEP would offer rather than to the general change in the tariff which would allow both NEP and other parties to compete in this market. These include the following:

1. The Company's limited proposal for new master-metered buildings with low-income residents, which precludes sub-billing of tenants, conflicts with PURPA. This, of course, ignores the Company's claim that the landlords in these buildings pay the tenants' electric bills.[8]

2. Customers get renewable and/or non-carbon energy with no net price premium.

3. Setting the baseline for EE&C programs is somehow easier with master-metering because customer consent requirements are reduced.

4. Allowing property owners to control the installation and/or relocation of electrical equipment in the building will reduce costs and construction delays for the building

[8] DLC Statement No. 6 at 7.

owners/developers compared to having to work with the utility to do so. It may also reduce utility costs passed on to other ratepayers, by reducing the investment required for new customers.

5, NEP argues that master-metering reduces the landlord-tenant problem for EE&C programs, although it is unclear why a landlord would have any increased incentive to invest in conservation when the tenant is paying utility rates to the landlord.

5. Improved availability of EV charging stations, although there is no obvious language in the tariff to guarantee that master-metering will increase EV charging opportunities.

6. Reduced administrative problems for DLC associated with tenant turnover and account changes.

7. Building owners will be better able to participate in wholesale market demand-response programs (possibly resulting in lower-quality service to tenants).

8. Reduced collection risk for utilities, ostensibly because uncollectibles rates are lower for commercial than for residential customers.

9. Lower bills for tenants, if the building owner chooses to pass on the lower cost of commercial versus residential service (which, of course, it has zero incentive to do).

10. NEP asserts that it “has no reason to believe” that adopting its proposal would result in a significant shift in inter- or intra-class revenue allocations between now and the next DLC base rates case. The assertion, of course, provides zero evidence for the contention, and ignores the fact that changing the redistribution policy now will likely have long-term rather than short-term revenue allocation implications.

Q. Do you have any additional concerns regarding the NEP proposal beyond those related to the DLC proposal?

A. I have the following concerns:

Rate Class Definitions: The general rate design issue regarding the NEP proposal is that electric rates in Pennsylvania are differentiated between residential service and non-residential service due to the different requirements of the customer classes, the different protections offered to residential and non-residential customers, and the different costs to serve. Expanding the loophole by which some residential customers are served through general service rates is arguably inconsistent with a basic regulatory policy standard in Pennsylvania of having different residential and non-residential rates. I am advised by counsel that OSBA will address this legal issue in its briefs as necessary.

Class Cost Impacts: NEP's proposal will presumably result in a prospective shift of both new and current individual residential accounts to non-residential general service accounts, relative to continuing the status quo. The magnitude of that shift is unknown, and NEP offers no estimate. However, this will mix more residential load shapes into the non-residential classes' load, which will generally have a negative impact on their load factors, particularly for the medium and larger general service customers (who have better load factors in general). The magnitude of this impact is unknown, and NEP offers no estimate.

Revenue Allocation: As discussed above, the Company somehow believes it is not necessary for it to evaluate revenue allocation impacts of the Company's proposed change. NEP reaches a similar conclusion, despite the fact that the settlement in the last base rates case explicitly agreed that a revenue allocation impact was a necessary part of any rate change.

Customer Choice: Individual residential customers in the NEP scheme will not have a choice of suppliers. While this effect may be the same as that for customers currently in the "special case" situations in DLC's tariff where master-metering is allowed, NEP proposes what could be a significant expansion of tenants taking service through a master meter. This, NEP's proposal would expand the problem, possibly materially. Similarly, individual tenants will not have the opportunity for time-of-use rates, unless such rates are offered by the landlord.

Unregulated Rates: The rates paid by tenants are not regulated, except for the cap. It is also unknown how effective or diligent NEP and other owner/developers would be in ensuring that rates are always below the cap. Whether the NEP proposal is permitted under Pennsylvania legislation and the Commission's regulations are legal issues for OSBA counsel. NEP indicates that it provides these services elsewhere in Pennsylvania, although that appears to be limited to five buildings in PECO's service territory with 63 tenants.[9]

Universal Service Charges: By taking DLC service through general service rates, the developers/landlords would avoid contributing to universal service (customer assistance program, "CAP") costs (at least under the current DLC policy). Of course, there does not appear to be anything to stop developers/landlords from implicitly including the cost of universal service charges in their bills to residents, since those costs are an integral (albeit hidden) part of DLC's residential rates.

Universal Service Eligibility: Customers taking service through the master-meter are not eligible for universal service, either in DLC's proposal or in NEP's proposal. NEP indicates that it does not serve "low-income properties."[10] NEP also argues that the discount it proposes for its own service ($2 per month) is similar to the CAP discount.

Utility EE&C: Having more residential customers taking service through commercial rates may complicate the utility's ability to meet the legislative requirement that each class pay for its own EE&C programs. CSP's serving residential customers will presumably also be engaged in projects for these general service customers, and will need to track costs separately.

Consumer Protections: NEP indicates that it would attempt to adhere to Pennsylvania rules regarding disconnection for non-payment, but it appears that the actual rules are those established by the property owner and NEP and include the potential for eviction.[11]

Q. What, then, do you recommend regarding the NEP proposal?

---

[9] See DLC-NEP-I-1,2,15.

[10] See DLC-NEP-I-25, I-6(o),(p).

[11] See DLC-NEP-I-6(i)

A. For the reasons detailed above, I recommend that the NEP proposal be rejected. However, if the Commission determines that there is merit in the NEP proposal, I offer the same recommendation regarding cost and revenue allocation as I do for the DLC proposal. That is, master-metered multifamily customers should be treated as Rate RS customers for the purposes of cost and revenue allocation. In that way, small business customers will not be negatively impacted by NEP's proposal, which should relate only to residential class impacts.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R1

RDK WORKPAPERS

RDK WP2-R: RDK ACOSS with Supplemental Calculations

Workpapers will be transmitted via separate e-mail attachment simultaneous to e-mail service of this document

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024750**
DUQUESNE LIGHT COMPANY	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit IEc-R1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 26, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3024750**
	:	
Duquesne Light Company	:	
1308(d) Proceeding	:	

CERTIFICATE OF SERVICE

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

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DATE: July 26, 2021

/s/ Sharon E. Webb

____

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

COMMONWEALTH OF PENNSYLVANIA

August 10, 2021

Deputy Chief Administrative Law Judge Joel H. Cheskis
Administrative Law Judge John Coogan
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. Duquesne Light Company 1308(d) Proceeding / Docket No. R-2021-3024750

Dear Judge Cheskis and Judge Coogan:

Enclosed please find the Surrebuttal Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1-S, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

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

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

Sincerely,

/s/ Sharon E. Webb

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

Enclosures
cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

Office of Small Business Advocate
Forum Place | 555 Walnut Street, 1st Floor | Harrisburg, PA 17101 | 717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024750**
DUQUESNE LIGHT COMPANY	:	

Surrebuttal Testimony and Exhibit of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design
Small Business Initiatives
Electric Vehicle Subsidies

Date Served: August 10, 2021

Date Submitted for the Record: ____________________________

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction

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

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

Q. Please describe the purpose of this rebuttal testimony.

A. This surrebuttal testimony responds to certain aspects of the direct testimony submitted by the following witnesses:

Howard S. Gorman, representing the Duquesne Light Company ("DLC" or "the Company") and Glenn A. Watkins representing the Pennsylvania Office of Consumer Advocate ("OCA") on matters of cost allocation;

Company Witness David B. Ogden relating to revenue allocation and rate design issues;

Company Witnesses Margot C. Everett and Krysia Kubiak relating to the various small business initiatives proposed by the Company in this proceeding;

Matthew Deal, representing ChargePoint, Inc. ("ChargePoint") and Company Witness Sarah J. Olexsak regarding subsidy programs for electric vehicle ("EV") charging infrastructure.

Q. How is the balance of your testimony organized?

A. This testimony is organized by subject matter. Issues related to cost allocation, revenue allocation, rate design, small business initiatives and subsidies for electric vehicle charging ("EV") infrastructure are addressed in Sections 2 through 6 respectively.

2. Cost Allocation

Q. In response to your direct testimony, Witness Gorman asserts that the Commission's decision in the Company's last base rates case provides more recent precedent in support of the Company's methodology for its allocated cost of service study

("ACOSS"), as compared to the decisions to which you cite in your direct testimony. Please respond.

A. Based on my review of the settlement document, the recommended decision, and the Commission's order at Docket Nos. R-2018-3000124/3000829, I find no Commission approval of the Company's cost allocation methodology. Based on this record, I conclude (as a non-lawyer) that the revenue allocation settlement in the last case was a "black box" settlement, and it was not based on any explicit cost allocation methodology. This is common practice in Pennsylvania. In order to achieve a settlement of revenue allocation and rate design issues, parties to base rates cases consider the cost allocation and revenue allocation recommendations of all of the witnesses, and they craft a compromise that is not based on any specific costing methodology. If it were necessary to identify a specific cost allocation methodology in a settlement, few electric and gas industry base rates cases would settle. As OSBA indicated in its statement of support in the Company's last base rates case, the revenue allocation " . . . Settlement increases for the small business classes reflect a compromise among the parties, particularly with respect to the litigation positions of OSBA and OCA"[1]

Thus, what the Commission did in Matter R-2018-2000124/3000829 was approve a compromise revenue allocation settlement that was not tied to any particular cost allocation methodology. It did not approve a cost allocation methodology. While I am not an attorney, I doubt this approval qualifies as precedent.

Moreover, Witness Gorman's attempt to use prior proceeding settlements as precedent will likely serve to reduce parties' interest in settling base rates proceedings. This conflicts with the Commission's practice to encourage settlements, and it will likely just encourage more extended litigation. I encourage the Commission to emphatically reject Witness Gorman's attempt to use black box settlement provisions as precedent for future cases.

[1] Recommended Decision, Administrative Law Judge Katrina L. Dunderdale, Docket No. R-2018-3000124, October 10, 2018, at 67

Q. Witness Gorman also indicates, in support of the Company's methodology, that the current approach has been used for many years and OSBA has not heretofore taken exception to that method. Please respond.

A. OSBA has not yet taken a position regarding the appropriate cost allocation methodology in this proceeding. I am advised by OSBA counsel that it will do so in its briefs. The Company's attorneys will presumably be free at that time to address the issue of historical consistency at the appropriate time, and to argue that no party may ever change its position regarding a technical matter of regulatory policy.

I was retained by OSBA to provide an independent evaluation of the Company's cost allocation methodology, and I have done so. I was not a participant in earlier DLC base rates proceedings, and thus Witness Gorman's complaint is irrelevant to my testimony.

In respect of Witness Gorman's argument that the Company has long-used the methodology offered in this proceeding, I observe that PPL Electric used a similar approach of classifying only the secondary voltage system into customer and demand components. It then determined in the PPL Electric 2010 (Docket No. R-2010-2161694) proceeding that it was more accurate to classify both primary and secondary voltage systems into customer and demand components. The Commission agreed. Thus, at least from the perspective of Commission precedent, a long-established practice of classifying primary distribution system assets as entirely demand related can reasonably be modified.

Q. Still at a general level, Witness Watkins observes that your direct testimony advocated a cost allocation methodology based on precedent, rather than developing a methodology based on the specific attributes of the DLC distribution system. Please respond.

A. I respectfully disagree. First, cost allocation methods differ between utilities and regulatory jurisdictions for reasons beyond the specific nature of a particular service territory. For the classification of both electric and gas distribution plant, the choice of classification methods is much more dependent on cost allocation philosophy than it is on the specifics of any particular utility. For both gas and electric distribution utilities, the choice of classification methodology has an enormous impact on the allocation of costs, far more than could be justified by differences in individual distribution systems. Thus, at least in my experience, it is common for regulators to maintain reasonable consistency in basic cost allocation philosophy across utilities within the jurisdiction. In Pennsylvania, for the gas distribution industry, that has generally resulted in policies which reject the classification of gas mains costs into customer and demand components. For the electric industry, the jurisdictional policy favors a customer-demand classification approach.

Moreover, It is certainly not difficult to find examples in the gas industry where witnesses representing the OCA and I&E have cited to Commission precedent in support of their proposed methodology for excluding a customer component of costs. In fact, the Commission itself has cited to precedent across companies in support of its regulatory findings.[2]

Second, regardless of the choice of a classification method, the underlying analysis must necessarily reflect the specifics of the utility. The utility-specific factors include the magnitude of booked costs by plant account, the utility and rate class relative loads and load shapes, and the investment relationship between minimum-sized system assets and higher capacity equipment. All of these factors are reflected in my analysis.

Third, regarding my concerns about the allocation of underground system costs, I acknowledged and in fact commended the Company for attempting to be more precise in segregating and allocating its assets. My concerns, however, are that the end result is an allocation of plant that is not supported by any detailed evidence, it defies common sense and it is inconsistent with the results at other Pennsylvania EDCs. As I explained in my direct testimony and further below, I believe these results reflect not differences in the DLC system, but unsupported or dubious assumptions in the cost allocation modelling.

Q. In his rebuttal testimony, did Company Witness Gorman modify the ACOSS?

A. Yes, but the modifications were minimal, and had no material impact on allocated cost. The primary change was to modify class revenues at present rates in the updated ACOSS.

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[2] See, for example, Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3018835, Order entered on February 19, 2021, at 213. *"Based on our prior determinations on our preferred ACCOSS in natural gas proceedings, we believe that the P&A ACCOSS is best suited in this proceeding."*

I updated my "near replication" analysis in RDK WP1-S, which is being circulated with this testimony.

Q. Let's turn to the issue of classifying primary distribution system plant. Witness Gorman indicates that developing a minimum system calculation for primary distribution system plant is meaningless. Can you respond?

A. I agree with Witness Gorman that any standard method for classifying distribution system plant is imperfect and is at best an estimate. I would also agree that it is high time for the industry to begin to develop costing methodologies for distribution plant that are more precise than the traditional methods for assigning distribution plant across rate classes, to better reflect both the costs associated with expanding capacity and extending the system to interconnect customers.

Nevertheless, until better methods are developed, the Commission, as well as experts for several other Pennsylvania EDCs (West Penn Power, Penn Power, UGI Electric, PPL Electric) have been able to develop minimum system classification factors for primary system plant. I respectfully disagree that the Commission's preferred method is meaningless.

Q. Witness Gorman indicates that if a minimum system calculation were to be developed, the values you use in your direct testimony have too high a customer component. Can you respond?

A. I requested the information necessary to include a minimum system classification for primary distribution system assets in OSBA-I-36, and the Company declined to provide them. It is a little disingenuous for Witness Gorman to now criticize my estimates. Moreover, as shown in Table IEc-S1 below, the parameters that I use for classifying distribution plant have a lower customer component than the parameters used at UGI Electric and PPL Electric where the Commission has explicitly approved this methodology, and well below those at other large Pennsylvania EDCs. The parameters are also well below those used by West Penn and Penn Power in their most recent base rates proceeding, although these values were not explicitly approved by the Commission because the cases were settled.

Table IEc-S1 Classification of Joint Use Distribution Plant: Primary Voltage System Customer Component of Costs						
	DLC Proposed	**RDK Proposed**	**PPL Electric**	**UGI Electric**	**West Penn**	**Penn Power**
364: Poles	0%	47%	51%	57%	82%	81%
365: OH Conductors	0%	47%	48%	36%	92%	90%
366: UG Conduit	0%	20%	81%	24%	NM	NM
367: UG Conductors	0%	20%	81%	100%	87%	85%
Sub-Totals	**0%**	**37%**	**59%**	**45%**	**88%**	**88%**
Note: Underground conduit plant at West Penn and Penn Power is minimal. Source: RDK Records, RDK WP1-S						

Q. Both Witness Gorman and Witness Watkins make reference to the NARUC Electric Utility Cost Allocation Manual ("Manual").[3] What does the Manual indicate regarding the classification of electric distribution plant?

A. The Manual generally indicates that a typical functionalization and classification of joint use distribution plant (poles, conductors, conduit and line transformers) would include segregation into primary and secondary voltage categories, and classification into demand and customer components (page 89). For classifying joint use plant, the Manual posits the "minimum size" (or minimum system) approach and the "minimum intercept" approach. Both of these methods rely on the idea that the customer component of distribution plant costs is based on the cost of either the smallest equipment in use on the system or on the statistically estimated cost of equipment with zero load carrying capability. Conceptually, these models are very similar.

If a minimum system method is used, the Manual is silent as to whether the classification analysis should be applied separately to both primary and secondary voltage. If the minimum intercept method is used, the Manual specifically indicates that a minimum intercept analysis should be conducted separately for primary voltage and secondary

[3] Witness Watkins in particular objects to certain general statements that I made in my direct testimony regarding the dictates of the Manual. While I do not believe my statements are inaccurate, this surrebuttal testimony provides a more careful description of the Manual.

voltage systems for Accounts 365 (Overhead Conductors) and Accounts 366 and 367 (Underground Conductors and Conduit)"[4] Given the conceptual similarities between the minimum system and minimum intercept approaches, it is not unreasonable to conclude that the Manual would apply separate minimum system analyses to primary and secondary voltage systems. In the alternative, it could reasonably be inferred that the Manual would apply the minimum system analysis to the combined primary and secondary systems.

My experience in Pennsylvania is consistent with both of those interpretations. UGI Electric and PPL Electric use separate minimum system analyses for primary and secondary systems. West Penn Power and Penn Power apply the minimum system analysis to the combined systems.

Q. In your direct testimony, you expressed concern about potential double-counting of customer loads for the allocation of overhead and underground conductors and conduit. Please explain generally why you have this concern.

A. In my experience, ACOSS analyses generally reflect that the distribution plant cost to serve larger customers per unit of peak demand is no higher, and usually lower, than that to serve smaller customers. In DLC's ACOSS, the reverse is true.

Table IEc-S2 below compares the DLC's unit cost to serve customers by class with ACOSS analyses at UGI Electric and PPL Electric, both based on demand costs and based on total costs. (I have limited this analysis to the primary voltage system, as that represents a significant majority of DLC's plant costs and represents the primary area of disagreement.) As shown, DLC shows the unusual pattern that large customers are substantially more expensive to serve than smaller customers per unit of peak demand. That is, as customers get bigger, the unit cost gets higher, implying that there are diseconomies of scale. This result is partly due to the lack of a customer component for distribution costs, but even if customer-related costs are excluded, as shown in Table IEc-S2, the pattern at DLC is unusual and counter-intuitive. At DLC, the plant costs for primary distribution assets for

[4] Re Account 365, the Manual indicates, "Total primary or secondary dollars in the account . . . are assigned to customer and demand components based on conductor investment ratio." Re Accounts 366 and 367, the Manual indicates, "If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each."

the medium and larger general service customers are higher than that for both residential and small general service, while the reverse is true for both PPL Electric and UGI Electric.

Moreover, while the DLC results are relatively favorable for its residential customers, that same result does not apply to small general service customers. Thus, the difference at DLC is not due to favorable treatment for small customers, it is due to favorable treatment for residential customers only.

Table IEc-S2
Primary System Distribution Plant Costs per Unit of NCP Demand

	Residential	**GS/GS-1/GS-1**	**GM/GS-4/GS-3**	**GL/LP/L**
DLC (Demand/Total)	$433	$670	$677	$709
UGI Elec. Demand Only	$259	$259	$259	$259
PPL Elec. Demand Only	$137	$137	$137	$137
UGI Electric Total	$575	$794	$315	$283
PPL Electric Total	$368	$457	$153	$137

Gross Plant costs for primary voltage system costs in accounts 364 to 367.
Source: RDK Records, RDK WP1-S, "UGI PPL" worksheet

Q. Based on the additional discovery responses you received, please update your understanding of the Company's methodology for functionalizing, classifying and allocating primary and secondary voltage system plant costs.

A. The Company's method is the following:

- Plant costs are sub-functionalized between primary and secondary voltage systemsbased primarily on a review of purchases between 1999 and 2019.[5] A significant majority (73 percent) of joint use distribution costs (Accounts 362-368) are deemed to be related to the primary voltage system.

- The Company segregates the costs for some plant equipment between its downtown network and its non-network systems. The entire downtown network is deemed to be non-residential, but it represents under 3 percent of distribution plant costs for

[5] DLC Statement No. 15 at 19.

those accounts that are segregated. Cost segregation is undertaken for substations (Account 362), underground conductors and conduit (366, 367), and line transformers (368). Non-network costs in accounts 366 to 368 (underground conductors/conduit and line transformers) are further segregated into underground residential developments ("URD") and "Radial" systems.[6] The URD system serves only residential customers; the Radial system serves primarily non-residential customers. As Witness Watkins correctly points out, this sub-functionalization is essentially an effort to directly assign underground system costs between residential and non-residential classes. No similar effort is made to directly assign overhead system costs.

- As discussed above an in my direct testimony, primary voltage system costs are assumed to be entirely related to non-coincident peak ("NCP") demand; secondary voltage system costs are classified using a minimum system method.

- The Company develops separate NCP demand allocation factors for its network, non-network, URD and Radial systems. The network and non-network demand allocators sum to the total system NCP. Allocators for the URD and Radial systems are intended to reflect the usage of the underground systems.

Q. Given this methodology, why does the Company's allocation produce results that are counter-intuitive and at odds with the results from other Pennsylvania EDCs.

A. This unusual pattern results primarily from three factors:

- First, a disproportionate share of underground system costs is "directly assigned" to the non-residential classes. For the primary voltage system, the non-residential classes are assigned 85 percent of costs, while representing only 53 percent of distribution system NCP demand.[7]

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[6] Line transformer costs are first segregated between overhead and underground assets, and the underground assets are further segregated into network, URD, and Radial systems.

[7] My more detailed calculations regarding these figures are shown in RDK WP1-S in the "UGI PPL" worksheet.

- Second, despite being assigned a disproportionate share of underground system costs, non-residential customers are assigned a full share of overhead system costs.

- Third, the Company adjusts the allocator for the Radial system underground plant costs to exclude residential customers not served by those assets. However, it makes no similar adjustment for non-residential customers and assumes all non-residential loads are served by these assets.

Q. Please explain how the Company segregates its underground conductor and conduit costs between the downtown network, radial and URD cost categories for ACOSS purposes.

A. These values represent engineering estimates, and do not appear to be based on any contemporaneous accounting data or on any available detailed studies. OSBA requested the details for this cost segregation in OSBA-I-33, but no details were provided. Given the large cost impact that this "direct assignment" approach has on allocated cost, I conclude that a fundamental aspect of the Company's ACOSS results is unsupported. Without this support, I conclude that the approach used in my direct testimony is superior, because it follows the common practice of allocating all demand-based costs using NCP demands.

Q. Does the Company explain why it does not make an adjustment to overhead system costs to reflect the higher assignment of underground system costs to non-residential customers?

A. The Company's position appears to be that every customer uses the overhead system equally, and that non-residential customers disproportionately use the underground systems. I respectfully disagree. If, indeed, non-residential customers use a disproportionate share of the underground system, that reduces the need for overhead system costs. In effect, if the underground system were to be replaced by overhead system assets, the Company's method would have us believe that non-residential customers are disproportionately responsible for overhead system costs, beyond that which would be assigned using a demand allocator.

Q. Do you have any other concerns regarding the Company's allocation of distribution plant assets?

A. Yes. The Company's "direct assignment" approach for cost allocation is imperfect, in that some residential customers are served by the Radial system. The Company assumes that 97.5 percent of residential loads are not served from the Radial system. When asked to provide details for this estimate, the Company indicates only that it relied on engineering estimates, and it provided no supporting detail (OSBA-I-33(c)). Moreover, unlike the adjustment for residential customers, the Company assumes that all non-residential load is served by underground Radial system assets. This assumption is not reasonable. It is likely that a significant share of non-residential load does not use underground assets. When queried for the basis for this assumption, the Company offers no explanation other than it did not make an adjustment for non-residential customers (OSBA-I-33(c)).

Q. At page 5 of his rebuttal testimony, Witness Watkins observes that in making your modifications to demand allocators to reflect the concerns discussed above, you failed to adjust the classification of secondary URD costs to be consistent with your thesis. Please respond.

A. Witness Watkins is correct. It was my intent to adjust the URD allocation factors to be consistent with the treatment of overhead and underground radial costs, and thus I should have adjusted the classification factor in those allocators. In fact, Mr. Watkins critique applies both to my treatment of primary and secondary URD costs, because I include a customer component in my primary system voltage allocations. I therefore modified my classification factors for URD assets to be consistent with those used for the Radial system.

In reviewing my calculations based on Witness Watkins calculations, I also observed that in developing my demand allocation factors for underground Radial and URD systems, I based those allocators on total NCP demand. Because these systems do not include the downtown network, I adjusted my allocators to exclude downtown network demands.

The former correction serves to increase costs assigned to non-residential customers; the latter correction modestly reduces costs assigned to non-residential customers.

Q. Do you have any other corrections to your ACOSS analysis?

A. Yes. I observe that the Company sub-functionalizes its substation costs into network and non-network categories, with network customers representing about 2.5 percent of system costs for that account and 2.6 percent of system NCP demand. However, the Company allocates the non-network costs based on total system NCP demand, rather than non-network demands. In effective, network demands are counted twice; first for network costs and then for non-network costs. I have corrected for this inconsistency in my surrebuttal ACOSS (RDK WP2-S).

Q. What are the net impacts of the revisions to your ACOSS?

A. To a large extent, the modifications that I made to my direct testimony ACOSS tend to offset, resulting in only modest changes in allocated cost. Table IEc-S2 below compares class rates of return at present rates in my direct testimony with the updated values in RDK WP2-S. The table includes the Company's updated values as well.

Table IEc-2
Comparative Cost Allocation Results
Class Rates of Return at Present Rates

Class	DLC Rebuttal	RDK Direct	RDK Surrebuttal
RS	5.4%	2.6%	2.6%
RH	2.5%	1.2%	1.1%
RA	3.3%	1.5%	1.4%
GS	5.8%	2.1%	2.1%
GM<25	6.9%	9.2%	9.0%
GM>25	4.7%	10.2%	10.0%
GMH<25	5.5%	6.5%	6.3%
GMH>25	3.2%	7.6%	7.5%
GL	6.2%	12.6%	12.8%
GLH	2.7%	6.2%	7.0%
L	5.2%	12.7%	12.5%
HVPS	739%	672%	671%
SE	11.5%	22.7%	21.8%
SL	15.1%	16.4%	16.4%
UMS	2.4%	-1.8%	-1.8%
System	**5.4%**	**5.4%**	**5.4%**

Source: DLC Exhibit 6-1(R)), RDK WP2, RDK WP2-S

3. Revenue Allocation

Q. Witness Ogden indicates, "The Company's proposed revenue allocation is impartial and does not favor any rate class or customer group, whereas the revenue allocations proposed by OCA and OSBA each favor their respective customer groups, at the expense of other customer groups." Please respond.

A. It is unfortunate that Witness Ogden feels the need to smear the integrity of Witness Watkins and me. I believe that Witness Watkins and I both prepared cost allocation analyses in good faith, and we developed revenue allocation proposals based on that analysis. Similarly, we both recognize the limits to cost allocation analyses, and we both recognize that there are disagreements among experts. While I believe the Company's cost allocation analysis is similarly based on principle, there is no denying that the method used by the Company is not consistent with established Commission precedent, and it produces the highly unusual result that the Company's implied cost to provide primary voltage distribution service to larger customers is more expensive per unit of peak demand than to provide that service to smaller customers. There is nothing about the Company's costing method that implies it is any more impartial than the analyses put forward by Mr. Watkins and me.

Q. Witness Ogden indicates that the Company considered three different measures of progress toward cost-based rates in developing its revised rebuttal revenue allocation, in response to your direct testimony. Please comment.

A. Consideration of all three metrics is far superior to the Commission's traditional practice of relying solely on the badly flawed indexed rate of return metric. The Company is to be commended.

Q. Did the Company update its revenue allocation proposal in rebuttal?

A. Yes it did, although the changes were relatively modest.

Q. What is your assessment of the Company's rebuttal revenue allocation proposal?

A. Like its direct case, I believe the Company's revised revenue allocation proposal is reasonably consistent with its cost allocation methodology, and reasonably reflects the principle of rate gradualism. I disagree with it only in that it relies on a cost allocation methodology that is not consistent with Commission precedent and produces results at variance with those of other Pennsylvania EDCs.

Q. In light of the changes to your ACOSS, did you develop an alternative revenue allocation proposal?

A. I did, as shown in RDK WP2-S. In so doing, I used the same calculation methodology as detailed in my direct testimony. Because the cost allocation results are little changed, so too is my proposed revenue allocation. Table IEc-S3 below compares my revenue allocation analyses.

Table IEc-S3
Comparative Revenue Allocation Proposals

Class	DLC Rebuttal		RDK Direct		RDK Surrebuttal	
	$000	%	$000	%	$000	%
RS	$40,889	14.3%	$68,297	23.4%	$68,057	23.3%
RH	$ 6,176	22.5%	$ 6,554	23.4%	$ 6,532	23.3%
RA	$ 711	22.5%	$ 755	23.4%	$ 752	23.3%
GS	$ 1,521	14.2%	$ 2,729	23.4%	$ 2,725	23.3%
GM<25	$ 4,983	15.7%	$ 861	2.6%	$ 917	2.8%
GM>25	$13,065	17.3%	$ 1,804	2.6%	$ 1,923	2.8%
GMH<25	$ 555	16.2%	$ 427	12.1%	$ 466	12.9%
GMH>25	$ 1,300	22.3%	$ 365	6.6%	$ 435	7.4%
GL	$ 9,928	15.8%	$ 1,673	2.6%	$ 1,781	2.8%
GLH	$ 1,676	22.5%	$ 1,256	17.8%	$ 836	11.6%
L	$ 3,889	18.3%	$ 485	2.6%	$ 516	2.8%
HVPS	$ 0	0.0%	$ 8	2.6%	$ 9	2.8%
SE	$ 76	5.4%	$ 39	2.6%	$ 41	2.8%
SL	$ 511	5.2%	$ 259	2.6%	$ 276	2.8%
UMS	$ 246	22.5%	$ 261	23.4%	$ 260	23.3%
System	**$85,528**	**15.5%**	**$85,773**	**15.6%**	**$85,526**	**15.5%**

Source: Table DBO-1(R); RDK WP1-S; RDK WP2-S

Q. Please address Witness Ogden's proposal for a revenue allocation scaleback in the event that the Commission modifies the overall proposed revenue requirement in this proceeding.

A. As I understand it, Witness Ogden proposes that the Commission first issue its decision on the revenue requirement, on the cost allocation methodology, and on the revenue allocation at the originally proposed revenue requirement. In the compliance phase of the process, the Company would then prepare a revised ACOSS based on the new revenue requirement and the approved ACOSS methodology. The Company would then develop a revenue scaleback using the approved revenue allocation, with some combination of proportional reductions and judgmental adjustments. (The Company would presumably include consideration of the revised ACOSS, since there would be no reason other than revenue allocation to create the new ACOSS in the compliance phase.) Witness Ogden does not contemplate any involvement of the other parties to this proceeding in the compliance process. This failure is particularly problematic, as there is potential for disagreement regarding cost allocation, and there is almost certain to be disagreement regarding the unspecified judgmental criteria the Company proposes to apply to revenue allocation in this process.

As a theoretical matter, I generally agree with Witness Ogden that a revenue allocation scaleback would be much more accurate if undertaken after the Commission's decisions on revenue requirement and cost allocation methodology are known. Procedurally, however, I do not know how that process would work without either (a) denying participants a right to participate in the revised revenue allocation or (b) incurring a significant time delay in the process. If these issues can be resolved, I would support Witness Ogden's proposal. However, if they cannot, the proportional scaleback approach has certain advantages. First, to the extent the full requirement revenue allocation sets upper bounds on rates as a multiple of system average, a proportional scaleback retains those bounds. Thus, for example, if the Commission approves a maximum increase for a particular class of 1.5 times the system average at the full revenue requirement, that limit will generally be automatically maintained with a proportional scaleback.[8] Second, with a proportional scaleback, all classes that were assigned increases at the full requirement benefit from an overall reduction. Third, the proportional scaleback is arithmetically simple, and thus is typically not contested in the compliance process.

The procedural problems can also be resolved by developing an alternative arithmetic scaleback approach in the evidentiary portion of the proceedings. As a conceptual matter, I believe that such an approach can be reasonable. However, as I indicated in my rebuttal testimony, the scaleback proposal should be subject to the same considerations as the revenue allocation at the full revenue requirement, namely the progress toward cost-based rates and consideration of the principle of rate gradualism. Thus, while I do not disagree that an alternative scaleback proposal such as that advanced by I&E Witness Sakaya in this proceeding could theoretically be reasonable, I concluded (in my rebuttal testimony) that Witness Sakaya's proposal was not consistent with the cost and rate gradualism principles.

Thus, unless the procedural problems that I identified can be resolved, I recommend that the Commission adopt a proportional scaleback approach to whatever revenue allocation proposal it adopts in this proceeding.

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

Q. In your direct testimony, you raised questions regarding the basis for retaining separate heating and non-heating rates for both the GM and GL rate classes. Please address Witness Ogden's response to your questions.

A. Witness Ogden confirms my hypothesis that the heating classes have existed for many (more than 40) years, stretching back to the time of fully integrated rates for generation, transmission and distribution service. Witness Ogden also confirms that, for cost allocation purposes, the heating classes peak in winter months, and that distribution costs are assigned to those classes based on the winter peaks in the ACOSS. Witness Ogden then indicates that a separate heating class rate allows "rate design to be tailored to these customers' load profiles, but then indicates that the lack of a demand charge in the winter

[8] This conclusion is not quite correct if some classes are awarded rate decreases, but that issue does not obtain in the present matter.

for the heating classes is related to revenue stability rather than matching costs and rates. Witness Ogden also makes reference to a higher load factor for the heating classes, which may be true on a billing demand basis but is not true for the Company's NCP demands in its cost allocation study.

At the end of the day, however, Witness Ogden indicates that the Company is willing to undertake an "internal" review of the rate design for the current heating service classes "for potential review" in a future base rate case, addressing ". . . 1) winter demand charge for heating classes, 2) phase out and merge the heating classes into non-heating classes, 3) closing the heating classes to new customers." The Company also sensibly proposes to consider bill impacts resulting from any proposed change in rate design.

I agree with the Company's proposal, with only minor modifications. I agree that a detailed evaluation of the general service rate design cannot reasonably take place in the context of this proceeding, and it is best carried out by the Company between rate filings. The minor modifications/clarifications I propose are as follows: First, I recommend that this review be submitted with the Company's next base rates case filing for public review. Witness Ogden's references to "internal review" and "potential review" are a recipe for continuing the status quo. Second, while bill impacts are an important consideration, they should be considered as part of a rate design transition, and not as rationale for rejecting cost-based rate design changes.

Q. In your direct testimony, you also raised a question about the mix of revenues recovered in the demand and energy charges in the Rate GM tariff (both above and below 25 kW). Please address Witness Ogden's response.

A. Witness Ogden indicates that the Company carefully considered the balance between demand charge and energy charge revenues, and it opted to disproportionately increase the energy charge to improve revenue stability and to protect low load factor customers from high bills. Because it is not feasible to precisely match rate design with the cost causation parameters in the ACOSS, the Company's approach is not obviously unreasonable. In moving to greater dependence on the energy charge rather than the demand charge, however, the Company is generally moving away from cost-based rates. My experience also is that Pennsylvania EDCs have generally been increasing the relative importance of demand charges (vis-à-vis energy charges) rather than decreasing them. Given its preference for energy charges, the Company may wish to consider modifying its energy charges to better align with distribution system peak periods, through seasonal or other time-differentiated rates.

However, because the Company has agreed to undertake a review of the heating class tariff design for its next base proceeding, I do not recommend that it also undertake a detailed review of the energy/demand split in the GM tariff at this time. The compounding effect on rates of two significant tariff changes can often be problematic.

5. Small Business Initiatives

Q. Does the Company acknowledge that it has not recognized revenues from incremental loads related to the Community Development Rider ("CDR") program in its test year forecast and that the benefits would flow to shareholders in the near term?

A. Yes, in Witness Everett's rebuttal testimony at page 8.

Q. Does the Company acknowledge that there may be free riders associated with the proposed CDR program?

A. Yes, in Witness Everett's rebuttal testimony at page 8-9.

Q. Do you agree with Witness Everett's contention regarding the CDR program that " . . . even if the Company were to benefit from these increases in sales in the short run, customers are not harmed and all the benefits from increased sales contributing to fixed costs in the long run accrue to all customers, not the Company"?

A. Only in part. Witness Everett is incorrect about the lack of harm, since the Company is including the costs of the program in the FPFTY revenue requirement, rather than funding the initiative through shareholder funds. I agree that any longer-term benefits of incremental loads (excluding all free-riding loads) will eventually accrue to ratepayers. Thus, the equity balance of the CDR program is as follows. The Company incurs no cost and no risk, and it benefits in the short run from any incremental load. Ratepayers bear the entire upfront cost, and they may or may not see longer term benefits from the incremental loads associated with the program. I do not believe that this qualifies as an equitable balance of risks, costs and rewards between shareholder and ratepayer. I therefore retain the recommendations in my direct testimony.

Q. Turning to the New Business Stimulus Rider ("NBSR"), Company Witness Kubiak frames the policy issue as follows: "The question remains, in the face of an unprecedented economic impact from a global pandemic, is the utility's role in its community to simply continue providing safe, reliable service as he asserts, or is it reasonable to consider that additional assistance may be needed?" Do you agree?

A. Generally, I do. I observe only that by "utility's role," Witness Kubiak refers to the utility as the entity that imposes a fee (or tax) on captive ratepayers in order to achieve a general social benefit, as well as a rate reduction benefit for certain favored ratepayers. Witness Kubiak makes it clear that the utility is not the entity that will fund such benefits – it is the ratepayers.

6. <u>Electric Vehicle Charging Subsidies</u>

Q. Witness Deal representing ChargePoint responds to your direct testimony by expressing disappointment that you recommend rejecting programs that ". . . would provide significant benefits to many small businesses who may be interested in hosting EV charging stations or electrifying their fleets." Please respond.

A. In representing the OSBA, I attempt to take a principled approach to intra-class revenue recovery and rate design issues. I am primarily motivated by attempting to match revenues with costs, a principle which the Commonwealth Court has denoted the "polestar" criterion for ratemaking.

Witness Deal is correct that subsidies for EV charging infrastructure may possibly help some small businesses, while also helping equipment vendors such as ChargePoint. What Witness Deal ignores is that these subsidies are necessarily provided by other small business customers. I therefore worked with OSBA to offer a set of reasonable regulatory principles that we believe the Commission should consider in evaluating whether EV charging infrastructure should be subsidized, and thus how to reasonably balance the interests of both the beneficiaries and providers of the subsidies. These principles are set forth in my direct testimony at pages 32-34. While the specifics vary, these principles are generally applicable to other proposed subsidy programs for small business customers.

In addition to the regulatory principles listed in my direct testimony, it is also important to recognize that adopting subsidies for EV charging infrastructure at this time will require a tax on small businesses, many of whom have been devastated by the pandemic. The damage from the pandemic to small businesses is well-documented.[9] In contrast, at least some of the benefits of the subsidies will flow to equipment vendors such as ChargePoint, whose business has boomed over the past year. ChargePoint has a market cap of some $7.5 billion at 5 August 2021.[10] ChargePoint reports that its quarter-ending April 2021 revenues are up 24 percent over the prior year, with gross margin up 21 percent. ChargePoint expects its current-year second quarter revenues to increase by 13.5 to 25.9 percent relative to its first quarter revenues. ChargePoint also reports that EV sales are up 40 percent year over year.[11] Very few small businesses can sport such numbers.

Thus, the Commission should consider whether it is equitable to require day care centers, restaurants, hair salons, dry cleaners, retail shops and the wide array of other small businesses, many who are struggling to survive, to subsidize these booming businesses.

Q. Witness Deal also argues that you ignored the benefit associated with future EV charging loads to other base rate customers. Please respond.

A. I acknowledged the potential for such benefits. However, there is no evidence that subsidies to EV charging infrastructure will increase distribution system loads to the benefit of other customers. First, there is no evidence that such subsidies result in increased load, because EV charging load will grow with or without subsidies. How much of the incremental EV charging load would not have occurred without the subsidies is unanalyzed and unknown. Second, it is far from clear, even if there are incremental loads

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[9] See, e.g., OCA Statement No. 5 at 9-14. Moreover, even as of the most recent US Census survey (July 18, 2021), over 67 percent of Pennsylvania businesses still report that the pandemic is having either a large or moderate negative impact on them. See https://portal.census.gov/pulse/data/

[10] https://finance.yahoo.com/quote/CHPT?p=CHPT&.tsrc=fin-srch reviewed 5-Aug-2021 8:10a.

[11] https://s22.q4cdn.com/779683160/files/doc_financials/2022/q1/ChargePoint-Reports-First-Quarter-Fiscal-2022-Financial-Results-2021.pdf reviewed 5-August-2021 8:13a.

associated with subsidized charging infrastructure, whether those loads will generate revenues in excess of the incremental cost to serve. Depending on the nature of the charging operations, the loads can potentially have extremely unattractive load factors, and may put strains on specific components of the electric distribution system requiring system upgrades. At this time, the long-term impact of increased EV charging loads on distribution system costs is speculative. For those reasons, I do not believe that hypothetical benefits from possible incremental loads justifies significant utility investment at ratepayer expense.

Q. Turning to the Company's rebuttal Witness Olexsak, does the Company acknowledge that its proposed subsidy programs for EV charging infrastructure would address only a small part of the demand as you indicated in your direct testimony.

A. Yes. Witness Olexsak acknowledges this fact at page 17 of the rebuttal testimony. From a ratepayer perspective, the good news is that this approach limits the magnitude of the subsidies demanded from them. From a regulatory perspective, the bad news is that this approach represents a textbook example of undue discrimination, with similarly situated customers being treated unequally. Recipients of the subsidies must either be fast, lucky, politically connected or have advantageous relationships with the Company to get the subsidies, while other less fortunate customers do not.

Q. Witness Olexsak indicates that you do not dispute the Company's assertion that the Fleet Charging Pilot programs have a positive cost-benefit ratio. Please respond.

A. As I indicated at page 33 in my direct testimony, any cost benefit analysis of subsidies for EV charging infrastructure must separate incremental loads that would not otherwise be achieved and free-rider loads that the Company would otherwise have seen without the subsidies. It is my understanding that the Company did not make such an assessment for its Fleet Charging Pilot and assumed that all loads associated with subsidized infrastructure were causally related to the subsidies.

Q. Does the Company acknowledge that small business customers will be required to contribute to subsidies for the Fleet Charging Pilot program?

A. Yes. At page 48, Witness Olexsak indicates, "The remaining program costs are socialized among the C&I customer class."

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-S1

RDK ELECTRONIC WORKPAPERS

RDK WP1-S: Near Replication of DLC Rebuttal ACOSS

RDK WP2-S: RDK Surrebuttal ACOSS

Workpapers will be transmitted via separate e-mail attachment simultaneous to e-mail service of this document

EXHIBIT IEc-S2

REERENCED INTERROGATORY RESPONSES
(Statements OSBA-I-R and OSBA-I-S)

DLC-NEP-I-1
DLC-NEP-I-2
DLC-NEP-I-6
DLC-NEP-I-15
DLC-NEP-I-25
Nationwide-I-15
Nationwide-I-16
OSBA-I-1
OSBA-I-3
OSBA-I-8
OSBA-1-11
OSBA-I-12
OSBA-I-27
OSBA-I-33
OSBA-I-35
OSBA-I-36

Docket Nos.: R-2021-3024750; C-2021-3025538
C-2021-3025462; C-2021-3026057
Sponsor: Teresa Ringenbach
Title: V.P. Business Development

Nationwide Energy Partners, LLC
Response to Duquesne Light Company Interrogatories and Requests for Production of Documents, Set I, No. 1

1. Please identify the number of master metered buildings in Pennsylvania that are submetered by, or for which the electric service is otherwise managed by, NEP.

RESPONSE:

Five (5).

Docket Nos.: R-2021-3024750; C-2021-3025538
C-2021-3025462; C-2021-3026057
Sponsor: Teresa Ringenbach
Title: VP Business Development

Nationwide Energy Partners, LLC
Response to Duquesne Light Company Interrogatories and Requests for Production of Documents, Set I, No. 2

2. For the buildings identified in response to question (1): please identify the number of tenants, by year and broken down by residential and nonresidential, to which electric service was terminated for the period 2017 through 2021 YTD.

RESPONSE:

The number of total disconnections executed by NEP in Pennsylvania for each year are below. These figures do not account for multiple disconnections of the same tenant. Therefore, because some tenants are disconnected multiple times, the number of individual tenants who were disconnected at any point during the given year will be lower than the numbers reflected below.

2017:	0 residential tenants; 0 nonresidential tenants
2018:	4 residential tenants; 0 nonresidential tenants
2019:	113 residential tenants; 0 nonresidential tenants
2020:	27 residential tenants; 0 nonresidential tenants
2021 YTD:	63 residential tenants; 0 nonresidential tenants

Docket Nos.: R-2021-3024750; C-2021-3025538
C-2021-3025462; C-2021-3026057
Sponsor: Drew Romig
Title: Corporate Counsel

Nationwide Energy Partners, LLC
Response to Duquesne Light Company Interrogatories and Requests for Production of Documents, Set I, No. 6

6. With respect to NEP-submetered residential buildings in Pennsylvania, provide NEP's policies, procedures, and practices for each of the following, and provide all related documents.

   a. The rates charged to residential tenants for electric service.
   b. How residential tenants' rates for electric service are established.
   c. Whether and how residential tenants can participate in the calculation of rates for electric service.
   d. The information available to residential tenants regarding how their electric rates are calculated, and the method by which residential tenants access such information.
   e. The structure and billing determinants reflected residential tenants' electric rates (e.g., fixed customer charge, per-kWh charges, etc.).
   f. How residential tenants are billed for electric service (e.g., separate monthly bill, etc.)
   g. Residential tenants' options for remitting payment for electric service
   h. Payment terms applicable to residential tenants' charges for electric service. Address in your answer, at a minimum: the time period between bill render date and due date, and the amount and applicability of late payment charges.
   i. How residential tenants' obligations to pay for electric service are enforced.
   j. How residential tenants choose an electric generation supplier (EGS).
   k. Payment arrangement terms to which residential tenants are entitled.
   l. Due process prior to service termination to which residential tenants are entitled.
   m. The process by which residential tenant disputes regarding electric service (including but limited to disputes concerning billing, metering, service termination, and quality of service) are initiated, received, evaluated, resolved, and/or appealed (as applicable).
   n. How residential tenants are made aware of the dispute processes identified in response to part (m) above.
   o. Bill-payment assistance programs available to residential tenants.
   p. How residential tenants are made aware of the bill-payment assistance programs identified in response to part (o) above.
   q. Energy efficiency programs available to residential tenants.
   r. How residential tenants are made aware of the energy efficiency programs identified in response to part (q) above.
   s. Budget billing programs available to residential tenants.

t. How residential tenants are made aware of the budget billing programs identified in response to part (s) above.
u. Time-of-use programs made available to residential tenants.
v. For each of the items identified in responses to (a) through (u) above, please identify the entity(ies) with the discretion to establish and/or modify such item, and describe and explain the process by which such entity(ies) establish and/or modify such item.

RESPONSE:

Response 6.a.: The rates charged to residential tenants by NEP are the approved rates of the local electric utility. NEP employs a team of qualified individuals to monitor the approved rates of the local electric utilities in each service territory in which it operates, including all riders and fees, and to incorporate those rates into NEP's billing system on a monthly basis. In order to ensure that amounts billed by NEP do not exceed those that would be billed by the local utility in compliance with 66 Pa.C.S. Section 1313, Price upon resale of public utility services, each component of the utility's rates are rounded down to the nearest cent prior to being summed for a total billing amount.

Response 6.b.: See Response 6.a.

Response 6.c.: Residential tenants can only participate in the calculation of rates for electric service to the extent that those rates are established through PUC proceedings. NEP does not alter the established rates, and therefore there is no process at NEP in which resident participation is possible.

Response 6.d.: NEP communicates to residents, including on their monthly billing statements, that the rates applied to their usage are the "applicable local utility rates for residential service." Utility tariff rates and riders are publically available to utility customers as well as members of the public.

Response 6.e.: See Response 6.a.

Response 6.f.: Residential tenants receive separate paper monthly bills, and may elect to receive paperless billing and/or manage their account through NEP's online resident portal or smartphone app.

Response 6.g.: Residents may pay their bills by check, in person at Walmart and Kroger locations, by signing up for Autopay with a credit card, debit card or bank account, via electronic bill pay set up with their bank, online through NEP's resident portal or smartphone app, or by phone.

Response 6.h.: Bills are due a minimum of 14 days from the date the bill is issued. NEP allows a 7-day grace period following the due date during which no action is taken, and payments received during the grace period are considered on-time. A twenty dollar ($20) late payment fee is applied to accounts with past-due balances greater than $100 for payments received following the grace period.

Response 6.i.: Tenants obligations to pay for electric service are enforced as directed by the property owner or condominium association and described in the contract between that entity and NEP, and may include disconnection of electric service and/or eviction of apartment tenants at the landlord's option.

Where disconnection of service has been authorized by the property owner or condominium association, NEP adheres as closely as possible to the procedures applicable to public utilities in Pennsylvania, including all notice requirements, the Winter Disconnect Rule, and COVID-19-related restrictions, prior to disconnecting electric service (See Response 6.l. below). Where specified by an agreement between an apartment community owner and NEP, NEP may request that the community owner initiate eviction proceedings against tenants whose past-due balances exceed $500. Under all such agreements, community owners have the option of assuming the tenant's past-due balance instead of initiating eviction proceedings.

Response 6.j.: Residential tenants do not independently choose an EGS apart from the property owner's selection of a competitive supplier.

Response 6.k.: If a resident is scheduled for disconnection and is unable to pay the full past due balance by the date on the disconnect notice, NEP will offer a 50/50 payment plan to avoid disconnection. The plan will require a payment of 50% of the amount on the disconnect notice (by the date on the notice) and the remaining 50% within 14 days of the disconnect day. This plan is only applicable prior to disconnection.

40% Down Plan: This payment plan requires a down payment of 40% of the total current balance unless a community requests NEP to offer 30%. Once the payment is posted to the account, we will be able to set the remaining balance on the account for a 3, 6, or 9-month plan. In order to enroll in the 9-month plan we would need to receive a copy of the resident's current lease. Once the payment is posted we will disperse evenly at a 1% interest rate. The payment plan amount is a separate and additional charge added to the monthly charges. If the bill is not paid in full the payment plan will be canceled and the resident will have to pay a 50% down payment to set up another payment plan.

Response 6.l.: NEP adheres as closely as possible to the procedures applicable to public utilities in Pennsylvania, including all notice requirements, the Winter Disconnect Rule, and COVID-19-related restrictions, prior to disconnecting electric service. Written notice of disconnect is postmarked to residents at least 14 days prior to disconnection in Summer months (4/16 - 10/31) and at least 24 days prior to disconnection in Winter months (11/1 - 4/15). NEP will not disconnect power if the projected low for the day of disconnect is below 10 degrees. NEP will not disconnect power if the projected high for the day of disconnect and the day after disconnect is below 32 degrees.

Response 6.m.: Resident complaints and questions are fielded by NEP's in-house call center and resident support specialists. Any issues that cannot be resolved by the first-line resident support team are escalated to the appropriate department for further evaluation and response, including but not limited to meter testing and rate verification.

Response 6.n.: Residents options for contacting NEP's resident support team are indicated on resident bills, within NEP's online resident portal and smartphone app, and on NEP's website.

Response 6.o.: Residents in need of bill payment assistance are directed to local community organizations. Depending on their income level, need and their NEP bill, residents may or may not qualify for assistance.

Response 6.p.: NEP does not typically service low income properties. To the extent tenants need assistance in payment they are directed to online resources or provided bill pay options as indicated in Response 6.k.

Response 6.q.: NEP does not provide energy efficiency programs on an individual by individual resident basis. NEP assists property owners with energy efficiency upgrades on a property-wide basis.

Response 6.r.: See Response 6.q. Residents have access to any technologies which may impact usage within their unit and have access to individual usage through smart meter data.

Response 6.s.: NEP does not presently offer budget billing programs.

Response 6.t.: See Response 6.s.

Response 6.u.: NEP does not presently offer time-of-use programs.

Response 6.v.: Items "a" through "e" cover local electric utility rates which are established through the ratemaking process at the Pennsylvania Public Utility Commission. As noted in Item "c," NEP does not alter the approved rates of the local electric utility, and is bound by 66 Pa.C.S. Section 1313 to bill tenants at rates that do not exceed those of the local electric utility. Items "f" and "i" are governed by NEP's contract with the property owner, and cannot be altered except by mutual agreement in writing of the property owner and NEP. Items "h," "k" through "n," and "p" through "u" are determined internally by NEP with reference to industry best practices, the practices of local electric utilities, and the technological capabilities available to NEP.

Docket Nos.: R-2021-3024750; C-2021-3025538
C-2021-3025462; C-2021-3026057
Sponsor: Teresa Ringenbach
Title: VP Business Development

Nationwide Energy Partners, LLC
Response to Duquesne Light Company Interrogatories and Requests for Production of Documents, Set I, No. 15

15. Reference Direct Testimony of Teresa Ringenbach, p. 7, lines 4-7. Provide all documents related to the impacts of NEP's services on utilities or non-participating customers.

RESPONSE:

NEP has operated in the PECO and Ohio utility service territories. The majority of our business is within the AEP Ohio service territory. None of the rate cases in PECO or AEP Ohio have included submetering by NEP as a revenue impact.

AEP Ohio rate cases since NEP business began:

Case Number	Case Title	Open Date	Closed Date
20-0585-EL-AIR	Ohio Power Company	04/09/2020	
11-0352-EL-AIR	OHIO POWER COMPANY	01/27/2011	
R-2018-3000164	PECO Energy Company – Electric Division	03/29/2018	12/20/2018
R-2021-3024601	PECO Energy Company – Electric Division	03/30/2021	

Docket Nos.: R-2021-3024750; C-2021-3025538
C-2021-3025462; C-2021-3026057
Sponsor: Teresa Ringenbach
Title: VP Business Development

Nationwide Energy Partners, LLC
Response to Duquesne Light Company Interrogatories and Requests for Production of Documents, Set I, No. 25

25. Reference Direct Testimony of Teresa Ringenbach, p. 18, lines 9-10. Does Ms. Ringenbach agree that access to Duquesne Light's Customer Assistance Program may also allow tenants to reduce their costs? If not, why not?

RESPONSE:

It is Ms. Ringenbach's understanding that Duquesne Light's proposal is that a master metered building will not have submeters for tenants and tenants will also no longer have access to the Customer Assistance Program. Under this circumstance, no, the tenant will not be able to access the Customer Assistance Program to reduce their costs.

In addition, not all tenants qualify for the Customer Assistance Program. Therefore access to the Program may be available, but actual use of the program is not. NEP will provide an immediate minimum discount to al tenants regardless of income.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of
Nationwide Energy Partners, LLC

Set I

Witness: C. James Davis

Nationwide-I-15

15. Reference Duquesne Statement No. 6 p. 6 lines 4-9: Please provide any Documents or studies Duquesne has performed, obtained, consulted or utilized in the last five (5) years addressing inter- and intra-class revenue allocation impacts from converting existing services from individually metered dwelling units to master metered buildings.

Response:

The Company has not performed any studies, nor does it have any documents addressing inter- and intra-class revenue allocation impacts from converting existing services from individually metered dwelling units to master metered buildings.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of
Nationwide Energy Partners, LLC

Set I

Witness: C. James Davis

Nationwide-I-16

16. Please provide any Documents or studies Duquesne has performed, obtained, consulted or utilized in the last five (5) years addressing inter- and intra-class revenue allocation impacts from prospectively allowing master meters on buildings that house multi-family tenants who would otherwise be individually metered under Duquesne's current Tariff Rules.

Response:

The Company has not performed any studies, nor does it have any documents addressing inter- and intra-class revenue allocation impacts from prospectively allowing master meters on buildings that house multi-family tenants who would otherwise be individually metered under Duquesne's current Tariff Rules. Such an evaluation would be needed before any change in master metering rules on a broad scale could be adopted. See also DLC St. No. 6, p. 6, lines 4-9.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: David Ogden

OSBA-I-1

1. To the extent available, please provide a dataset showing number of customers and recent annual kWh consumption for the GS, GM, GMH, GL, GLH and L rate classes (separately) by NAICS or SIC Code, in MS Excel electronic format. Please segregate the GM and GMH classes into the below and at/above 25 kW categories.

Response:

Please see OSBA-I-1 - Attachment 1 for the dataset showing the number of customers at December 31, 2020 and the 2020 annual kWh consumption for GS, GM, GMH, GL, GLH, and L rate classes. Governmental, institutional and nonprofit entities are likely represented in every rate schedule. The Company does not track customers within each C&I rate schedule by NAICS code. At the time a customer account is established, the Company will assign the customer to the appropriate commercial or industrial rate schedule based on the customer's description of their business.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: Katherine Scholl

OSBA-I-3

3. Please provide a copy of a recent representative bill for the GS, GM (both under and over 25 kW), GMH (both under and over 25 kW), GL, GLH and L rate classes. For the GMH classes, please provide a winter bill and a summer bill.

Response:

See attachments:
OSBA-I-3 - Attachment 1 GL.pdf
OSBA-I-3 – Attachment 2 GLH.pdf
OSBA-I-3 - Attachment 3 GMG25.pdf
OSBA-I-3 - Attachment 4 GMHG25 summer.pdf
OSBA-I-3 - Attachment 5 GMHG25 winter.pdf
OSBA-I-3 - Attachment 6 GMHL25 summer.pdf
OSBA-I-3 - Attachment 7 GMHL25 winter.pdf
OSBA-I-3 - Attachment 8 GML25.pdf
OSBA-I-3 - Attachment 9 GS.pdf
OSBA-I-3 - Attachment 10 L.pdf

REDACTED

DUQUESNE LIGHT CO.

[redacted]

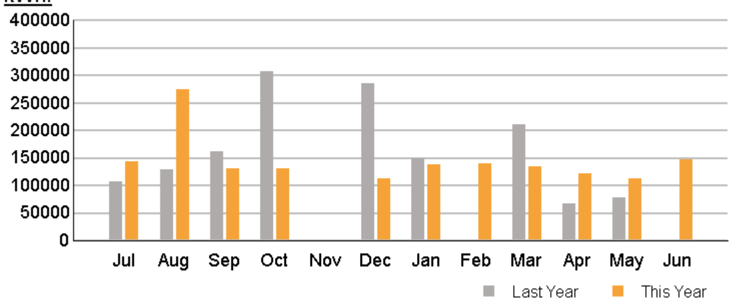
Account # [redacted]

Due Date	Amount Due
07/22/2021	$12,675.31

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	150585	5020	30	71
Last Month	115935	3998	29	55
Same Month Last Year	0	0	0	0

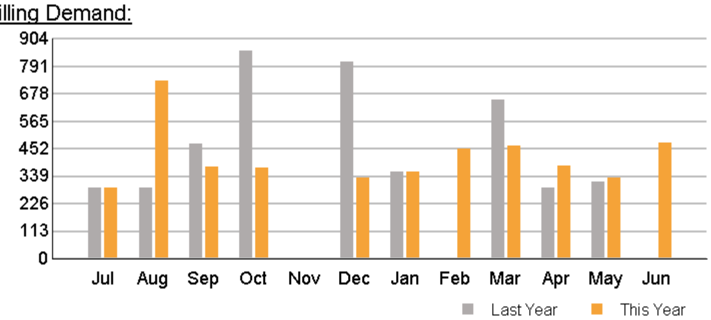
kWh:



Average Monthly Usage for the last 12 months: 135952 kWh

Total Annual Usage for the last 12 months: 1631426 kWh

Billing Demand:



Bill Summary

Bill ID: [redacted] **Date Prepared: 06/21/2021**

Previous Account Balance	$20,441.55
Payment(s) Received as of 06/21/2021	-$20,441.55
Balance Forward	**$0.00**
DLC Charges	$5,161.12
Supply Charges - [redacted]	$7,514.19
AMOUNT DUE BY 07/22/2021	**$12,675.31**

Message Center

Signing up for our e-Bill program is fast and easy! Enroll today at **DuquesneLight.com/ebill.**

Duquesne Light shares customer information with some trusted partners that offer programs and services you may find valuable. These trusted service providers operate under confidentiality agreements and cannot share your information with others. For more information, please visit **DuquesneLight.com/privacy**.

MAR: Barbara Leja - 412-393-2428

Online: www.DuquesneLight.com

Phone: 412-393-7300

BI_POSTAL_20210621PRD.xml

Billing and meter reading details on page 3

DUQUESNE LIGHT CO.

Please return this portion with your payment. Please enclose check facing forward. Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-07-22

Due Date	Amount Due
07/22/2021	$12,675.31

$ DO NOT PAY

USD Amount Enclosed

Account #

[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

DO NOT PAY, YOUR AUTOPAY PAYMENT OF $12,675.31 WILL BE PROCESSED ON 07/22/2021

REDACTED

[redacted] Account # [redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

Sign up online for any of the following services:

- **E-Billing** - Free service lets you view bills online
- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

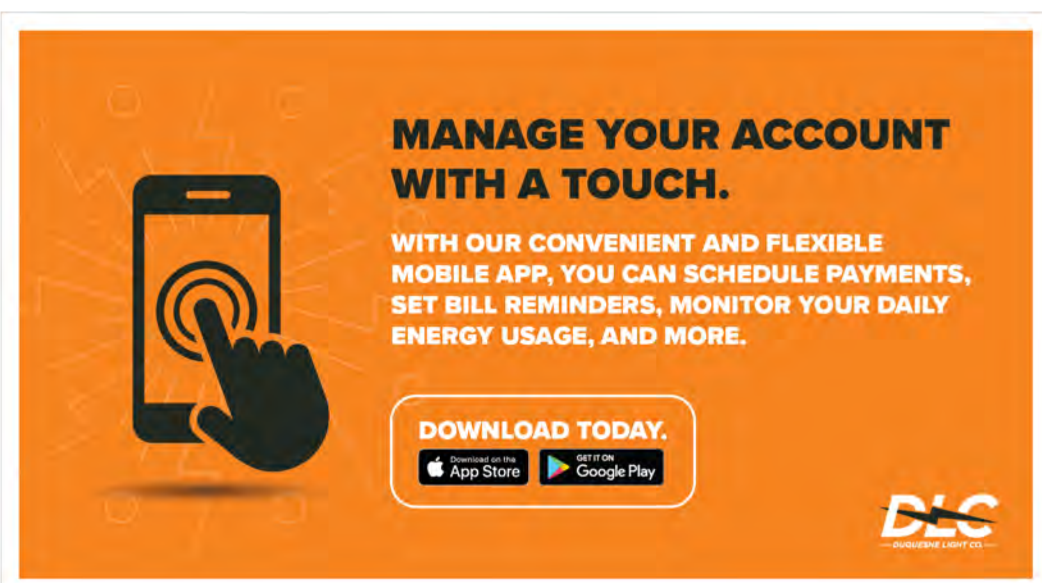
Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

- **Customer Charge** – A monthly basic service charge that includes costs for meter reading, customer billing, service equipment, and other expenses. These expenses are incurred even in months when customers do not use electricity.
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
- **Meter Reading** – An actual (Act) reading is a reading taken from the meter. An estimated (Est) reading is used when no actual reading is available and is based on past electric usage.
- **Non-Basic Service Charges** – Any category of service not related to basic service.
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

BI_POSTAL_20210621PRD.xml

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		277/480V
Meter Readings - kWh		
Present	06/17/2021 Act	7,485.2980
Prior	05/18/2021 Act	7,234.3230
Difference		250.9750
Your Meter Multiplier		600
Total kWh Used		150,585.0000
Meter Readings - kVARh		
Present	06/17/2021 Act	1,088.0090
Prior	05/18/2021 Act	1,017.5650
Difference		70.4440
Your Meter Multiplier		600
kVARh		42,266.4000
Demand Information		
Demand Reading (on-peak)		0.8070
kW (on-peak)		484.2000
PFM		1.0000
Adjusted kW		484.2000
Total Billed Demand		**484.2000**
Total kWh Used		**150,585.0000**

Current Bill Details

DLC Rate	GL-Large Commercial		
DLC Charges			**$5,161.12**
Customer Charge		$0.01	
Demand Distribution	300.0000 kW@ $10.600000	$3,180.00	
Demand Distribution	184.2000 kW@ $8.410000	$1,549.12	
PA EEA Fixed		$93.62	
PA EEA Fixed		$94.23	
PA EEA Variable	103.3536 kW@ $0.270000	$27.91	
PA EEA Variable	135.1547 kW@ $0.130000	$17.57	
Smart Meter Charge Thre	MTR@ $0.070000	$0.07	
DSIC Surcharge	4.01%	$199.00	
Pennsylvania Tax Adjustment		-$0.41	
Supply Charges - [redacted]			**$7,514.19**
Generation-Trans	150585.0000 kWh@ $0.049900	$7,514.19	
Service Charges			**$12,675.31**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]

Rate Schedule: GL-Large Commercial

The Price to Compare for your rate class is not calculated because supply rates change hourly, with charges based on your load in those hours. See Rider No. 9, Day-Ahead Hourly Price Service, in our tariff, which can be found at www.duquesnelight.com. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

- Generation/Supply prices and charges are set by the electric generation supplier you have chosen
- The Public Utility Commission regulates distribution prices and services
- The Federal Energy Regulatory Commission regulates transmission prices and services

[redacted] [redacted]

For questions regarding the supplier portion of your bill, call [redacted]

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.
- Duquesne Light offers energy efficiency programs to help customers save money by conserving energy and reducing demand. To participate or to learn more about these programs, visit www.wattchoices.com.

Additional Notifications

- Effective Jun. 1, changes in the costs to enhance the competitive energy market in PA, will increase the monthly bill of a large commercial customer using 500 kW and 200,000 kWh by about $0.02 or less than 1%.
- Effective Jun. 1, changes in the Energy Efficiency Surcharge, reflecting costs related to the Watt Choices program, will decrease the monthly bill of a large commercial customer using 500 kW and 200,000 kWh by about $121 or less than 1%.
- The Price to Compare for your rate class is not calculated because supply rates change hourly, with charges based on your load in those hours. See Rider No. 9, Day-Ahead Hourly Price Service, in our tariff, which can be found at www.duquesnelight.com.
- Estimated Gross Receipts Tax of $747.85 and Estimated PA State Tax of $861.92 are included in your rates.

OSBA-I-3 - Attachment 2 GLH

REDACTED

DUQUESNE LIGHT CO.

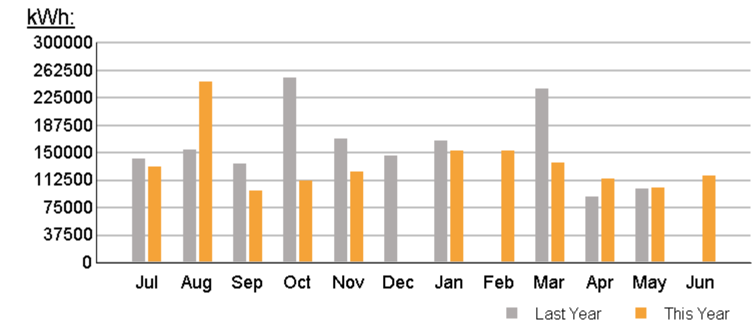
[redacted]

Account # [redacted]

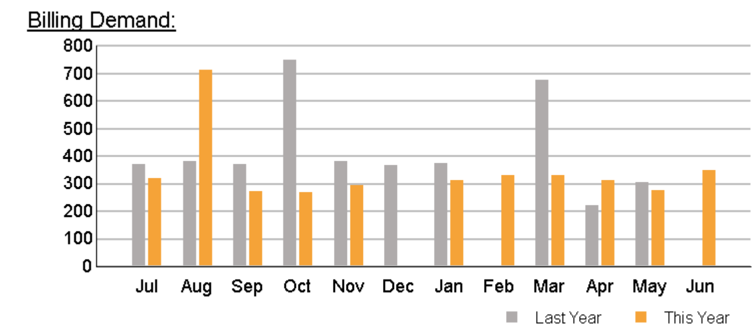
Due Date	Amount Due
07/07/2021	$4,348.48

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	121654	4055	30	71
Last Month	104704	3610	29	55
Same Month Last Year	0	0	0	0



Average Monthly Usage for the last 12 months: 126657 kWh
Total Annual Usage for the last 12 months: 1519886 kWh



Bill Summary

Bill ID: [redacted] **Date Prepared: 06/21/2021**

Previous Account Balance	$3,117.93
Payment(s) Received as of 06/01/2021	-$3,117.93
Balance Forward	**$0.00**
DLC Charges	$4,348.48
AMOUNT DUE BY 07/07/2021	**$4,348.48**

Message Center

Signing up for our e-Bill program is fast and easy! Enroll today at **DuquesneLight.com/ebill.**

Duquesne Light shares customer information with some trusted partners that offer programs and services you may find valuable. These trusted service providers operate under confidentiality agreements and cannot share your information with others. For more information, please visit **DuquesneLight.com/privacy**.

MAR: Christina Navadauskas - 412-393-7851
Online: www.DuquesneLight.com

BI_POSTAL_20210621PRD.xml

Phone: 412-393-7300

Billing and meter reading details on page 3

Please return this portion with your payment. Please enclose check facing forward.
Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-07-07

DUQUESNE LIGHT CO.

Due Date	Amount Due
07/07/2021	$4,348.48

$ ________

USD Amount Enclosed

Account #
[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

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- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

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Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

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- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
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- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
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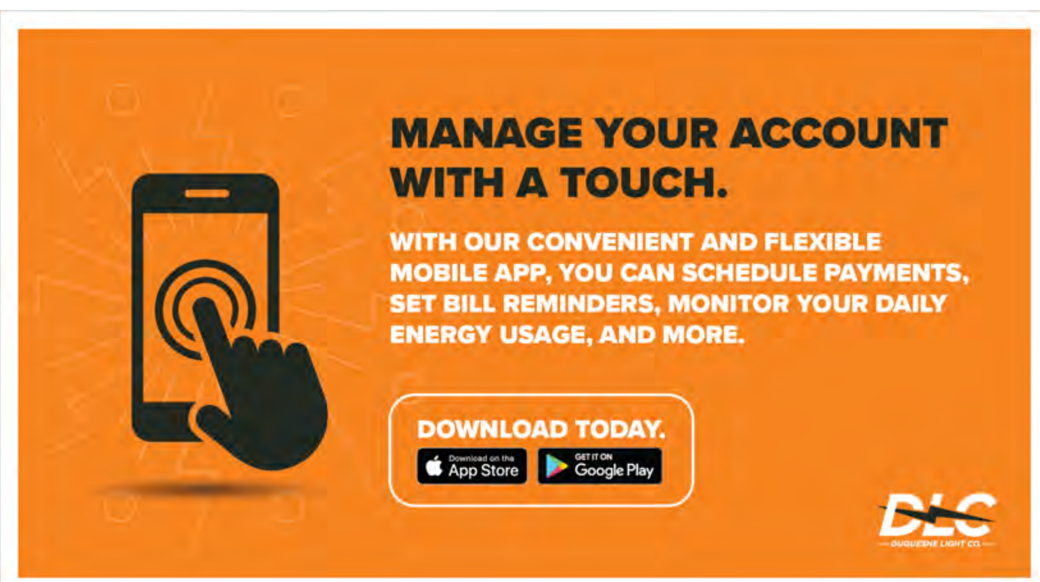
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

REDACTED

[redacted] **Account #** [redacted]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		277/480V
Meter Readings - kWh		
Present	06/17/2021 Act	13,153.9780
Prior	05/18/2021 Act	12,849.8420
Difference		304.1360
Your Meter Multiplier		400
Total kWh Used		121,654.4000
Meter Readings - kVARh		
Present	06/17/2021 Act	1,841.9440
Prior	05/18/2021 Act	1,716.1680
Difference		125.7760
Your Meter Multiplier		400
kVARh		50,310.4000
Demand Information		
Demand Reading (on-peak)		0.8510
kW (on-peak)		340.4000
PFM		1.0481
Adjusted kW		356.7732
Total Billed Demand		**356.7732**

Current Bill Details

DLC Rate	GLH-Large Commercial Heating		
DLC Charges			**$4,348.48**
Demand Distribution	300.0000 kW@ $10.600000	$3,180.00	
Demand Distribution	56.7732 kW@ $8.410000	$477.46	
Customer Charge		$0.01	
PA EEA Fixed		$93.62	
PA EEA Fixed		$94.23	
PA EEA Variable	141.4546 kW@ $0.270000	$38.19	
PA EEA Variable	184.9791 kW@ $0.130000	$24.05	
Smart Meter Charge Thre	MTR@ $0.070000	$0.07	
DSIC Surcharge	4.01%	$156.70	
Pennsylvania Tax Adjustment		-$0.33	
Sales Tax		$284.48	

Total kWh Used 121,654.4000

Service Charges $4,348.48

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GLH-Large Commercial Heating

The Price to Compare for your rate class is not calculated because supply rates change hourly, with charges based on your load in those hours. See Rider No. 9, Day-Ahead Hourly Price Service, in our tariff, which can be found at www.duquesnelight.com. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

- Generation/Supply prices and charges are set by the electric generation supplier you have chosen
- The Public Utility Commission regulates distribution prices and services
- The Federal Energy Regulatory Commission regulates transmission prices and services

[redacted]

For questions regarding the supplier portion of your bill, call [redacted]

- [redacted] will provide a separate bill for your generation and transmission.

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.

BI_POSTAL_20210621PRD.xml

Additional Notifications

- Duquesne Light offers energy efficiency programs to help customers save money by conserving energy and reducing demand. To participate or to learn more about these programs, visit www.wattchoices.com.
- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- Effective Jun. 1, changes in the costs to enhance the competitive energy market in PA, will increase the monthly bill of a large commercial customer using 500 kW and 200,000 kWh by about $0.02 or less than 1%.
- Effective Jun. 1, changes in the Energy Efficiency Surcharge, reflecting costs related to the Watt Choices program, will decrease the monthly bill of a large commercial customer using 500 kW and 200,000 kWh by about $121 or less than 1%.
- The Price to Compare for your rate class is not calculated because supply rates change hourly, with charges based on your load in those hours. See Rider No. 9, Day-Ahead Hourly Price Service, in our tariff, which can be found at www.duquesnelight.com.
- Estimated Gross Receipts Tax of $239.78 and Estimated PA State Tax of $276.35 are included in your rates.

REDACTED

DUQUESNE LIGHT CO.

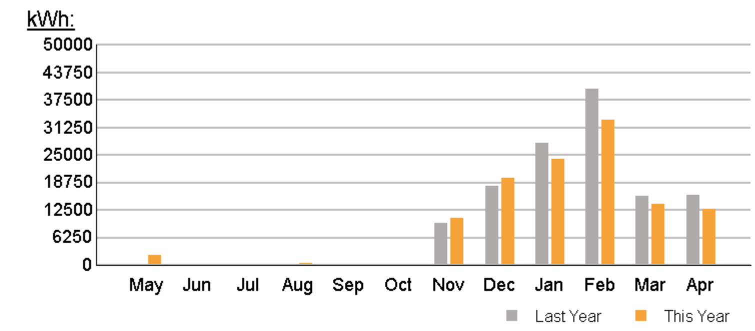
[redacted]

Account # [redacted]

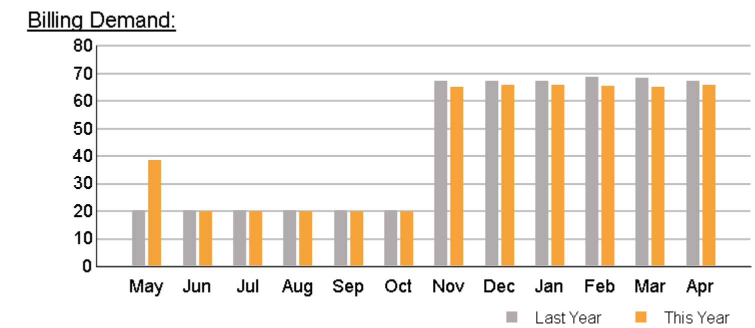
Due Date	Amount Due
05/10/2021	$681.66

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	13194	440	30	54
Last Month	14310	493	29	43
Same Month Last Year	16448	498	33	49



Average Monthly Usage for the last 12 months: 10271 kWh
Total Annual Usage for the last 12 months: 123246 kWh



Bill Summary

Bill ID: [redacted] **Date Prepared: 04/22/2021**

Previous Account Balance	$687.65
Payment(s) Received as of 03/30/2021	-$687.65
Balance Forward	**$0.00**
DLC Charges	$681.66
AMOUNT DUE BY 05/10/2021	**$681.66**

Message Center

Duquesne Light partners with Dollar Energy Fund to provide assistance to customers who struggle to pay their electric bill. If you would like to support the Dollar Energy Fund and your neighbors in need, make a tax deductible monthly pledge at **DuquesneLight.com/dollar**.

DOLLAR ENERGY FUND

BI_EBILL_20210422PRD.xml

Online: www.DuquesneLight.com **Phone:** 412-393-7300 *Billing and meter reading details on page 3*

DUQUESNE LIGHT CO.

Please return this portion with your payment. Please enclose check facing forward.
Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-05-10

Due Date	Amount Due
05/10/2021	$681.66

$ ___ , ___ . ___

USD Amount Enclosed

Account #
[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

REDACTED

[redacted] Account # [redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

Sign up online for any of the following services:

- **E-Billing** - Free service lets you view bills online
- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

- **Customer Charge** – A monthly basic service charge that includes costs for meter reading, customer billing, service equipment, and other expenses. These expenses are incurred even in months when customers do not use electricity.
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
- **Meter Reading** – An actual (Act) reading is a reading taken from the meter. An estimated (Est) reading is used when no actual reading is available and is based on past electric usage.
- **Non-Basic Service Charges** – Any category of service not related to basic service.
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.

Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DLC DUQUESNE LIGHT CO.

REDACTED

[redacted] **Account #** [redacted]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		277/480V
Meter Readings - kWh		
Present	04/22/2021 Act	10,315.5790
Prior	03/23/2021 Act	10,051.7050
Difference		263.8740
Your Meter Multiplier		50
Total kWh Used		13,193.7000
Meter Readings - kVARh		
Present	04/22/2021 Act	713.9600
Prior	03/23/2021 Act	695.7590
Difference		18.2010
Your Meter Multiplier		50
kVARh		910.0500
Demand Information		
Demand Reading (on-peak)		1.3290
kW (on-peak)		66.4500
PFM		1.0000
Adjusted kW		66.4500
Total Billed Demand		**66.4500**

Current Bill Details

DLC Rate	GM-Medium Commercial > 25		
Price to Compare	$0.0554 / kWh		
DLC Charges			**$681.66**
Customer Charge		$65.68	
PA EEA Surcharge	13193.7000 kWh@ $0.001300	$17.15	
Energy Distribution	13193.7000 kWh@ $0.009685	$127.78	
Demand Distribution	61.4500 kW@ $6.540000	$401.88	
Smart Meter Charge Thre	MTR@ $0.070000	$0.07	
DSIC Surcharge	4.01%	$24.56	
Pennsylvania Tax Adjustment		-$0.05	
Sales Tax		$44.59	

Total kWh Used	**13,193.7000**
Service Charges	**$681.66**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GM-Medium Commercial > 25

The current Price to Compare is listed above in Account Detail and will change quarterly beginning June 1. Your actual PTC may differ based on your specific demand & usage patterns. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

- Generation/Supply prices and charges are set by the electric generation supplier you have chosen
- The Public Utility Commission regulates distribution prices and services
- The Federal Energy Regulatory Commission regulates transmission prices and services

[redacted]

For questions regarding the supplier portion of your bill, call [redacted]

- [redacted] will provide a separate bill for your generation and transmission.

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.

Additional Notifications

- Duquesne Light offers energy efficiency programs to help customers save money by conserving energy and reducing demand. To participate or to learn more about these programs, visit www.wattchoices.com.
- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- A change in the Default Service Supply rate that went into effect March 1 decreased the overall bill of an average medium commercial customer (using 30 kW and 10,000 kWh) who purchases electric generation from Duquesne Light by about $76, or 8%.
- A change in the Distribution System Improvement Charge, effective April 1, will increase your monthly bill by about $2, or less than 1%.
- Estimated Gross Receipts Tax of $37.59 and Estimated PA State Tax of $43.32 are included in your rates.

DUQUESNE LIGHT CO.

Account # [redacted]

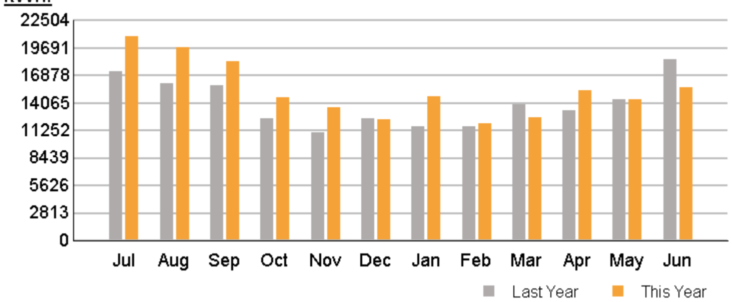
REDACTED

Due Date	Amount Due
07/09/2021	$1,801.75

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	15920	531	30	68
Last Month	14655	505	29	60
Same Month Last Year	18707	585	32	71

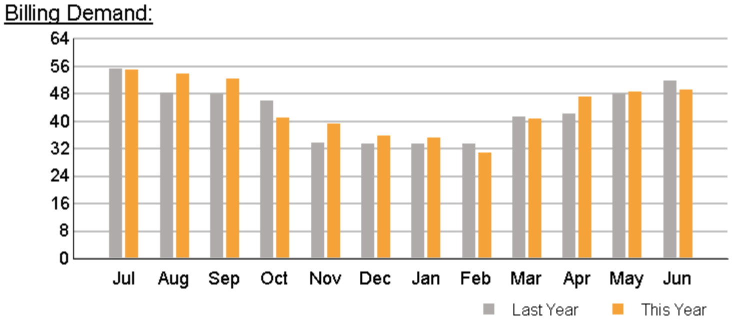
kWh:



Average Monthly Usage for the last 12 months: 15570 kWh

Total Annual Usage for the last 12 months: 186836 kWh

Billing Demand:



Bill Summary

Bill ID: [redacted] **Date Prepared: 06/23/2021**

Previous Account Balance	$1,274.19
Payment(s) Received as of 06/09/2021	-$1,274.19
Balance Forward	**$0.00**
DLC Charges	$659.03
Supply Charges	$1,142.72
AMOUNT DUE BY 07/09/2021	**$1,801.75**

Message Center

Signing up for our e-Bill program is fast and easy! Enroll today at **DuquesneLight.com/ebill.**

Duquesne Light shares customer information with some trusted partners that offer programs and services you may find valuable. These trusted service providers operate under confidentiality agreements and cannot share your information with others. For more information, please visit **DuquesneLight.com/privacy**.

BI_EDI_20210623PRD.xml

Online: www.DuquesneLight.com **Phone:** 412-393-7300

Billing and meter reading details on page 3

DUQUESNE LIGHT CO.

Please return this portion with your payment. Please enclose check facing forward. Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-07-09

Due Date	Amount Due
07/09/2021	$1,801.75

$ ______ , ______ . ______

USD Amount Enclosed

Account #

[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

Sign up online for any of the following services:

- **E-Billing** - Free service lets you view bills online
- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

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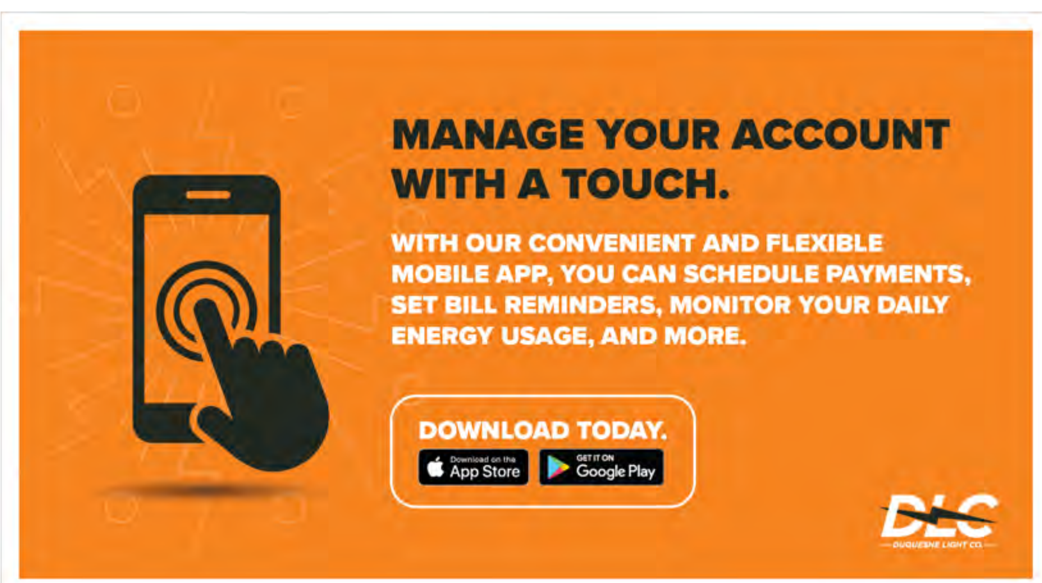
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
- **Meter Reading** – An actual (Act) reading is a reading taken from the meter. An estimated (Est) reading is used when no actual reading is available and is based on past electric usage.
- **Non-Basic Service Charges** – Any category of service not related to basic service.
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

REDACTED

[redacted] **Account #** [redacted]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		120/208V
Meter Readings - kWh		
Present	06/23/2021 Act	14,702.0810
Prior	05/24/2021 Act	14,304.0860
Difference		397.9950
Your Meter Multiplier		40
Total kWh Used		15,919.8000
Meter Readings - kVARh		
Present	06/23/2021 Act	5,504.0630
Prior	05/24/2021 Act	5,337.6780
Difference		166.3850
Your Meter Multiplier		40
kVARh		6,655.4000
Demand Information		
Demand Reading (on-peak)		1.1820
kW (on-peak)		47.2800
PFM		1.0508
Adjusted kW		49.6818
Total Billed Demand		**49.6818**

Current Bill Details

DLC Rate	GMH-Med Commercial Heat > 25		
Price to Compare	$0.0616 / kWh		
DLC Charges			**$659.03**
Customer Charge		$54.52	
PA EEA Surcharge	3714.6200 kWh@ $0.001300	$4.83	
PA EEA Surcharge	12205.1800 kWh@ $0.001500	$18.31	
Energy Distribution	15919.8000 kWh@ $0.013961	$222.26	
Demand Distribution	44.6818 kW@ $6.540000	$292.22	
Smart Meter Charge Thre	MTR@ $0.070000	$0.07	
DSIC Surcharge	4.01%	$23.75	
Pennsylvania Tax Adjustment		-$0.05	
Sales Tax		$43.12	
Supply Charges			**$1,142.72**
Energy Supply	3714.6200 kWh@ $0.042487	$157.82	
Energy Supply	12205.1800 kWh@ $0.052045	$635.22	
Energy Transmission	3714.6200 kWh@ $0.002748	$10.21	
Energy Transmission	12205.1800 kWh@ $0.005180	$63.22	
Demand Transmission	49.6818 kW@ $4.055667	$201.49	
Sales Tax		$74.76	

Total kWh Used	**15,919.8000**
Service Charges	**$1,801.75**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GMH-Med Commercial Heat > 25

The current Price to Compare is listed above in Account Detail and will change quarterly beginning June 1. Your actual PTC may differ based on your specific demand & usage patterns. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

Additional Notifications

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- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- Effective Jun. 1, changes in the Customer Charge, reflecting costs to enhance the competitive energy market in PA, will decrease the monthly bill of a medium commercial customer using 30 kW and 10,000 kWh by about $0.02 or less than 1%.
- Effective Jun. 1, changes in the Energy Efficiency Surcharge, reflecting costs related to the Watt Choices program, will increase the monthly bill of a medium commercial customer using 30 kW and 10,000 kWh by about $2 or less than 1%.
- Estimated Gross Receipts Tax of $99.35 and Estimated PA State Tax of $114.50 are included in your rates.

REDACTED

DUQUESNE LIGHT CO.

Account # [redacted]

Due Date	Amount Due
04/14/2021	$1,240.74

Usage and Demand

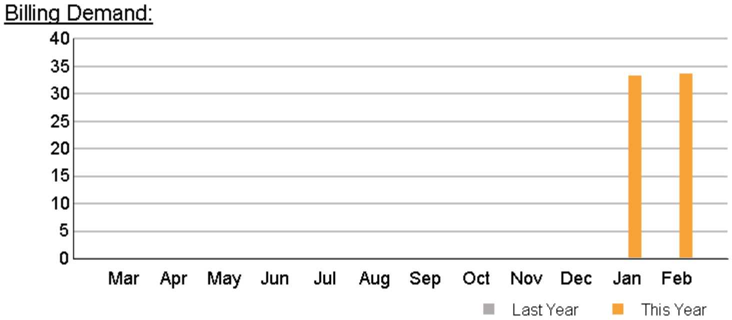
Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	11934	385	31	31
Last Month	18096	584	31	29
Same Month Last Year	0	0	0	0

kWh:

Average Monthly Usage for the last 2 months: 15015 kWh

Total Annual Usage for the last 2 months: 30031 kWh

Billing Demand:



Bill Summary

Bill ID: [redacted] **Date Prepared: 03/14/2021**

Previous Account Balance	$1,828.48
Payment(s) Received as of 02/25/2021	-$1,828.48
Balance Forward	**$0.00**
DLC Charges	$468.18
Supply Charges - [redacted]	$772.56
AMOUNT DUE BY 04/14/2021	**$1,240.74**

Message Center

Introducing your new bill! We've redesigned it to be simple and easy to understand, and we also added color to make it easy to read. For more information on how to read your bill, visit **DuquesneLight.com/newbill.**

Duquesne Light partners with Dollar Energy Fund to provide assistance to customers who struggle to pay their electric bill. If you would like to support the Dollar Energy Fund and your neighbors in need, make a tax deductible monthly pledge at **DuquesneLight.com/dollar**.

DOLLAR ENERGY FUND

MAR: Mark Skosnik - 412-393-7995

Online: www.DuquesneLight.com

Phone: 412-393-7300

BI_POSTAL_20210314PRD.xml

Billing and meter reading details on page 3

Please return this portion with your payment. Please enclose check facing forward. Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-04-14

DUQUESNE LIGHT CO.

Due Date	Amount Due
04/14/2021	$1,240.74

$

USD Amount Enclosed

Account #

[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

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- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

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Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

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- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
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- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.

Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

OSBA-I-3 - Attachment 5 GMHG25 winter

[REDACTED]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		120/240V
Meter Readings - kWh		
Present	03/14/2021 Act	10,887.1180
Prior	02/11/2021 Act	10,588.7620
Difference		298.3560
Your Meter Multiplier		40
Total kWh Used		11,934.2400
Demand Information		
Demand Reading (on-peak)		0.8500
kW (on-peak)		34.0000
PFM		1.0000
Adjusted kW		34.0000
Total Billed Demand		**34.0000**

Current Bill Details

DLC Rate	GMH-Med Commercial Heat > 25		
Price to Compare	$0.0498 / kWh		
DLC Charges			**$468.18**
Customer Charge		$54.53	
PA EEA Surcharge	11934.2400 kWh@ $0.001300	$15.51	
Energy Distribution	11934.2400 kWh@ $0.029609	$353.36	
DSIC Surcharge	3.35%	$14.18	
Pennsylvania Tax Adjustment		-$0.04	
Sales Tax		$30.64	
Supply Charges - [redacted]			**$772.56**
Generation-Trans	11934.2400 kWh@ $0.060500	$722.02	
Sales Tax		$50.54	

Total kWh Used	**11,934.2400**
Service Charges	**$1,240.74**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GMH-Med Commercial Heat > 25

The current Price to Compare is listed above in Account Detail and will change quarterly beginning June 1. Your actual PTC may differ based on your specific demand & usage patterns. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

- Generation/Supply prices and charges are set by the electric generation supplier you have chosen
- The Public Utility Commission regulates distribution prices and services
- The Federal Energy Regulatory Commission regulates transmission prices and services

[redacted]

For questions regarding the supplier portion of your bill, call [redacted]

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.
- Duquesne Light offers energy efficiency programs to help customers save money by conserving energy and reducing demand. To participate or to learn more about these programs, visit www.wattchoices.com.
- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- Estimated Gross Receipts Tax of $68.41 and Estimated PA State Tax of $78.85 are included in your rates.

REDACTED

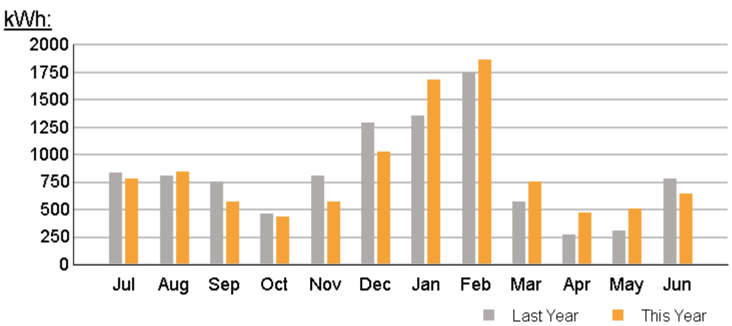
DUQUESNE LIGHT CO.

Account # [redacted]

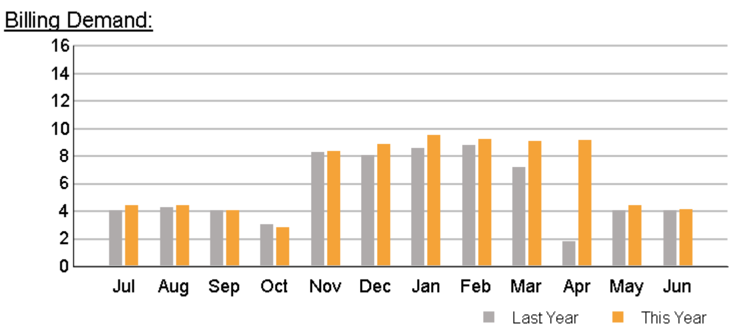
Due Date	Amount Due
07/09/2021	$123.22

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	669	22	30	68
Last Month	525	18	29	60
Same Month Last Year	801	24	34	71



Average Monthly Usage for the last 12 months: 867 kWh
Total Annual Usage for the last 12 months: 10403 kWh



Bill Summary

Bill ID: [redacted] **Date Prepared: 06/23/2021**

Previous Account Balance	$117.39
Payment(s) Received as of 06/10/2021	-$117.39
Balance Forward	**$0.00**
DLC Charges	$72.13
Supply Charges	$51.09
AMOUNT DUE BY 07/09/2021	**$123.22**

Message Center

Signing up for our e-Bill program is fast and easy! Enroll today at **DuquesneLight.com/ebill.**

Duquesne Light shares customer information with some trusted partners that offer programs and services you may find valuable. These trusted service providers operate under confidentiality agreements and cannot share your information with others. For more information, please visit **DuquesneLight.com/privacy**.

BI_POSTAL_20210623PRD.xml

Online: www.DuquesneLight.com **Phone:** 412-393-7300 *Billing and meter reading details on page 3*

Please return this portion with your payment. Please enclose check facing forward.
Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-07-09

DUQUESNE LIGHT CO.

Due Date	Amount Due
07/09/2021	$123.22

$ ____ , ____ . __

USD Amount Enclosed

Account #
[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

Sign up online for any of the following services:

- **E-Billing** - Free service lets you view bills online
- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

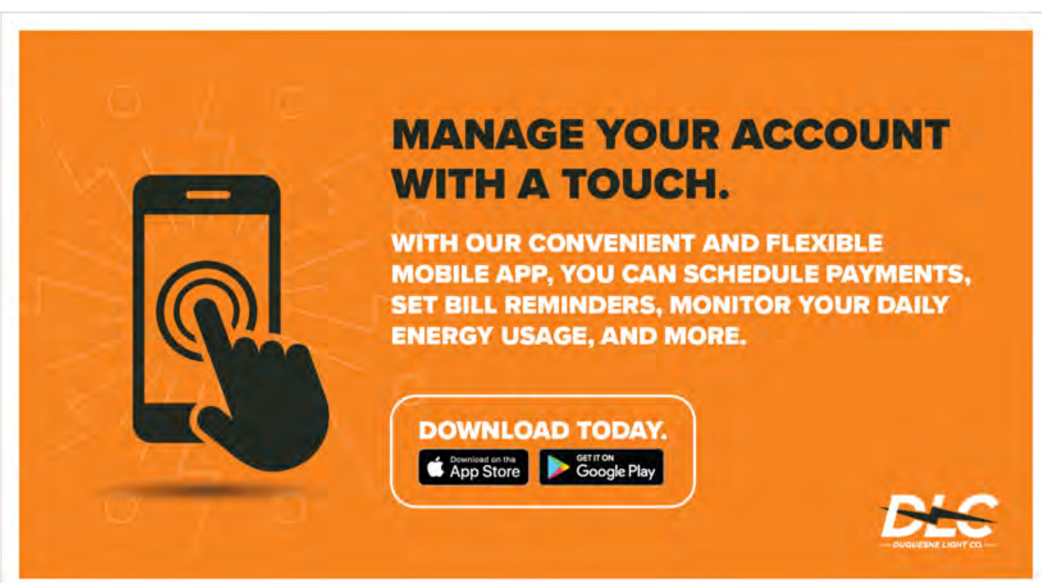
Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

- **Customer Charge** – A monthly basic service charge that includes costs for meter reading, customer billing, service equipment, and other expenses. These expenses are incurred even in months when customers do not use electricity.
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
- **Meter Reading** – An actual (Act) reading is a reading taken from the meter. An estimated (Est) reading is used when no actual reading is available and is based on past electric usage.
- **Non-Basic Service Charges** – Any category of service not related to basic service.
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

REDACTED

[redacted] Account # [redacted]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		120/240V
Meter Readings - kWh		
Present	06/23/2021 Act	54,590.6260
Prior	05/24/2021 Act	53,921.8010
Difference		668.8250
Your Meter Multiplier		1
Total kWh Used		668.8250
Demand Information		
Demand Reading (on-peak)		4.3000
kW (on-peak)		4.3000
PFM		1.0000
Adjusted kW		4.3000
Total Billed Demand		**4.3000**

Current Bill Details

DLC Rate	GMH-Med Commercial Heat < 25		
Price to Compare	$0.0630 / kWh		
DLC Charges			**$72.13**
Customer Charge		$54.51	
PA EEA Surcharge	156.0592 kWh@ $0.001300	$0.20	
PA EEA Surcharge	512.7658 kWh@ $0.001500	$0.77	
Energy Distribution	668.8250 kWh@ $0.013961	$9.34	
DSIC Surcharge	4.01%	$2.60	
Pennsylvania Tax Adjustment		-$0.01	
Sales Tax		$4.72	
Supply Charges			**$51.09**
Energy Supply	156.0592 kWh@ $0.050497	$7.88	
Energy Supply	512.7658 kWh@ $0.052649	$27.00	
Energy Transmission	156.0592 kWh@ $0.002331	$0.36	
Energy Transmission	512.7658 kWh@ $0.006041	$3.10	
Demand Transmission	4.3000 kW@ $2.185000	$9.40	
Sales Tax		$3.35	

Total kWh Used **668.8250**

Service Charges **$123.22**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GMH-Med Commercial Heat < 25

The current Price to Compare is listed above in Account Detail and will change every June and December.Your actual PTC may differ based on your demand & usage kWh. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.
- Duquesne Light offers energy efficiency programs to help customers save money by conserving energy and reducing demand. To participate or to learn more about these programs, visit www.wattchoices.com.
- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- Effective Jun. 1, changes in the Customer Charge, reflecting costs to enhance the competitive energy market in PA, will increase the monthly bill of a small commercial customer using 20 kW and 6,000 kWh by about $0.02 or less than 1%.
- Effective Jun. 1, changes in the Energy Efficiency Surcharge, reflecting costs related to the Watt Choices program, will increase the monthly bill of a small commercial customer using 20 kW and 6,000 kWh by about $1.20 or less than 1%.
- Estimated Gross Receipts Tax of $6.80 and Estimated PA State Tax of $7.83 are included in your rates.

REDACTED

DUQUESNE LIGHT CO.

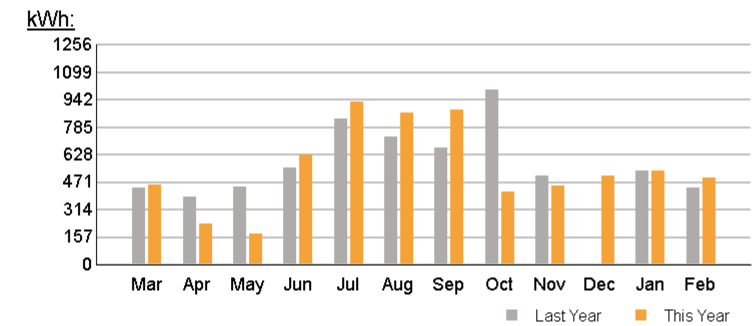
[redacted]

Account # [redacted]

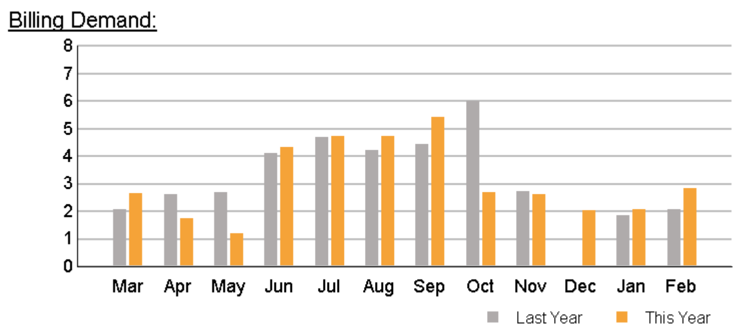
Due Date	Amount Due
03/08/2021	$106.23

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	507	17	29	26
Last Month	551	16	35	33
Same Month Last Year	452	16	29	33



Average Monthly Usage for the last 12 months: 561 kWh
Total Annual Usage for the last 12 months: 6737 kWh



Bill Summary

Bill ID: [redacted] **Date Prepared: 02/18/2021**

Previous Account Balance	$107.77
Payment(s) Received as of 02/03/2021	-$107.77
Balance Forward	**$0.00**
DLC Charges	$77.57
Supply Charges	$28.66
AMOUNT DUE BY 03/08/2021	**$106.23**

Message Center

Introducing your new bill! We've redesigned it to be simple and easy to understand, and we also added color to make it easy to read. For more information on how to read your bill, visit **DuquesneLight.com/newbill.**

Duquesne Light partners with Dollar Energy Fund to provide assistance to customers who struggle to pay their electric bill. If you would like to support the Dollar Energy Fund and your neighbors in need, make a tax deductible monthly pledge at **DuquesneLight.com/dollar**.

DOLLAR ENERGY FUND

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Online: www.DuquesneLight.com **Phone:** 412-393-7300 *Billing and meter reading details on page 3*

DUQUESNE LIGHT CO.

Please return this portion with your payment. Please enclose check facing forward.
Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-03-08

Due Date	Amount Due
03/08/2021	$106.23

$ ____ , ____ . ____

USD Amount Enclosed

Account #
[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

Sign up online for any of the following services:

- **E-Billing** - Free service lets you view bills online
- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

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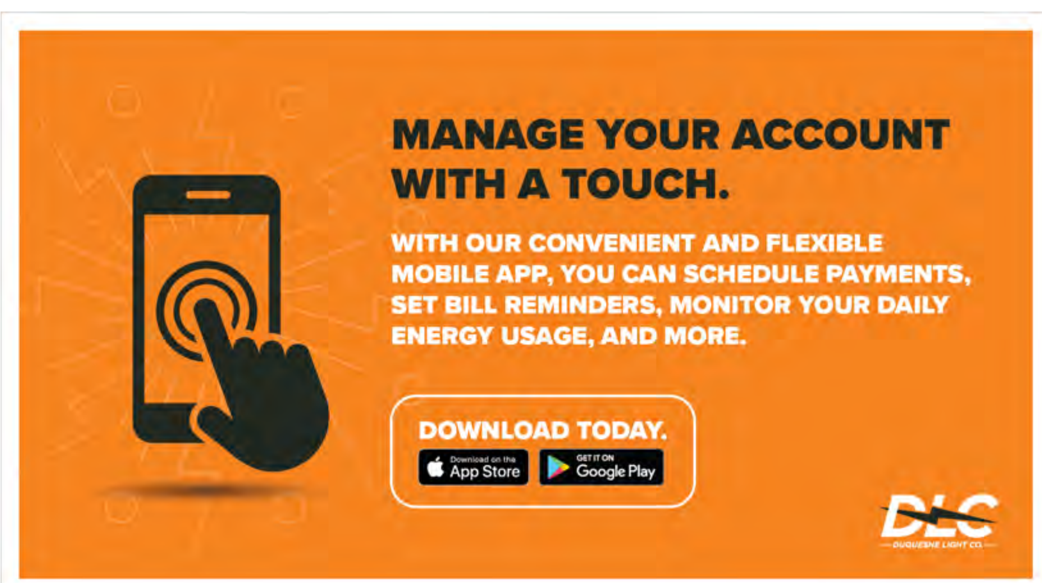
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
- **Meter Reading** – An actual (Act) reading is a reading taken from the meter. An estimated (Est) reading is used when no actual reading is available and is based on past electric usage.
- **Non-Basic Service Charges** – Any category of service not related to basic service.
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

[REDACTED]

[redacted] Account # [redacted]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		120/240V
Meter Readings - kWh		
Present	02/18/2021 Act	22,909.5810
Prior	01/20/2021 Act	22,402.5820
Difference		506.9990
Your Meter Multiplier		1
Total kWh Used		506.9990
Demand Information		
Demand Reading (on-peak)		2.9000
kW (on-peak)		2.9000
PFM		1.0000
Adjusted kW		2.9000
Total Billed Demand		**2.9000**
Total kWh Used		**506.9990**

Current Bill Details

DLC Rate	GMH-Med Commercial Heat < 25		
Price to Compare	$0.0579 / kWh		
DLC Charges			**$77.57**
Customer Charge		$54.49	
PA EEA Surcharge	506.9990 kWh@ $0.001300	$0.66	
Energy Distribution	506.9990 kWh@ $0.029609	$15.01	
DSIC Surcharge	3.35%	$2.35	
Pennsylvania Tax Adjustment		-$0.01	
Sales Tax		$5.07	
Supply Charges			**$28.66**
Energy Supply	506.9990 kWh@ $0.050497	$25.60	
Energy Transmission	506.9990 kWh@ $0.002331	$1.18	
Sales Tax		$1.88	
Service Charges			**$106.23**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GMH-Med Commercial Heat < 25

The current Price to Compare is listed above in Account Detail and will change every June and December.Your actual PTC may differ based on your demand & usage kWh. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.
- Duquesne Light offers energy efficiency programs to help customers save money by conserving energy and reducing demand. To participate or to learn more about these programs, visit www.wattchoices.com.
- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- A change in the Default Service Supply rate that went into effect December 1, increased the monthly bill of an average small commercial customer (using 20 kW and 6,000 kWh) who purchases their generation from Duquesne Light by about $2, or less than 1%.
- A change in the single-phase Smart Meter Charge (see Understanding Your Bill section on page 2), effective January 1, will decrease the overall monthly bill by about $0.18, or less than 1%.
- A change in the poly-phase Smart Meter Charge (see Understanding Your Bill section on page 2), effective January 1, will increase the overall monthly bill by about $1.01, or less than 1%.
- A change in the State Tax Adjustment Surcharge, effective January 1, will decrease your overall monthly bill by about $0.03, or less than 1%.
- Effective January 1, the Distribution System Improvement Charge (see Understanding Your Bill section on page 2) will increase your monthly bill by about $2, or less than 1%.
- Estimated Gross Receipts Tax of $5.86 and Estimated PA State Tax of $6.75 are included in your rates.

REDACTED

DUQUESNE LIGHT CO.

[redacted]

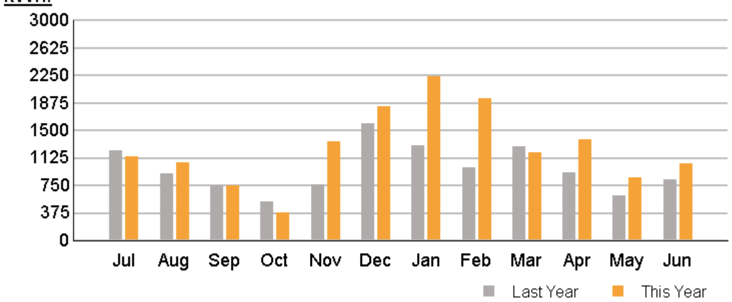
Account # [redacted]

Due Date	Amount Due
07/09/2021	$209.73

Usage and Demand

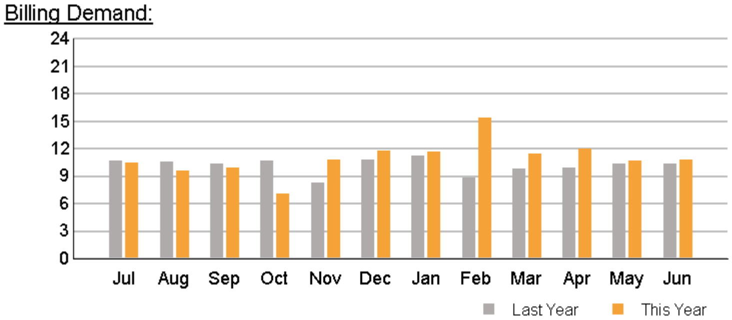
Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	1078	36	30	68
Last Month	886	31	29	60
Same Month Last Year	860	27	32	71

kWh:



Average Monthly Usage for the last 12 months: 1293 kWh
Total Annual Usage for the last 12 months: 15518 kWh

Billing Demand:



Bill Summary

Bill ID [redacted] **Date Prepared: 06/23/2021**

Previous Account Balance	$192.39
Payment(s) Received as of 06/08/2021	-$192.39
Balance Forward	**$0.00**
DLC Charges	$122.68
Supply Charges	$87.05
AMOUNT DUE BY 07/09/2021	**$209.73**

Message Center

Signing up for our e-Bill program is fast and easy! Enroll today at **DuquesneLight.com/ebill.**

Duquesne Light shares customer information with some trusted partners that offer programs and services you may find valuable. These trusted service providers operate under confidentiality agreements and cannot share your information with others. For more information, please visit **DuquesneLight.com/privacy**.

BI_POSTAL_20210623PRD.xml

Online: www.DuquesneLight.com **Phone:** 412-393-7300

Billing and meter reading details on page 3

DUQUESNE LIGHT CO.

Please return this portion with your payment. Please enclose check facing forward.
Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-07-09

Due Date	Amount Due
07/09/2021	$209.73

$, .

USD Amount Enclosed

Account #
[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
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Pittsburgh, PA 15219-1942

Billing and Service Options

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Dollar Energy Fund

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Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

- **Customer Charge** – A monthly basic service charge that includes costs for meter reading, customer billing, service equipment, and other expenses. These expenses are incurred even in months when customers do not use electricity.
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
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- **Non-Basic Service Charges** – Any category of service not related to basic service.
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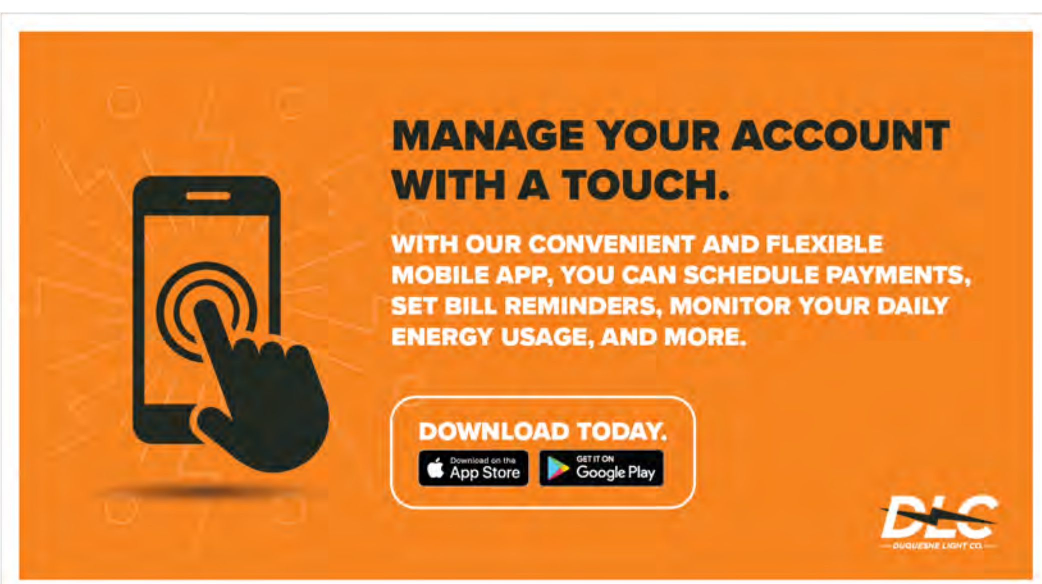
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

Account Detail

[redacted] **Supplier Agreement** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		120/240V
Meter Readings - kWh		
Present	06/23/2021 Act	58,430.5780
Prior	05/24/2021 Act	57,352.5060
Difference		1,078.0720
Your Meter Multiplier		1
Total kWh Used		1,078.0720
Demand Information		
Demand Reading (on-peak)		10.9800
kW (on-peak)		10.9800
PFM		1.0000
Adjusted kW		10.9800
Total Billed Demand		**10.9800**

Current Bill Details

DLC Rate	GM-Medium Commercial < 25		
Price to Compare	$0.0670 / kWh		
DLC Charges			**$122.68**
Customer Charge		$54.51	
PA EEA Surcharge	251.5501 kWh@ $0.001300	$0.33	
PA EEA Surcharge	826.5219 kWh@ $0.001500	$1.24	
Energy Distribution	1078.0720 kWh@ $0.013961	$15.05	
Demand Distribution	5.9800 kW@ $6.540000	$39.11	
DSIC Surcharge	4.01%	$4.42	
Pennsylvania Tax Adjustment		-$0.01	
Sales Tax		$8.03	
Supply Charges			**$87.05**
Energy Supply	251.5501 kWh@ $0.050497	$12.70	
Energy Supply	826.5219 kWh@ $0.052649	$43.52	
Energy Transmission	251.5501 kWh@ $0.008087	$2.03	
Energy Transmission	826.5219 kWh@ $0.008273	$6.84	
Demand Transmission	10.9800 kW@ $0.368667	$4.05	
Demand Transmission	10.9800 kW@ $1.111667	$12.21	
Sales Tax		$5.70	

Total kWh Used **1,078.0720**

Service Charges **$209.73**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GM-Medium Commercial < 25

The current Price to Compare is listed above in Account Detail and will change every June and December.Your actual PTC may differ based on your demand & usage kWh. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

Additional Notifications

- Give to Dollar Energy Fund to help people without heat or light. Make a monthly pledge at www.duquesnelight.com or send a check to Duquesne Light Hardship Fund Donations, 411 Seventh Avenue MD 15-1, Pittsburgh, PA 15219. Your gift is tax deductible.
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- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- Effective Jun. 1, changes in the Customer Charge, reflecting costs to enhance the competitive energy market in PA, will increase the monthly bill of a small commercial customer using 20 kW and 6,000 kWh by about $0.02 or less than 1%.
- Effective Jun. 1, changes in the Energy Efficiency Surcharge, reflecting costs related to the Watt Choices program, will increase the monthly bill of a small commercial customer using 20 kW and 6,000 kWh by about $1.20 or less than 1%.
- Estimated Gross Receipts Tax of $11.56 and Estimated PA State Tax of $13.33 are included in your rates.

REDACTED

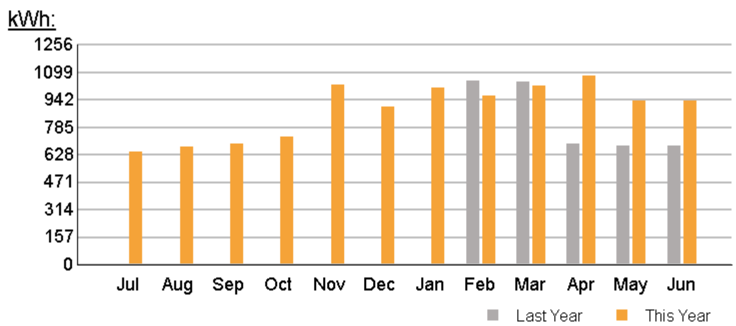
DUQUESNE LIGHT CO.

Account # [redacted]

Due Date	Amount Due
07/26/2021	$157.52

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	948	32	30	68
Last Month	948	33	29	60
Same Month Last Year	694	22	32	71



Average Monthly Usage for the last 12 months: 897 kWh

Total Annual Usage for the last 12 months: 10767 kWh

Bill Summary

Bill ID: [redacted] **Date Prepared: 06/23/2021**

Previous Account Balance	$155.08
Payment(s) Received as of 06/16/2021	-$155.08
Balance Forward	**$0.00**
DLC Charges	$92.79
Supply Charges	$64.73
AMOUNT DUE BY 07/26/2021	**$157.52**

Message Center

Signing up for our e-Bill program is fast and easy! Enroll today at **DuquesneLight.com/ebill.**

Duquesne Light shares customer information with some trusted partners that offer programs and services you may find valuable. These trusted service providers operate under confidentiality agreements and cannot share your information with others. For more information, please visit **DuquesneLight.com/privacy**.

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Online: www.DuquesneLight.com **Phone:** 412-393-7300 *Billing and meter reading details on page 3*

Please return this portion with your payment. Please enclose check facing forward. Make payment payable to Duquesne Light Company in US Currency.

A late charge of 1.25% may be assessed after 2021-07-26

DUQUESNE LIGHT CO.

Due Date	Amount Due
07/26/2021	$157.52

$ ___ , ___ . ___

USD Amount Enclosed

Account #

[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

General Information

Visit us online or call to learn about payment options, or for a copy of our rate schedules. For questions about your bill, please contact us before the bill due date.

Online: www.DuquesneLight.com

Phone: 412-393-7300

Mail: Dept 6-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Billing and Service Options

Sign up online for any of the following services:

- **E-Billing** - Free service lets you view bills online
- **Budget Billing** - Levels out payments across the year
- **Start/Stop Service** - If you're moving and need to have your service turned on or off, you must call Customer Service at 412-393-7300 or visit our website
- **Double Notice Protection** - Sends a payment reminder to you and a person you designate

Dollar Energy Fund

Give to Dollar Energy Fund to help people in our community without heat or light. There are several easy ways to donate and your gift is tax deductible.

Text: Make a one-time donation of $5 by texting POWER to 50000

Online: Visit www.DuquesneLight.com and select "Payment Options" from the Account & Billing menu

Phone: 412-393-7300

Mail: Sign up below to add a monthly pledge to your bill or make a one-time donation by mailing a check to:

Duquesne Light Hardship Fund Donations
Dept 15-1
411 7th Ave Ste 3
Pittsburgh, PA 15219-1942

Understanding Your Bill

- **Customer Charge** – A monthly basic service charge that includes costs for meter reading, customer billing, service equipment, and other expenses. These expenses are incurred even in months when customers do not use electricity.
- **Demand** – A measure of customer or system load requirements over a measured period of time. The actual demand is the highest average kilowatt usage measured amount of all 15-minute intervals during a billing period. The billing demand is the product of the actual demand and the power factor multiplier which identifies the total power provided to the customer.
- **Distribution Charges** – Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system.
- **Distribution System Improvement Charge (DSIC)** – A charge for company investment to improve service quality and increase safety by repairing, improving, or replacing eligible infrastructure used to deliver electricity.
- **DLC Charges** – Services necessary for the physical delivery of electricity service, such as supply, including default service, transmissions and distribution.
- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
- **Meter Multiplier** – The number used to calculate your total electrical usage in kWh (may vary depending on your meter type).
- **Meter Reading** – An actual (Act) reading is a reading taken from the meter. An estimated (Est) reading is used when no actual reading is available and is based on past electric usage.
- **Non-Basic Service Charges** – Any category of service not related to basic service.
- **Smart Meter Charge** – Charges for advanced metering technology and related infrastructure that will provide the ability for features such as two-way communication and interval usage data.
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.

Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

REDACTED

[redacted] **Account #** [redacted]

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		120/240V
Meter Readings - kWh		
Present	06/23/2021 Act	62,787.3580
Prior	05/24/2021 Act	61,839.4960
Difference		947.8620
Your Meter Multiplier		1
Total kWh Used		947.8620

Current Bill Details

DLC Rate	GS-Small Commercial		
Price to Compare	$0.0644 / kWh		
DLC Charges			**$92.79**
Customer Charge		$12.51	
PA EEA Surcharge	221.1678 kWh@ $0.001300	$0.29	
PA EEA Surcharge	726.6942 kWh@ $0.001500	$1.09	
Energy Distribution	947.8620 kWh@ $0.073313	$69.49	
DSIC Surcharge	4.01%	$3.34	
Pennsylvania Tax Adjustment		-$0.01	
Sales Tax		$6.08	
Supply Charges			**$64.73**
Energy Supply	221.1678 kWh@ $0.050497	$11.17	
Energy Supply	726.6942 kWh@ $0.052649	$38.26	
Energy Transmission	221.1678 kWh@ $0.011129	$2.46	
Energy Transmission	726.6942 kWh@ $0.011850	$8.61	
Sales Tax		$4.23	

Total kWh Used **947.8620**

Service Charges **$157.52**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: GS-Small Commercial

The current Price to Compare is listed above in Account Detail and will change every June and December.Your actual PTC may differ based on your demand & usage kWh. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

Additional Notifications

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- Estimated Gross Receipts Tax of $8.69 and Estimated PA State Tax of $10.01 are included in your rates.

OSBA-I-3 - Attachment 10 L

REDACTED

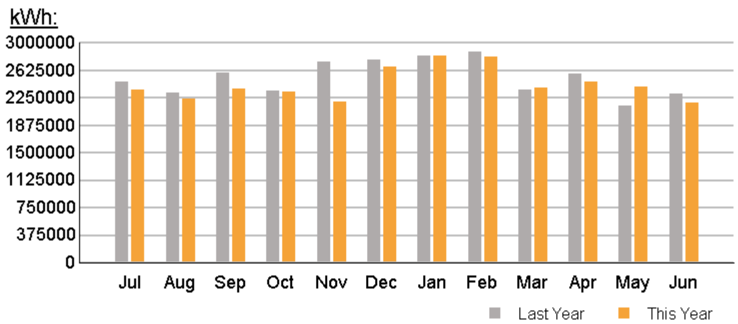
DUQUESNE LIGHT CO.

Account # [redacted]

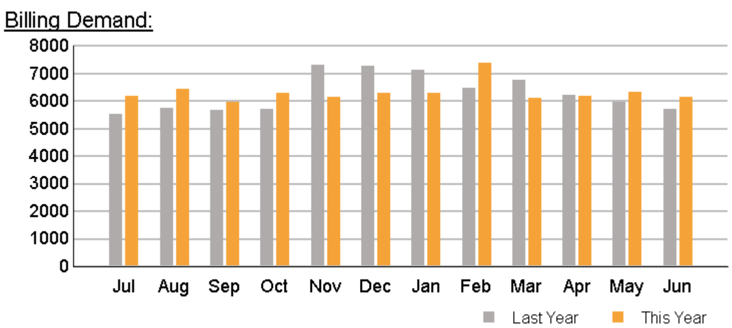
Due Date	Amount Due
07/09/2021	$55,960.12

Usage and Demand

Period	Total kWh Usage	Avg Daily kWh Usage	# of Days	Avg Daily Temp (F)
Current Month	2207306	73577	30	71
Last Month	2434272	78525	31	59
Same Month Last Year	2327843	72745	32	70



Average Monthly Usage for the last 12 months: 2466354 kWh
Total Annual Usage for the last 12 months: 29596250 kWh



Bill Summary

Bill ID: [redacted] **Date Prepared: 06/23/2021**

Previous Account Balance	$57,871.67
Payment(s) Received as of 06/10/2021	-$57,871.67
Balance Forward	**$0.00**
DLC Charges	$55,960.12
AMOUNT DUE BY 07/09/2021	**$55,960.12**

Message Center

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MAR: Barbara Leja - 412-393-2428
Online: www.DuquesneLight.com
Phone: 412-393-7300

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Billing and meter reading details on page 3

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A late charge of 1.25% may be assessed after 2021-07-09

DUQUESNE LIGHT CO.

Due Date	Amount Due
07/09/2021	$55,960.12

$

USD Amount Enclosed

Account #
[redacted]

[redacted]

Please mail payment to:

DUQUESNE LIGHT COMPANY
PO BOX 371324
PITTSBURGH PA 15250-7324

[redacted]

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- **Kilowatt (kW)** – A measure of electrical power that is equal to 1,000 watts.
- **Kilowatt-Hour (kWh)** – The basic unit of electric energy for which most customers are charged. It equals the amount of electricity used by 10, 100-watt light bulbs left on for one hour.
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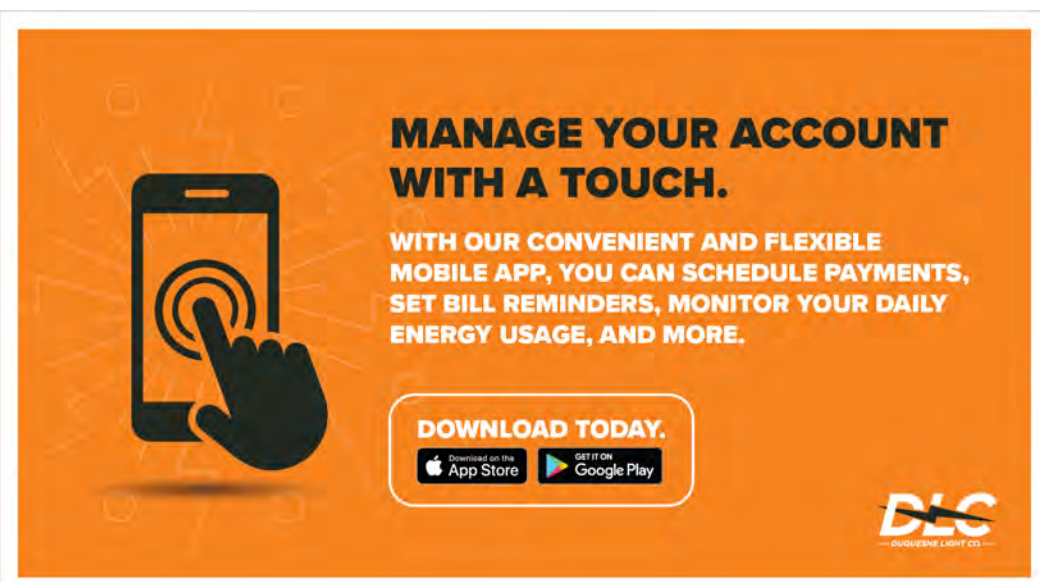
- **Supply Charges** – Basic service charges for generation supply to retail customers.
- **Transmission Charges** – Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system.



Dollar Energy Fund

Monthly Pledge:

☐ $1.00

☐ $2.00

☐ Other: $____.00

DUQUESNE LIGHT CO.

REDACTED

Account Detail

[redacted] **Supplier Agreement ID:** [redacted]

Meter Reading Usage Information

Meter Number		[redacted]
Voltage		2.4/4.16KV
Meter Readings - kWh		
Present	06/22/2021 Act	28,084.8800
Prior	05/23/2021 Act	27,395.0970
Difference		689.7830
Your Meter Multiplier		3200
Total kWh Used		2,207,305.6000
Meter Readings - kVARh		
Present	06/22/2021 Act	9,016.7930
Prior	05/23/2021 Act	8,680.7400
Difference		336.0530
Your Meter Multiplier		3200
kVARh		1,075,369.6000
Demand Information		
Demand Reading (on-peak)		1.7810
kW (on-peak)		5,699.2000
PFM		1.0923
Adjusted kW		6,225.2361
Total Billed Demand		**6225.2362**

Current Bill Details

DLC Rate	L-Large Industrial		
DLC Charges			**$55,960.12**
Customer Charge		$0.01	
Demand Distribution	5000.0000 kW@ $6.980000	$34,900.00	
Demand Distribution	1225.2362 kW@ $13.120000	$16,075.10	
PA EEA Fixed		$281.03	
PA EEA Fixed		$954.91	
PA EEA Variable	845.6669 kW@ $0.400000	$338.27	
PA EEA Variable	2325.5839 kW@ $0.500000	$1,162.79	
Smart Meter Charge Thre	MTR@ $0.070000	$0.07	
DSIC Surcharge	4.01%	$2,153.86	
Pennsylvania Tax Adjustment		-$4.47	
Sales Tax		$98.55	

Total kWh Used **2,207,305.6000**

Service Charges **$55,960.12**

Shopping and Supplier Information

When shopping for electricity with an Electric Generation Supplier, please provide the following information:

Supplier Agreement ID: [redacted]
Rate Schedule: L-Large Industrial

The Price to Compare for your rate class is not calculated because supply rates change hourly, with charges based on your load in those hours. See Rider No. 9, Day-Ahead Hourly Price Service, in our tariff, which can be found at www.duquesnelight.com. For more information & supplier offers visit www.PAPowerSwitch.com and www.oca.state.pa.us.

- Generation/Supply prices and charges are set by the electric generation supplier you have chosen
- The Public Utility Commission regulates distribution prices and services
- The Federal Energy Regulatory Commission regulates transmission prices and services

[redacted]

For questions regarding the supplier portion of your bill, call [redacted]

- [redacted] will provide a separate bill for your generation and transmission.

Additional Notifications

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Additional Notifications

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- SIGN UP FOR AUTOPAY and learn about other convenient payment options by visiting our website www.duquesnelight.com.
- The Price to Compare for your rate class is not calculated because supply rates change hourly, with charges based on your load in those hours. See Rider No. 9, Day-Ahead Hourly Price Service, in our tariff, which can be found at www.duquesnelight.com.
- Effective Jun. 1, changes in the costs to enhance the competitive energy market in PA, will increase the monthly bill of a large industrial customer using 500 kW and 200,000 kWh by about $0.02 or less than 1%.
- Effective Jun. 1, changes in the Energy Efficiency Surcharge, reflecting costs related to the Watt Choices program, will increase the monthly bill of a large industrial customer using 500 kW and 200,000 kWh by about $298 or 2%.
- Estimated Gross Receipts Tax of $3,295.83 and Estimated PA State Tax of $3,798.59 are included in your rates.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: Yvonne Phillips, Katherine Scholl, and David Ogden

OSBA-I-8

8. Reference Statement No. 6, master metering proposal:

a. Please provide a listing of all new residences constructed in the Company's service territory that would have qualified for the proposed master metering arrangement in the past five years, showing the number of buildings, the number of residential units, an indicator as to whether the building has electric heat, and the estimated annual electric consumption for each.

b. Please provide the Company's comparative analysis of the per-residence electric service cost (total bill basis) for service provided through the proposed master metered arrangement and service provided through regular residential service with customer assistance program credits. Please include supporting workpapers.

c. Please provide the Company's estimate of the construction cost savings of adopting a master meter for a new residential building, compared to the cost of installing individual meters, both per unit and as a percentage of the average unit construction cost for new buildings. Please include supporting workpapers.

d. Please provide the Company's estimate of the number of buildings and the number of units for each of the next five years, by rate class, with supporting assumptions and workpapers. Please explain how this estimate is reflected in the Company's load forecasting.

e. Please provide the Company's estimate of the billing load profile for the average unit within a qualifying building by rate class, showing seasonal distribution billing demands, seasonal transmission billing demands, and seasonal energy consumption.

f. Please provide all correspondence related to the collaborative meetings held on June 19, 2019 and February 24, 2021, as well as meeting invitation lists, meeting attendance lists, and meeting minutes. Please include a copy of the presentation circulated at the February 24, 2021 meeting.

g. Please provide the factual basis for the understanding expressed at page 7 lines 14 to 17 of the referenced testimony. Please also discuss whether this understanding applies to buildings owned by public housing authorities or to all buildings that would be eligible for the proposed treatment.

h. Please provide the Company's estimate of its annual EE&C spending plans for new buildings qualifying for the proposed master metering arrangement for the current EE&C plan period.

i. In MS Excel electronic format, please provide a monthly history for the past five years of the Company's default service rate for each of the following rate classes: RS, RH, GS, GM<25 kW, GM>=25 kW, GMH, GL and GLH rate classes.

j. Please provide the current number of customers, the number of units, and the estimated annual kWh consumption of master metered residential customers taking service under non-residential rate class tariffs, by rate class as defined in the cost allocation study.

Response:

a. The Company is unable to provide the information requested because it does not know which recently-constructed buildings may hypothetically have met the master metering eligibility criteria proposed in this proceeding.

b. The Company lacks the data required to perform the requested analysis.

c. The Company does not know the construction cost impacts of master metering versus individual metering.

d. Assuming that "buildings" as used in this question refers to new residential buildings with master metering arrangements under the Company's proposed Rule 41.1: The Company does not have the requested projections.

e. The Company does not maintain this type of analysis. See part (b).

f. See Nationwide-I-9.

g. This understanding is based on input from external stakeholders, as well as the Company's experience working with public housing providers through its energy efficiency programs.

h. The Company has no such estimate.

i. Please see OSBA-I-8 Attachment 1 for the Company's default service rates for the last five years for the following rate classes: RS, RH, RA, GS, GM<25, GMH<25, GM>25<200, and GMH>25<200. Currently, customers on rate classes GM>200, GMH>200, GL and GLH are on Hourly Price Service under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service.

j. The Company does not know the number of residential units in master metered buildings in its service territory.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: David Ogden and Howard Gorman

OSBA-I-11

11. Reference: Rate design for GMH and GLH customers:

a. Please specify the historical months for the NCP for Rates GMH and GLH, as used to develop the distribution demand allocators.

b. If allocated distribution costs for the GMH and GLH rate classes are dependent on the winter class NCP demands, please explain why no demand charge applies to the winter season.

c. In light of your response to part (a), please explain why it is appropriate to apply a (full) demand charge to winter season demands for Rates GM and GL.

d. Does the absence of a demand charge in the winter for Rates GMH and GLH implicitly provide a larger potential credit for net metered service than that for Rates GM and GL? Please explain your response.

e. Please explain generally why the Company believes it is reasonable and necessary to retain heat and non-heat rate classes for the purpose of setting distribution rates.

f. Please specify when the GMH and GLH classes were established and provide the Company's contemporaneous rationale for establishing those rate classes.

Response:

a. The annual NCP values at Transmission level, for each class, for years 2005-2019, are shown on Exhibit 6-9E, lines 35-49. The table below provides the time of the class NCPs.

	GMH<25		GMH>25		GLH	
Year	NCP	Date/Time	NCP	Date/Time	NCP	Date/Time
2019	15.1	01/31/19 @ 9AM	52.7	01/31/19 @ 8AM	78.2	01/31/18 @ 8AM
2018	12.6	01/06/18 @ 3PM	62.5	01/05/18 @ 11AM	84.3	01/05/18 @ 8AM
2017	10.5	12/27/17 @ 9AM	58.1	02/01/17 @ 1PM	86.0	01/09/17 @ 9AM
2016	12.9	02/14/16 @ 9AM	56.0	12/16/16 @ 11AM	90.7	01/19/16 @ 8AM
2015	15.3	02/15/15 @ 9AM	61.5	02/16/15 @ 10AM	98.7	02/16/15 @ 9AM
2014	15.0	01/07/14 @ 11AM	65.1	01/07/14 @ 11AM	104.3	01/07/14 @ 9AM
2013	11.7	01/23/13 @ 12PM	57.6	01/23/13 @ 12PM	98.2	01/23/13 @ 8AM
2012	11.1	01/20/12 @ 12PM	50.3	01/20/12 @ 12PM	96.9	07/18/12 @ 12PM
2011	12.2	01/22/11 @ 9AM	56.4	01/24/11 @ 10AM	103.6	01/24/11 @ 9AM
2010	14.0	01/02/10 @ 3PM	60.2	01/30/10 @ 10AM	106.3	01/29/10 @ 7AM
2009	16.9	01/17/09 @ 8AM	60.1	01/16/09 @ 11PM	107.4	02/05/09 @ 7AM
2008	17.9	12/06/08 @ 3PM	55.2	01/26/08 @ 3PM	105.3	02/21/08 @ 7AM
2007	16.1	01/20/07 @ 3PM	63.6	02/10/07 @ 3PM	110.6	02/08/07 @ 7AM
2006	11.9	02/18/06 @ 3PM	55.7	02/18/06 @ 3PM	98.4	08/03/06 @ 11AM
2005	12.9	01/22/05 @ 3PM	60.3	01/22/05 @ 3PM	101.8	01/28/05 @ 7AM

b. As reflected in the table to part (a), GMH and GLH rate classes are predominantly dependent on the winter class NCP demands. It should be noted that the Company has consistently provided the complementary electric space heating rates for over 40 years. Over the course of this period, the Company has not billed for demand during the winter season, only for usage. For each rate class, roughly 10% of eligible GM and GL customers have elected the space heating rate. The Company designed the GMH and

GLH rate classes to be revenue neutral from a base distribution revenue perspective. If the Company were to consider the presence of a winter demand charge under the current construct, the Company would have to either reduce the fixed customer charge and/or the variable kWh rate in order for revenues to remain neutral.

c. Part (a) does not address Rates GM and GL specifically. Regardless, the Company needs to have facilities in place throughout the year. The present rate design includes demand rates based on year-round monthly billing determinants. While the Company could consider a different rate design, this could have a significant cost shift among customers. In addition, the use of Contract Demand in the tariff smooths out billing to some extent.

d. The billing provisions of Rider No. 21 – Net Metering Service states that a "customer-generator will receive credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the <u>full retail rate</u> consistent with Commission regulations." Based simply on this provision alone, during the winter months, rate GMH/GLH could technically have a larger <u>full retail rate</u> than Rate GM/GL, because customer-generators are still responsible for the customer charge, demand charge and other applicable charges under the applicable rate schedule.

e. See part (b) and (c). A different rate design could have a significant cost shift among customers.

f. Rate GMH (formerly known as Rate HG), was established for rates effective February 10, 1971, as ordered by the Public Utility Commission Docket No. C.18808 dated January 22, 1971. Rate GLH (formerly known as Rate HN) was established for rates effective January 19, 1973, which was created to clarify the application of the Seasonal All-Electric Rate.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: David Ogden and Katherine Scholl

OSBA-I-12

12. Reference Rate GMH eligibility:
    a. Please indicate whether the kWh equivalent for heat loss associated with supplemental renewable energy sources is included in the 25% calculation, and provide the rationale for the approach.
    b. Please provide a representative sample calculation of customer eligibility for Rate GMH for a customer with a rooftop solar installation.

Response:

a. Per the Company's tariff, the 25% applies to "the customer's entire electric energy requirements during the heating season" (emphasis added).

b. The Company does not have the representative calculation requested. The Company construes Rate GMH eligibility criteria liberally, and will generally place an eligible customer on Rate GMH upon customer request, where the customer demonstrates that the Company's electric service is the sole method of space heating (e.g., through proof of equipment installation and/or winter heating load profile).

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: David Ogden

OSBA-I-27

27. Reference Rider No. 3:

a. Please define the purpose of this rider, and the net cost or benefit relative to regular tariff service for the FPFTY.

Response:

Rider No. 3 – School and Governmental Service Discount Period allows for the Late Payment Charge specified in the applicable rate to be added to the net amount for failure to make payment of Company charges within thirty days from the mailing date, versus the fifteen day period that's reflected in the Late Payment Charge provision for each applicable rate schedule. The Company does not track the estimated net cost of benefit relative to regular tariff service because it does not know the amount of Rider No. 3 customers' bills that they would have been paid between 15-30 days after the customers' bill due date.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: Howard Gorman

OSBA-I-33

33. Reference functionalization and allocation of underground conductors, DLC Statement No. 15 at page 18:

a. Please explain generally why the allocated cost per unit of overall class NCP demand for both primary and secondary demand related costs for underground conductors is far lower for the residential classes than for the non-residential classes. Do underground conductors disproportionately serve non-residential customers?

b. Please provide supporting calculations or a reference for the segregation of underground conductors and conduit costs between radial, network and URD.

c. Please provide the basis for the determination that 97.5 percent of the residential class does not use the underground radial system. Please also provide the corresponding values for the other rate classes.

Response:

a. It appears the question refers to information presented on Exhibit 6-3, line 7 regarding Primary voltage assets and line 8 regarding Secondary voltage assets. The Company did not examine this question specifically, however, the following factors may be contributing to this effect:
   - The Company separates its distribution assets among Non-Network, serving all customers; Network, serving only non-residential; Radial, serving primarily

non-residential; and URD, serving only residential. These components have different cost structures.

- Residential customers are physically closer to each other than non-residential, which could allow more efficiency in asset deployment.
- Regarding Secondary, the load-carrying capacity of the minimum system is excluded from demand-related costs.

b. The segregation of underground conductors and conduit costs among radial (72%), network (14%) and URD (14%) is an estimate provided by Company engineering.

c. The estimate that 97.5 percent of the residential class does not use the underground radial system was provided by Company engineering. This adjustment applies only to the residential classes.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: Howard Gorman

OSBA-I-35

35. Reference Exhibit 6-9H:

a. Please provide the basis for the blending factors used in this analysis.

b. Please provide the basis for the labor hours values used in this analysis. Please indicate whether the estimates include travel to site time.

c. Please provide the basis for the fringe markup, and indicate whether it includes a provision for vacation, illness, and employee training downtime.

Response:

a. The blending ratio should have been 33% Poly/ 67% Alpha, based on the following meter counts provided by the Company. The Company will address this in rebuttal testimony.

Type	Total	In Classes with One Type	In Blended Classes
Poly	22,287	8,267	14,020
Single	595,500	566,782	28,718
Alpha/ERT	148		148
Total	**617,935**	**575,049**	**42,886**

b. The labor hours are estimated hours as of December 2019. The labor hours include travel time to and from the job sites. The hourly labor rates are from the Collective Bargaining Agreement and will be effective starting October 1, 2021.

c. The fringe markup of 26.70% represents actual costs for December 2019 expressed as a percent of direct salary, for the following items: Employer payroll taxes- 6.17%; Health care- 7.49%; Pension/ 401K- 11.78%; FAS 106 (retirement benefits other than pension)- 0.16%; Miscellaneous- 0.91%; Workers' Compensation- 0.18%. Neither the fringe rate or the hourly labor rate are adjusted for vacation, illness, holiday or employee training downtime.

Duquesne Light Company
Docket No. R-2021-3024750

Interrogatories of the
Office of Small Business Advocate

Set I

Witness: Howard Gorman

OSBA-I-36

36. Reference Exhibit 6-9C:

a. Please provide minimum system calculations for primary system costs for Accounts 365, 366/367 Radial, 366/367 Network, 366/367 URD, and 368.1.

b. Please explain why the Company chooses to classify primary system distribution plant as 100 percent demand-related, in light of the NARUC Electric Utility Cost Allocation Manual and Commission precedent.

Response:

a. The Company did not perform a Minimum System study for the Primary portions of any accounts, because the Primary portion of the distribution system was classified as 100% demand-related, as the Company has done since at least 2005. The information to perform such a study is not readily available, and it would take significant time and effort to do a study.

b. The NARUC Manual, January 1992 edition, page 90, states, "The customer component of distribution facilities is that portion of costs which varies with the number of customers." The Primary Distribution system includes assets rated 4kV through 23kV. Very few customers are served at Primary voltage levels, most are connected to the system through the Secondary distribution system. Therefor the number of customers has almost no effect on the cost of the Primary system, and it is not appropriate to classify any portion as customer-related.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024296**
DUQUESNE LIGHT COMPANY	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Surrebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibits IEc-S1 and IEc-S2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 10, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3024750**
	:	
Duquesne Light Company	:	
1308(d) Proceeding	:	

CERTIFICATE OF SERVICE

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

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CAUSE-PA Statement 1, Harry Geller

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

DIRECT TESTIMONY OF HARRY GELLER

ON BEHALF OF

THE COALITION FOR AFFORDABLE UTILITY SERVICES AND

ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

June 16, 2021

PREPARED DIRECT TESTIMONY OF HARRY GELLER

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

A. My name is Harry S. Geller. I am an attorney. I am retired as the Executive Director of the Pennsylvania Utility Law Project (PULP), but have maintained an office at 118 Locust St., Harrisburg, PA 17101 for the purpose of providing consulting services and assistance to low income individuals and the organizations which represent them in utility and energy matters.

Q. Briefly outline your education and professional background.

A. I received my B.A. degree from Harpur College, State University of New York at Binghamton in 1966, and a J.D. degree from Washington College of Law, American University in 1969. Upon graduation from law school, I entered the Volunteers in Service to America (VISTA) program, where I was assigned to the New York University Law School. I took courses in the Law School's Urban Affairs and Poverty Law program and worked with the Community In Action Program on the West Side of Manhattan in New York City from 1969-1971. In 1971, I started as a Staff Attorney for the New York City Legal Aid Society, Criminal Court, and Supreme Court Branches in New York County. In 1974, I moved to Pennsylvania and began working for Legal Services, Incorporated (LSI). LSI was a civil legal aid program serving Adams, Cumberland, Franklin, and Fulton Counties. I worked at LSI from 1974-1987 first as a Staff Attorney, then as Managing Attorney, and ultimately became Executive Director. Through a restructuring with other legal services programs, LSI became part of what is now known as MidPenn Legal Services and Franklin County Legal Services.

In 1988, I was hired to be the Executive Director of PULP, a statewide legal aid project dedicated to protecting the rights of low income utility customers. At PULP, I represented low income individuals with utility and energy concerns and supported organizations advocating for low income households in utility and energy matters. As the Executive Director, I consulted and co-counseled on a wide variety of individual utility consumer cases, and I participated in task forces, work groups and advisory panels, including serving as chair of the Department of Human Services' LIHEAP Advisory Committee and the Pennsylvania Public Utility Commissions' Consumer Advisory Committee. I frequently trained communities, legal aid staff, and advocacy groups across Pennsylvania about the various utility and energy matters affecting Pennsylvania's low income population. I retired from PULP on June 30, 2015. Since that time, I have continued to provide consulting services for PULP and its clients, as well as other organizations serving the low income community.

In sum, I have almost 50 years' experience working on behalf of households in poverty, including the past 30 years focusing specifically on utility and energy issues affecting low income consumers. My resume is attached as Appendix A.

Q. Please describe the focus of your work over the past fifty years, including relevant work experience on issues of low income families' ability to afford essential services such as utilities?

A: I have represented low income individuals and organizations serving low income populations in a wide variety of legal matters, including family law, public benefits, unemployment compensation, utility shut-offs, debtor/creditor, and housing-related disputes. Over the past 30 years, my focus has been to ensure that low income households can connect to, afford, and maintain utility and energy services.

In all of these legal matters, I worked almost exclusively on behalf of individuals and households that subsist on incomes at or below 150% of the Federal Poverty Level (FPL). Through this work, I have had a close view of the daily lives of countless of our poorest citizens. I have spent thousands of hours assisting clients, combing through their budgets to see whether it is even possible to make ends meet. Over the years, I have consistently seen the near total absence of the ability of low income families to afford the most basic monthly necessities with the incomes they have, even assuming heroic self-control and conscientious budgeting and spending. Almost every month, my clients faced the stark reality of having to choose which bills they can forgo with the least drastic consequences.

In addition to my deep understanding of the daily monetary struggles facing poor families, I have an extensive knowledge of the array of programs designed to allow low income individuals to afford utility service. While at PULP, I was involved in hundreds of proceedings evaluating the effectiveness of programs that are intended to reduce low income households' energy burdens and help them conserve energy through efficiency and weatherization. I have spent thousands of hours identifying the problems in Universal Service programs and making recommendations for changes to these programs to better serve low income consumers. This advocacy ultimately led to the recognition of the need to develop integrated programs for low income consumers. Furthermore, I played an instrumental role in the development, oversight, and monitoring of the initial pilot and then the statutorily required low income Universal Service Programs, each of which is structured to provide a different form of assistance to low income customers to enable those customers to afford and maintain basic service.

For example, the Customer Assistance Program (CAP) provides alternatives to traditional collection methods for low income, payment troubled utility customers, allowing participants to receive a more affordable bill and earn forgiveness on arrears in exchange for making in-full payments on their discounted bill. In turn, the Low Income Usage Reduction Program (LIURP) is a targeted weatherization program designed to assist low income households with the highest energy consumption, payment problems, and arrearages to reduce their overall energy consumption. CAP and LIURP work in tandem and are designed to assist low income households in maintaining affordable utility services and safe living environments while reducing utility collection, thereby benefitting other ratepayers and the communities in which they live and work.

Q: Have you testified in any proceeding before the Pennsylvania PUC?

A: Yes. I have presented testimony in many proceedings before the PUC. A complete list is included in my resume, which is attached as Appendix A.

Q: For whom are you testifying in this proceeding?

A: I am testifying on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA).

Q: What is the purpose of your testimony?

A: CAUSE-PA intervened in this proceeding to ensure that the proposed rate increase and rate design will not adversely affect Columbia Gas of Pennsylvania, Inc.'s (Columbia, CPA, or the Company) low income customers' ability to connect to, maintain, and afford natural gas service, which is essential for heating, cooking, and hot water – all critical components to a safe and healthy home.

Q: How is your testimony organized?

A: My testimony is divided into four substantive sections and one section summarizing my proposals and recommendations. In section I, I discuss the financial impact that Columbia's proposed residential rate increase will have on its low income ratepayers, particularly in the face of the current pandemic and economic crisis. According to the Company's own estimates, nearly one quarter of its residential customers were categorized as low income customers even before the economic devastation of the pandemic. These households struggle to pay for basic life necessities. Further increasing the cost of natural gas service will increase already high levels of unaffordability for tens of thousands of customers, leading to increased terminations and associated health risks. As I will explain, Columbia's current universal service programs are inadequate to address the affordability gap for economically vulnerable customers. Regardless of whether any rate increase is ultimately approved, Columbia must improve its universal service programs to ensure that low income consumers are able to maintain service to their home.

In section II, I discuss Columbia's proposed rate design, which seeks to recover a large portion of the residential cost of service through a fixed monthly customer charge. I will also discuss Columbia's proposed Revenue Normalization Adjustment (Rider RNA), which would adjust non-gas distribution revenue based on a per customer basis. In short, Columbia's high fixed charges and its proposed Rider RNA undermine energy efficiency efforts and deprive households of the ability to gain economic savings through the adoption of energy efficient products and practices. Thus, Columbia's proposed Rider RNA should be rejected and, to the extent that any of the proposed rate increase is found to be just and reasonable, it should be added to the volumetric charge - and not the fixed charge portion of the bill.

In section III, I will address Columbia's language access procedures. Columbia has implemented several tools to help ensure that limited English proficiency customers are able to understand communications with the Company via telephone and website. These tools can be effectively utilized to bolster the Company's universal service outreach process and ensure that consumers in limited English communities are able to access programing.

In section IV, I will address Columbia's security deposit retention policies. Columbia's tariff only provides security deposit waivers for customers who enroll in CAP. This should be amended to include all confirmed low income customers who are income eligible for CAP. Columbia has indicated that it is currently holding security deposits from confirmed low income customers, and I recommend they be returned and that Columbia develop a process to screen for and return all deposits held from confirmed low income customers.

Finally, in section IV, I will summarize the recommendations and proposals which I provided throughout my direct testimony.

Q: Please summarize the Company's requested rate increase as it applies to residential customers.

A: On March 30, 2021, Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") submitted a rate filing, Supplement No. 325 to Tariff Gas Pa. P.U.C. No. 9, which proposes to increase overall rates by approximately $98.3 million per year. At the most recently effective gas cost rates, the total bill for a residential customer who purchases 70 therms of gas from Columbia per month would increase nearly $15 per month from $100.77 to $115.37 per month, or by 14.49%.[1] The Company's proposal would be Columbia's fifth rate increase since 2015.

Q: As a preliminary matter, do you support the Company's requested rate increase?

A: No. Now is not the time to raise rates for essential utility services. Throughout the pandemic, low income households have experienced disproportionate health and economic harm – with greater job and wage losses, increased food insecurity, and accrual of unprecedented

[1] See Columbia Cover Letter to Rate Filing, March 30, 2021.

levels of debt for basic life necessities.[2] While the general economic outlook has begun to turn around, low income communities continue to face stark challenges, and are at risk of being left behind in the recovery. Increasing rates at this time – without substantial mitigation to fully remediate existing unaffordability – would be unjust, unreasonable, and contrary to the public interest.

As a foundational principle, I do not believe that rates are just and reasonable if they are not also reasonably affordable for those seeking to obtain or maintain service. As I will explain below, Columbia's existing rates – including rates for low income customers enrolled in Columbia's Customer Assistance Program (CAP) – are categorically unaffordable for low income customers, and are therefore neither just nor reasonable. Before approving ***any*** increase in rates, Columbia must be required both to fully address and remediate *existing* rate unaffordability to ensure that low income households can reasonably afford to maintain natural gas service to their home and also to mitigate the effect that the potential rate increase may have.

[2] See Diana Hernández, Yumiko Aratani, Yang Jiang, Energy Insecurity among Families with Children, National Center for Children in Poverty, January 2014, at 3, available at: http://www.nccp.org/publications/pub_1086.html ; Liz Szabo and Hannah Recht, The other COVID-19 risk factors: How race, income, ZIP code can influence life and death, USA Today, April 22, 2020, available at: https://www.usatoday.com/story/news/health/2020/04/22/how-coronavirus-impacts-certain-races-income-brackets-neighborhoods/3004136001/ ; see also Vanessa Williams, Disproportionately black counties account for over half of coronavirus cases in the U.S. and nearly 60% of deaths, study finds, Washington Post, May 6, 2020, available at: https://www.washingtonpost.com/nation/2020/05/06/study-finds-that-disproportionately-black-counties-account-more-than-half-covid-19-cases-us-nearly-60-percent-deaths/ .

I. RATE IMPACT ON LOW INCOME HOUSEHOLDS

Q: How many customers in Columbia's service territory are considered to be low income customers?

A: Pennsylvania's large public utilities track and classify their low income customer population two ways: estimated low income customers and confirmed low income customers.[3] While the number of estimated and confirmed low income customers in Columbia's service territory is sure to grow due to the economic impact of the COVID-19 pandemic, available data shows that the Company had a substantial number of both estimated and confirmed low income customers even before the crisis. To be considered low income, a household must have income which is at or below 150% of the federal poverty level (FPL). For context, a family of four with income at or below 150% FPL has a *maximum* gross annual income of $39,750 – or $3,312.50 per month.[4]

As of March 2021, Columbia estimates that nearly one in four – 96,648 out of 404,693 or approximately 23.8% of its residential customers are low income customers.[5] This is Columbia's "estimated low income customer" count, which the Company calculates using residential customer counts and census data provided by the Bureau of Consumer Services.[6]

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[3] See Pa. PUC, BCS, 2019 Report on Universal Service Programs & Collections Performance, at 2,4 (Sep. 2020) (herein 2019 Universal Service Report).

[4] See US Dept. of Health & Human Services, HHS Poverty Guidelines for 2021, https://aspe.hhs.gov/poverty-guidelines.

[5] See CAUSE-PA to Columbia (CPA) I-1, I-2.

[6] See CAUSE-PA to CPA I-6.

Columbia also tracks "confirmed low income customers."[7] As of March 2021, Columbia reported 69,554 of its residential customers – approximately 17.2% – were classified as "confirmed low income."[8] This means the Company has verified the customer's household income for participation in a universal service program or the customer reported to the Company that their income is at or below 150% FPL.[9]

The estimated low income customer figure (23.8%) presents a more accurate picture of Columbia's pre-pandemic low income customer population. While both metrics show that a significant number of customers are low income, the confirmed low income customer count provides only a limited assessment of the low income population – counting only the number of customers who have already affirmatively obtained assistance or otherwise reported their income level to the Company. For purposes of evaluating the effectiveness of its universal service program participation and outreach, it is more accurate to utilize the census-based estimated low income customer counts – which are proportionate to the number of residential customers in each county within Columbia's service territory. Nevertheless, regardless of the measure applied, there are a substantial number of low income customers (17.2% confirmed, 22.8% estimated) in Columbia's service territory.

[7] See 2018 Universal Service Report at 5.

[8] CAUSE-PA to CPA I-1, I-3.

[9] CAUSE-PA to CPA I-3.

Q: How much income must a household earn each month to be considered low income?

A: Columbia's CAP requires that customers have income at or below 150% FPL to qualify for the program, while its Hardship Fund program and Low Income Usage Reduction Program (LIURP) are available for customers with household income up to 200% FPL.[10]

The FPL is a measure of poverty based exclusively on the size of the household, but not the composition of the household (i.e., whether the household consists of adults or children) or the cost of living in a given geographic region. As a baseline, a family of four at 150% FPL has a gross annual income of $39,300, while a family of four at 50% FPL has a gross annual income of $13,100.[11] Table 1 shows the percentage of FPL by household size.

Table 1: Percentages of Federal Poverty Levels by household size and income[12]

Household/ Family Size	25%	50%	75%	100%	125%	150%	200%
1	$3,220	$6,440	$9,660	$12,880	$16,100	$19,320	$25,760
2	$4,355	$8,710	$13,065	$17,420	$21,775	$26,130	$34,840
3	$5,490	$10,980	$16,470	$21,960	$27,450	$32,940	$43,920
4	$6,625	$13,250	$19,875	$26,500	$33,125	$39,750	$53,000

For context, a full time (40 hour/week) worker making minimum wage ($7.25/hour) has a gross annual income of $15,080 - assuming no time off. This would be 68.7% FPL for a single parent with two children or 138.1% FPL for a family of four with two parents working minimum

[10] Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2019-2021
[11] U.S. Dept. of Health and Human Services, 2021 U.S. Federal Poverty Guidelines, available at https://aspe.hhs.gov/poverty-guidelines .
[12] Id.

wage jobs. This is substantially less than a household needs to meet their basic expenses in any of the counties in Columbia's service territory.[13]

A benchmark often used to assess how much income a household needs to live without assistance in Pennsylvania is called the Self Sufficiency Standard. This is a tool that measures the income that a family must earn to meet their basic needs and consists of the combined cost of 6 basic needs – housing, child care, food, health care, transportation, and taxes – without the help of public subsidies.[14] Unlike the federal poverty level, which does not change based on geographic location or family composition, the Self Sufficiency Standard accounts for the varied costs of these six basic needs in different geographical areas and for differently aged household members.[15] For reference, the *average* Self Sufficiency Standard in Columbia's service territory for a family of four with two adults, one infant, and one preschooler is approximately $60,277 per year – over $20,000 more than a household of four with income at 150% FPL makes in a given year.[16]

The income levels for most of Columbia's confirmed low income customers do not even approach these levels. The average annual income for the Company's confirmed low income customers is $17,958 and the average income for the Company's CAP customers is just $14,974.[17] These customers have far less than the amount needed to be self-sufficient and to live without financial assistance. Any increase in the cost of necessities, including the rates for natural gas for

[13] Self Sufficiency Standard, http://www.selfsufficiencystandard.org/Pennsylvania.

[14] See PathWays PA, Overlooked and Undercounted 2019 Brief: Struggling to Make Ends Meet in Pennsylvania, available at: http://www.selfsufficiencystandard.org/Pennsylvania.

[15] See PathWays PA, Overlooked and Undercounted, How the Great Recession Impacted Household Self-Sufficiency in Pennsylvania, http://www.selfsufficiencystandard.org/sites/default/files/selfsuff/docs/PA2012.pdf.

[16] Average Self Sufficiency Standard of all 26 Pennsylvania counties served by CPA for four-person households that include two adults, one infant, and one preschooler. See 2021 Pennsylvania Sufficiency Standard, available at: http://www.selfsufficiencystandard.org/Pennsylvania;.

[17] CAUSE-PA to CPA I-4, I-5.

heating, cooking, and hot water, will result in increased unaffordability for low and moderate income households, and will likely result in a corresponding increased rate of uncollectible expenses and service termination.

Q: How would Columbia's proposed rate increase impact low income households?

A: Low income households are struggling now more than ever. Even in relatively good economic times, low income families struggle to make ends meet each month, and are often forced to choose between critical necessities. Any increase in costs for essential services, like natural gas, can have a severe impact on low income households – forcing many to make impossible trade-offs between paying for shelter, food, utilities, or other basic needs.

Not counting the cumulative effect of Columbia's other recent rate increases, the proposed average monthly increase of $14.60[18] - or $175.20 annually - is a substantial increase in basic living expenses even for many moderate income households. The average annual income for the Company's confirmed low income customers is $17,958.[19] For a household at this income level, the $175.20 increase represents an additional 1% of their gross annual household income and Columbia's proposed $1,384.44 annual bill would account for approximately 7.7% of this household's annual income. For these low income households who already struggle to afford their monthly bills, the effects of the proposed increase may profoundly impact their ability to connect, maintain, and afford natural gas service.

To further contextualize the impact of the proposed increase on low income households, it is helpful to look at the relative energy burden (the percentage of income a household pays for

[18] Rate Filing Cover Letter at 2, See also Ex. 111, Sched. 6 at 1.
[19] CAUSE-PA to CPA I-4.

energy costs) of low income households. To be affordable, a household's total housing costs – *including utility costs* - should account for no more than 30% of the household's total income.[20] But across Pennsylvania, households with income at or below 150% FPL spend as much as 29% of their income on *energy costs alone*.[21] In comparison, BCS estimates that the energy burden of Pennsylvania's residential customers as a whole (exclusive of those enrolled in a Customer Assistance Program (CAP)) is roughly 4%.[22]

Even with bill assistance through CAP, many of Columbia's low income consumers still face disproportionately high energy burdens – particularly the poorest customers with income at or below 50% FPL and those enrolled in the percentage of income payment plan.[23] Thus far in 2021, the average portion of energy burden attributable to Columbia's CAP customers' gas bills range between 2.89% to 8.0%, while the burden for customers at or below 50% FPL ranged from 5.1% to 7.56%.[24] For CAP customers who receive the percentage of income payment (PIP) rate, the natural gas burdens range from 7.56% to 8.0%, while the burden for those with the average bill payment plan rate ranges from 2.89% to 5.1%.[25] These are, of course, average burdens for CAP participants. On an individual basis, many CAP customers likely exceed these high averages. It is also important to consider that these energy burdens represent the percentage of income

[20] US Dep't of Housing & Urban Development, Affordable Housing, available at https://www.hud.gov/program_offices/comm_planning/affordablehousing.

[21] See Fisher, Sheehan & Colton, The Home Energy Affordability Gap: Pennsylvania (April 2021), http://www.homeenergyaffordabilitygap.com/03a_affordabilityData.html.

[22] Energy Affordability for Low income Customers, Docket No. M-2017-2587711, Order, at 8 (Jan. 17, 2019); see also Diana Hernandez, Energy Insecurity: A Framework for Understanding Energy, the Built Environment, and Health Among Vulnerable Populations in the Context of Climate Change, 103(4) Am. J. Pub. Health (2013), *available at* http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3673265/#bib20.

[23] CAUSE-PA to CPA I-6.

[24] Id.

[25] Id.

dedicated natural gas service only – ***not including the additional cost of electricity, water, wastewater, and telecommunication services.***

Notably, CAP only reaches a small portion of the eligible population. As of May 2021, only 24,332 of Columbia's residential customers were enrolled in CAP[26] – this is approximately 35% of Columbia's confirmed low income customers[27] or 25% of estimated low income customers.[28] Therefore, between 65-75% of Columbia's low income customers will bear the full impact of the proposed rate increase.

The overwhelming energy burden on low income households makes it difficult to pay for other basic necessities such as housing, food, and medicine; threatens stable and continued employment and education; has substantial and long-term impacts on mental and physical health;[29] creates serious risks to the household and the larger community; and negatively impacts the greater economy.[30] According to the US Energy Information Administration, roughly 1 in 5 households in 2015 – when the economy was experiencing a relatively prosperous economic period – reported that they reduce or forego other critical necessities like food and medicine to afford their home energy costs, and more than 1 in 10 reported keeping their home at an unsafe or unhealthy temperature.[31] Even with financial assistance, low income households are still unable to afford the

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[26] CAUSE-PA to CPA I-7.

[27] See CAUSE-PA to CPA I-3 (CPA reports 69,554 confirmed low income customers).

[28] See CAUSE-PA to CPA I-2 (CPA reports 96,648 estimated low income).

[29] Diana Hernández, Yumiko Aratani, Yang Jiang, Energy Insecurity among Families with Children, National Center for Children in Poverty, January 2014, at 3, available at: http://www.nccp.org/publications/pub_1086.html ;

[30] US EIA, Residential Energy Consumption Survey (2015), https://www.eia.gov/consumption/residential/reports/2015/energybills/; see also NEADA, 2018 National Energy Assistance Survey, at 17, 20 (Dec. 2018), http://neada.org/wp-content/uploads/2015/03/liheapsurvey2018.pdf (hereinafter NEADA Survey).

[31] US EIA, Residential Energy Consumption Survey (2015), https://www.eia.gov/consumption/residential/reports/2015/energybills/.

cost of energy: According to a survey conducted by the National Energy Assistance Directors' Association, 72% of LIHEAP recipients reported that they forego other necessities to afford energy, and 26% reported keeping their home at unsafe or unhealthy temperatures.[32] Indeed, as recent research and data has continually showed, vulnerable low income families simply cannot afford the cost of energy services.

Ultimately, an increase in rates for natural gas service such as the increase proposed here will compound existing unaffordability for vulnerable households, and is likely to result in a corresponding increase in uncollectible expenses and, in turn, involuntary payment-related terminations. These impacts can and do have a deep and lasting impact on the health and wellbeing of those in the household and the welfare of the community as a whole.[33] As such, no rate increase should be permitted without first addressing the current affordability gap for Columbia's low income customers.

Q: Is there other evidence that Columbia's low income customers already struggle to afford and maintain natural gas service – even before any rate increase is approved?

A: Yes. There are strong indicators that service is already unaffordable. A disproportionate percentage of Columbia's payment troubled residential customers are low income. Despite the fact that confirmed low income customers only account for approximately 24% of Columbia's

[32] NEADA Survey at 17, 20.

[33] See Id. When a family is unable to use their primary heating system, they often resort to dangerous, high usage, and high cost alternative heating methods such as electric space-heaters, electric stoves, and/or portable generators, which increases the risk of carbon monoxide poisoning and house fires – placing themselves and the greater community at risk of harm. See Nat'l Fire Protection Ass'n, Fire Analysis & Research Division, Home Fires Involving Heating Equipment, at 1 (Dec. 2018) (finding that space heaters cause 44% of all home heating related fires, and 86% of deaths caused by home heating related fires).

residential customers,[34] they account for 39.71% of residential customers in arrears (not including those enrolled in CAP).[35] As of April 2021, 15.46% of confirmed low income customers were in debt to Columbia, compared to just 6.54% of general residential customers.[36]

Further, despite the fact that confirmed low income customers only represent approximately 24% of residential ratepayers, they represent 40% of customers in debt and carry approximately 66% of the dollars owed.[37] These indicators demonstrate that Columbia's low income consumers already struggle to pay for natural gas service, and will likely experience increased payment trouble if the proposed rate increase is approved without taking necessary measures to mitigate the impact of the increase on low income households.

Q: Do you believe that there is an increased threat of termination for low income customers as a result of the proposed rate increase?

A: Yes. Low income customers already have a markedly higher rate of termination compared to average residential customers. Columbia did not perform residential terminations in 2020; however, in 2019 Columbia's residential termination rate was 2.7%, compared to 8.98% for confirmed low income customers.[38] Thus, prior to the COVID-19 termination moratorium, confirmed low income customers were more than three times as likely to have service terminated than general residential customers. This disparity in termination rates is likely to continue – and may become even more pronounced – now that the emergency moratorium on utility terminations

[34] See CAUSE-PA to CPA I-1, I-2.
[35] CAUSE-PA to CPA I-8.
[36] CAUSE-PA to CPA I-10, Attach.
[37] Id. (10,751 out of 26,751 customers in debt were confirmed low income, accounting for $13,860,790 out of $28,964,087 in residential debt.).
[38] CAUSE-PA to CPA I-11, I-12.

has been lifted. Evidence further suggests that once disconnected, low income customers are often unable to reconnect service, and may go for extensive periods of time before restoration. In 2019, Columbia terminated 6,067 confirmed low income customers, but reconnected just 3,134.[39]

Q: How does the involuntary termination of natural gas service impact a household?

A: Loss of natural gas service can and does have a deep and lasting impact on the health and wellbeing of the entire household – as well as the community as a whole. When a family is unable to use a primary heating system, they often resort to dangerous, high usage / high cost heating methods – such as electric space-heaters, electric stoves, and/or portable generators – which increases the risk of carbon monoxide poisoning and house fires.[40] The Commission has documented this in its annual Cold Weather Survey.[41] In 2019, Columbia reported that 811 households in its service territory were without a central heating source in the winter months, and 282 households were using a potentially unsafe alternative heating source.[42] From 2015-2019, Columbia reported an annual average of 933 households without heat in winter, and an annual average of 283 households were using a potentially unsafe heating source.[43] Last winter, during

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[39] CAUSE-PA to CPA I-15.

[40] "Space heaters accounted for 33% of 2007-2011 reported home heating fires, 81% of home heating fire civilian deaths, 70% of home heating fire civilian injuries, and 51% of home heating fire direct property damage." Nat'l Fire Protection Ass'n, Fire Analysis & Research Division, Home Fires Involving Heating Equipment, at ix & 33 (Oct. 2013).

[41] *Pa PUC Emergency COVID-19 Moratorium Order*, Docket M-2020-3019244.

[42] Pa. PUC, 2019 & 2020 Cold Weather Survey Results – Gas, available at: http://www.puc.state.pa.us/General/publications_reports/pdf/Cold_Weather_Results_2019.pdf. Note that the 2020 Cold Weather Survey data was impacted by the Emergency Termination Moratorium Order. Last winter, during the pandemic, Columbia knew of very few households without central heating (8) or that were using a potentially unsafe heating source (3). This is certainly a positive development, but it is unlikely to continue, given Columbia has already resumed terminations – even as many struggle to catch up with substantial debts accrued the pandemic.

[43] Pa. PUC, 2019 & 2020 Cold Weather Survey Results – Gas, available at: http://www.puc.state.pa.us/General/publications_reports/pdf/Cold_Weather_Results_2019.pdf. Note that the 2020 Cold Weather Survey data was impacted by the Emergency Termination Moratorium Order.

the pandemic, Columbia knew of very few households without central heating (8) or that were using a potentially unsafe heating source (3). This is certainly a positive development, but it is unlikely to continue, given Columbia has already resumed terminations – even as many low income customers struggle to catch up with substantial debts accrued the pandemic.

Additionally, loss of essential utility service is a common catalyst to homelessness,[44] which ultimately causes communities to expend an even greater level of resources to adequately address homelessness and protect the safety of its community members.

Q: Are customers who are enrolled in the Columbia's Customer Assistance Program (CAP) protected from the financial impact of the rate increase?

A: That answer depends on the type of CAP rate the customer receives and, for some, when they are assigned that rate. Columbia offers four CAP rates:[45]

1) **Percentage of income** - which is calculated based on a fixed percentage of the customer's income;
2) **Average of payments** - which is based on the average of payments made by the customer in the last 12 months prior to joining CAP;
3) **Flat rate** - which is set at 50% of budget billing; and
4) **Minimum payment** - which is set at $25.

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[44] See Joint State Government Commission, General Assembly of the Commonwealth of Pennsylvania, Homelessness in Pennsylvania: Causes, Impacts, and Solutions: A Task Force and Advisory Committee Report (2016), http://jsg.legis.state.pa.us/resources/documents/ftp/documents/HR550%201%20page%20summary%204-6-2016.pdf.

[45] Currently, CAP customers with income between 0-110% FPL are billed at 7% of the household's monthly income; those with income between 101-150% FPL are billed at 9% of the household's monthly income; and those with income between 101-150% FPL are billed at 9% of the household's monthly income. See Columbia Gas of PA, Inc., Universal Service and Energy Conservation Plan (USECP), Docket No. M-2018-2645401, at 23 (revised Nov. 25, 2019) (hereinafter 2019-2023 USECP).

As of May 2021, a majority – 61.1% – of Columbia's CAP customers are billed at the 50% of budget payment option and will be charged half (50%) of any approved increase after their next budget payment re-evaluation.[46] Only the remaining 38.9% of Columbia's current CAP customers (those not billed at the percentage of bill option) would be insulated from the financial impact of a rate increase.[47] Thus, a majority of CAP customers would be impacted by the proposed increase.

Q: Are any other CAP customer groups likely to experience higher costs because of the rate increase?

A: Yes. The proposed rate increase will impact the CAP bills of customers who receive the average payment CAP rate *after* the rate increase takes effect. The average payment plan charges CAP customers the average of payments made for the last 12 months prior to joining CAP.[48] After the rate increase takes effect, those applying for CAP will likely have made higher payments toward their increased bill over the twelve months prior to enrolling. Thus, their historical averages will be higher, as will their assessed CAP payment.

Q: Are all low income customers enrolled in CAP?

A: No. Very few of Columbia's low income customers are enrolled in CAP. As of May 2021, only 24,332 Columbia customers were enrolled in CAP.[49] This represents just 35% of Columbia's confirmed low income customers[50] *– or just 25% of its total estimated low income customers*.[51]

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[46] CAUSE-PA to CPA I-16, Attach.

[47] Id.

[48] 2019-2023 USECP at 23.

[49] CAUSE-PA to CPA I-7.

[50] CAUSE-PA to CPA I-3 (Columbia reports 69,554 confirmed low income customers).

[51] CAUSE-PA to CPA I-2 (Columbia reports 96,648 estimated low income customers).

In other words, between 65-75% of Columbia's low income customers are not enrolled in CAP, and will experience the full, unmitigated financial impact of the proposed rate increase.

The PUC monitors implementation of the Commission's statute, regulations, and CAP Policy Statement by NGDCs serving more than 100,000 customers. These rules require the public utilities to report the number of customers enrolled in CAP. The Commission uses the number of participants enrolled in CAP at the end of the program year to quantify participation. Columbia's CAP participation rate has shown no measurable improvement in the last decade. Table 1 shows the CAP enrollment rate for Columbia compared with the NGDC average in the last 10 Universal Service Reports:

TABLE 1: CAP Participation Rate[52]

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Columbia	36%	34%	33%	30%	30%	30%	31%	29.9%	32.8%	34.9%	33.6%
NGDC Avg.	40%	41%	40%	37%	36%	37%	35%	34%	34%	45%	34%

As of May 2021, Columbia's CAP participation rate stood at 35% - which was still lower than the CAP enrollment rate in 2009.[53] I believe that continuing to improve CAP participation will help the Company reduce the disproportionate number of payment troubled low income

[52] The CAP enrollment rate is the total of CAP customers as of December 31 of the given year, divided by the number of confirmed low income customers. CAP enrollment rates were collected from the Commission's Universal Service Programs & Collections Performance Reports (hereinafter Universal Service Reports). The last publicly available CAP enrollment data was released in December 2019 for the 2018 calendar year.

See 2019 Universal Service Report at 51, 2018 Universal Service Report at 52; 2017 Universal Service Report at 51; 2016 Universal Service Report at 50; 2015 Universal Service Report at 42; 2014 Universal Service Report at 42; 2013 Universal Service Report at 37; 2011 Universal Service Report at 40; 2009 Universal Service Report at 39; 2008 Universal Service Report at 38. Note that percentages were rounded to the nearest whole number.

[53] CAUSE-PA to CPA I-3, I-7.

customers, as well as the substantial amount of debt that is carried by low income customers. Regardless of whether any rate increase is ultimately approved, Columbia must be required to measurably improve its CAP enrollment rates to reach *all households* in need of assistance to access and maintain safe and affordable natural gas services. As an incremental step, Columbia should develop a plan to enroll at least 50% of its confirmed low income customers in CAP within the next five years. This is especially true if the Company's proposed rate increase is approved, as even more households will likely be unable to keep up with increasing rates.

Q: In addition to improved CAP enrollment, are there other steps Columbia can take to help ensure that low income customers are better able to afford natural gas service and, thus, are more appropriately shielded from the financial impact of a rate increase?

A: Yes. In addition to improving CAP enrollment rates, I believe the single most important step the Company could take to address current unaffordability and mitigate the impact of a rate case would be to reduce its percentage of income CAP rate. As I explained earlier, Columbia's CAP rates require participants to pay a substantial percentage of their income for natural gas service – especially for those receiving the PIP CAP rate.[54] These disproportionate energy burdens make it more difficult to afford both gas service and other basic necessities, and can have negative effects on employment, education, and mental and physical health. Again, this can lead to serious risks to the household and the larger community and negatively impacts the whole economy.

CPA's current CAP rates are neither just or reasonable, and have proven inadequate to ensure that low income consumers can reasonably afford to maintain service to their home.

[54] CAUSE-PA to CPA I-10 (Percentage of Income Payment energy burdens ranging 7.64-8.02%, versus other CAP options ranging 2.92-5.34%).

Columbia currently charges customers enrolled in the PIP payment option 7% of monthly income for customers at or below 110% FPL and 9% for customers between 110 to 150% FPL.[55] The Commission recently adopted a revised CAP Policy Statement, which contains its newly adopted maximum affordable energy burden standards, which are lower than the rates charged by Columbia.[56] The Commission has concluded that, to be considered affordable, CAP rates for natural gas service should not exceed 4% of household income for customers with income at or below 50% FPL and 6% of household income for customers with income between 51-150% FPL.[57] I recommend that Columbia follow the Commission's guidelines and adopt these more appropriate reduced energy burden standards for its PIP CAP rate option.

Q: What is the projected residential bill impact of your recommendation to reduce applicable CAP energy burdens for Columbia's percentage of income payment plan customers?

A: Columbia projects that adopting the revised energy burdens in the CAP Policy Statement would increase its annual CAP costs by $1,172,147.[58] Columbia projects its number of residential customers will increase from 405,078 to 411,414 between 2021 and 2023.[59] Assuming Columbia continues to recover the cost of CAP solely from residential customers, the monthly increase in residential bills as a result of adopting the Commission's maximum CAP energy burden standards would be approximately *$0.24 per customer per month*. Table 2 shows the projected increased costs to residential customers from 2021 to 2023:

[55] Columbia USECP at 23.
[56] Final CAP Policy Statement and Order at 4.
[57] 52 Pa. Code § 69.265(2)(i)(B); see also Final CAP Policy Statement and Order at 4.
[58] See CAUSE-PA to CPA I-17.
[59] Id.

Table 2: CAP Cost Projections

	2021	2022	2023
Increased Annual CAP costs	$1,172,147	$1,172,147	$1,172,147
Number of Residential Customers	405,078	408,259	411,414
Annual Cost Per Customer	$2.89	$2.87	$2.84
Monthly Cost Per Customer	$0.24	$0.24	$0.24

I believe that $0.24 a month is a small price to pay to mitigate the significant negative consequences of energy poverty, and for the host of far-ranging individual and societal benefits associated with improved energy affordability.

Q: Does LIHEAP mitigate the harm of the proposed rate increase on low income households?

A: No. As a preliminary matter, relative to estimated need, there are few Columbia customers that receive LIHEAP assistance. In the 2020-2021 LIHEAP season, the number of Columbia customers receiving LIHEAP cash grants was 13,671, which is approximately 19.7% of Columbia's confirmed low income or about 14.1% of Columbia's estimated low income customers.[60]

LIHEAP is a critically important program and provides life-sustaining assistance to those in need, but the program is intended to provide supplemental energy assistance. LIHEAP benefits are not adjusted to mitigate the financial impact of a rate increase. As proposed, Columbia's residential rates would increase by an *average* of $175.20 per year.[61] In comparison, the average cash grant amount for natural gas customers in the 2020-2021 LIHEAP program year was $274.[62]

[60] CAUSE-PA to CPA I-5; see also CAUSE-PA to CPA I-2 (96,648 estimated low income customers).

[61] Rate Filing Cover Letter.

[62] Appendix C, Pa. Dep't of Human Services, Energy Assistance Summary (EASUM), at 68 of 136 (report generated June 12, 2021).

In other words, the proposed rate increase will consume **more than half** – approximately 64% – of the average LIHEAP cash grant, eclipsing a significant portion of the benefit received by low income customers through the LIHEAP program.

Q: Will Columbia's Low Income Usage Reduction Program (LIURP) program sufficiently mitigate the financial impact of the proposed rate increase on low income households?

A: Columbia's LIURP program can help mitigate the impact of the proposed rate increase on low income high-use households. However, many high usage, low income households are unable to access LIURP services for a number of reasons, including health and safety issues in the home. This means that some of the most vulnerable low income consumers with already high energy costs due to poor and inefficient housing stock will face unmitigated financial hardship as a result of Columbia's proposed rate increase. As a condition to any approved rate increase, and to better protect those most vulnerable to the substantial proposed rate increase, I recommend that Columbia to extend its health and safety pilot program for an additional term, and increase the budget by $600,000 annually.

Columbia's Health and Safety Pilot serves high-usage CAP customer homes unable to receive weatherization services without first correcting existing health and safety issues in the home.[63] The pilot is open to homeowners enrolled in CAP and have high usage and high CAP credits, and who are unable to obtain LIURP weatherization due to health and safety issues, such

[63] Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2019-2021, Order, Docket No. M-2018-2645401, P-2019-3007876, at 27-28 (order entered Aug. 8, 2019) (hereinafter "Aug. 2019 USECP Order").

as knob and tube wiring, presence of moisture, mold, or mildew.[64] Through the pilot, Columbia will remediate the health and safety issues if such action will result in comprehensive measure installation and expected usage reductions greater than 18%.[65] The program began in January 2020 and will run through December 2022.[66] Columbia's budget for the program is $200,000 per year, with which it projects serving 30 homes per year.

When dangerous issues are present in a home, it is to everyone's benefit that such matters are addressed timely before further damage or additional adverse conditions evolve.[67] Homes that cannot be weatherized because of health and safety concerns are dangerous to live in and dangerous to communities.[68] By removing barriers to LIURP participation due to health and safety issues, Columbia would improve the ability of low income households with health and safety concerns to access LIURP services, reduce uncontrollably high household energy costs exacerbated by poor housing conditions, and help improve the lives of Columbia's customers and the communities in which they live and work. Columbia proposed the Health and Safety Pilot Program after conducting an evaluation of the costs of LIURP jobs that are deferred due to health and safety issues to determine whether it was possible to increase the Health and Safety budget at a job level while still maintaining cost effectiveness for the overall program.[69] The evaluator

[64] 2019-2023 USECP at 19.

[65] Id.

[66] 2019-2023 USECP at 17.

[67] Aug 2019 USECP Order at 29.

[68] See, e.g., Pamela M. Blumenthal & John R. McGinty, Urban Institute, Housing Policy Levers to Promote Economic Mobility, (Oct. 2015) ("Housing-based triggers cause up to 40 percent of children's asthma episodes. According to one study, moving an asthmatic child from poor-quality housing into a green, healthy home reduces asthma-related doctor visits by 66 percent, keeping the child in school and the parent at work. Poor-quality housing also correlates with child and adolescent emotional and behavioral problems, adolescent academic skills, and early developmental delays and physical health.") (internal citation omitted).

[69] See 2019-2023 USECP, Append. A.

determined that 47% of Columbia's LIURP jobs presented health and safety issues and that these issues prevented 120 households from receiving needed weatherization.[70] The evaluator recommended that, depending on the job characteristics, the Company could spend a significant amount of funds on remediating health and safety issues and still achieve cost-effective savings, given the high level of opportunities for savings found in these homes.[71] The evaluator's report explained that this approach would yield high energy savings, reduce costs for ratepayers who are contributing to the costs of CAP, and improve the ability of CAP customers to afford their full bill when/if they exit the program.[72]

As stated above, as currently designed and budgeted, the pilot is designed to serve approximately 30 households per year. However, as reflected in the evaluation, the need for this service is far greater. It is vitally important – especially in light of the proposed rate increase – that otherwise eligible households be able to access usage reduction and energy efficiency services through LIURP to help reduce their bill. LIURP is a critical universal service program that, in tandem with CAP, improves bill affordability and reduces arrearages and termination rates over the long term.[73] LIURP participants achieve substantial bill savings and energy usage reduction, which is critical for low income households.[74] Importantly in this context, LIURP can help mitigate the impact of the proposed increase on high-use, low income customers. However, many customers are prevented from obtaining this valuable service due to health and safety issues in their home that they cannot afford to address.

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[70] Id. at 38.

[71] Id.

[72] Id.

[73] 52 Pa. Code § 58.1; 2020-2025 USECP at 25.

[74] 2018 Universal Service Report at 50-51.

Renewing the Health and Safety Pilot and increasing the budget will allow the Company to serve a greater number of households, thereby protecting its customers and the community from the dangers of these household health and safety issues – while at the same time improving the availability of usage reduction services for high usage customers who would not otherwise be eligible for LIURP services. This will, in turn, help Columbia's uniquely vulnerable customers mitigate the impact of the rate increase by reducing their bills over the long term – and will have a reciprocal impact on CAP costs by helping to control high usage. Thus, I recommend that Columbia renew the Pilot, increase the budget by $600,000 per year. At this level of funding, Columbia could serve an additional 90 households per year that would otherwise be deferred from critical usage reduction and energy efficiency services as a result of health and safety issues in the home. This would provide an adequate level of funding to more fully serve the need identified in the report based on Columbia's 2017 annual health and safety deferral figures.[75] Columbia should also be required to submit both an interim and final report on the pilot outcomes, which can be utilized in its next LIURP evaluation to determine the effectiveness of the program.

II. <u>RATE DESIGN</u>

Q: Please describe Columbia's residential rate design proposal.

A: Columbia seeks to increase its fixed monthly residential customer charge from $16.75 to $19.33, an increase of $2.58 or 15.4%.[76]

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[75] 2019-2023 USECP, Append. A at 38.

[76] CPA St. 11 at 22.

Q: How would Columbia's proposed rate design impact low income households?

A: This level of increase to the fixed charge will undermine the ability for consumers to control costs through energy efficiency, conservation, and consumption reduction, which is particularly problematic for low income customers. These customers already struggle to pay for natural gas service, and rely on the ability to offset high bills through careful conservation and usage reduction. Regardless of the level of household usage, any increase to the fixed charge prevents customers from exercising the ability to use conservation measures to mitigate that portion of the rate increase.

Q: Would Columbia's proposed increase to the fixed charge affect the Company's LIURP program?

A: Yes. Columbia's proposal undermines the explicit goals of the Low income Usage Reduction Program (LIURP). The Commission's LIURP regulations explicitly provide that the program is intended to help low income customers to reduce their *bills* and, in turn, to "decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs."[77] By reducing the amount of bill savings that can be obtained through LIURP participation, the proposed increase to the fixed charge threatens the continued effectiveness of ratepayer investments intended to reduce energy consumption, delinquencies, collections, and uncollectible costs. The explicit goals of the program will be more difficult to achieve as the fixed portion of the bill is increased.

[77] 52 Pa. Code § 58.1 ("The programs are intended to assist low income customers conserve energy and reduce residential energy bills. The reduction in energy bills should decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs.").

LIURP is effective at achieving these goals and producing meaningful average bill savings. In 2016, the last year for which industry wide data is available, LIURP saved participants an average of $324 per year – or $27 per month.[78] In 2019, homes served by Columbia's LIURP saved an average of 20.67%.[79] The ability to save money through energy efficiency is tied directly to a bill structure that bases costs on throughput. But as more residential customer costs are shifted to the fixed charge, the achievable bill savings – and the corresponding impact on bill payment behavior – will erode.

This is even more critical for households with income above 150% FPL but less than 200% FPL who are ineligible for CAP or LIHEAP, but are eligible for energy efficiency and conservation services through LIURP or the federal Weatherization Assistance Program (WAP) – both of which have income guidelines of up to 200% FPL. It is critical that these households retain the ability to reduce their monthly energy costs through adoption of comprehensive energy efficiency and conservation programming.

Given low income households are disproportionately payment troubled, and often lack the ability to reasonably control usage due to poor housing stock and older, less efficient appliances,[80] it is critical that they continue to have access to effective conservation tools capable of producing meaningful and lasting bill reductions. Of course, in addition to undermining the effectiveness of millions of dollars in LIURP investments, Columbia's high fixed charge proposal will also

[78] 2019 Universal Service Report at 49 (Estimated annual bill reductions are based on the average of the public utility results from each category of LIURP jobs completed in the program year, evaluated in following year, and reported in the year after that.).

[79] CAUSE-PA to CPA appe19.

[80] See ACEEE, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low income and Underserved Communities (April 2016), https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf.

undermine the millions of ratepayer dollars that the Company is authorized to invest in energy efficiency through its voluntary Energy Efficiency and Conservation Program Plan.

Q: Do you have any recommendations that could help mitigate the effect of the proposed rate design on low income households?

A: Yes. Columbia's fixed monthly customer charges should not be increased. To the extent any increase in the Company's residential distribution rate is approved, it should be applied to the volumetric charge. This would protect the ability of low income households to lower their utility costs by reducing consumption and would preserve the effectiveness of the LIURP program at reducing customer bills and improving payment behavior.

Q: Are there any other aspects of Columbia's proposed rate structure that you would like to address?

A: Yes. Columbia has proposed a Revenue Normalization Adjustment Rider (Rider RNA), which is designed to "break the link" between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers.[81] The RNA proposed by Columbia provides benchmark distribution revenue levels regardless of changes in customers' actual usage levels and would adjust actual non-gas distribution revenue for the non-CAP residential customer class.[82] Essentially, Rider RNA would allow Columbia to collect its revenue on a per customer basis – rather than on a usage basis.[83]

[81] CPA St. 11 at 27.

[82] Id.

[83] Id.

Q: Do you support Columbia's Rider RNA proposal?

A: No. I believe that Columbia's Rider RNA should be rejected. For the same reasons discussed at length above with regard to the fixed charge, I oppose implementation of Columbia's Rider RNA. In short, and without unnecessarily repeating my previous arguments, recovering revenue on a per customer basis, rather than a usage basis, strips low income households of the ability to control their bill through usage reduction and conservation efforts, and undermines the effectiveness of the Low income Usage Reduction Program and other weatherization and energy efficiency programs at reducing low income customer bills. As such, the proposed Rider RNA will potentially have a disproportionately negative impact on low income consumers. While it may appear to the consumer that they have successfully reduced their energy costs over the short term, the practical effect of the Rider RNA will be to charge the consumer the difference on the back end – six months to a year later.

While Columbia has proposed to exclude CAP customers from Rider RNA,[84] this does not remediate my concern that Rider RNA will negatively impact the many non-CAP low income consumers and will undermine the effectiveness of LIURP at reducing customer bills. As I have previously explained, roughly 65-75% of Columbia's confirmed low income customers are not enrolled in CAP.[85] These consumers will not be shielded from the impact of Rider RNA, and – as addressed above, given current enrollment levels - it is not reasonable to conclude that these consumers will simply be able to enroll in CAP to avoid the Rider RNA.

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[84] Id. at 39.

[85] See CAUSE-PA to CPA I-2, I-3, I-7.

Q: If Rider RNA were approved, do you have any recommendations to mitigate the impact on low income customers?

A: Yes. If Rider RNA is ultimately approved, Columbia should be required to exempt all confirmed low income customers from the charge.

III. LANGUAGE ACCESS

Q: How will Columbia's proposed rate increase impact limited English proficient consumers in its service territory?

A: On average, limited English proficient individuals earn lower wages than their English proficient counterparts.[86] Thus, any rate increase would have the tendency to disproportionately impact immigrant communities in which there are large numbers of limited English proficient individuals.[87]

Q: How does Columbia assess the needs of its LEP population?

A: In order to determine needs for areas with limited English proficient Columbia customers, the company uses the American Community Survey conducted by the Census Bureau.[88] None of the areas served by Columbia have a population of over 5%; however, Columbia identified six counties where the percentage of limited English proficient population is over 2.0% percent.[89]

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[86] "In 2013, about 25% of LEP individuals lived in households with an annual income below the official federal poverty line – nearly twice as high as the share of English-proficient persons (14 percent)." Jie Zong & Jeanne Batalova, *The Limited English Proficient Population in the United States*, Migration Policy Institute Journal (July 8, 2015), http://www.migrationpolicy.org/article/limited-english-proficient-population-united-states.

[87] Id. ("In 2013, about 50% of immigrants (20.4 million) were LEP, compared to 2 percent of the U.S.-born population.")

[88] CAUSE-PA to CPA I-33.

[89] Id. (The counties where the percentage of limited English proficient population is over 2.0% percent are Adams County, Allegheny County, Centre County, Franklin County, Indiana County, and York County.).

Q: What are Columbia's language access procedures?

A: Columbia's language access procedures involve multiple channels of translation to ensure that customers receive information in their language.[90] Columbia's website offers a Google Translate feature, which allows visitors to the site to translate content to Spanish, Portuguese, Korean, Japanese, German, French, and Simplified Chinese.[91] The Company's customer care center and field employees have access to Columbia's third party interpreter, Language Line, which offers translation into 240 languages.[92]

Q: Do you have any recommendations about how Columbia can improve its language access procedures?

A: Yes. I believe that Columbia should develop multi-lingual universal service outreach materials to distribute as bill inserts and online that inform customers that these translation services are available. Both the bill inserts and the online communications should list all of the languages available for translation and the online communication should link to the translated website feature. This will help Columbia utilize the tools it has implemented for customer point of contacts to bolster universal service outreach.

Also, Columbia should closely monitor translation requests to identify pockets of limited English proficient customers so that it can tailor its communications with those communities. Columbia indicates that it tracks the number of phone translation requests; however, the Company does not track which translation requests are made in Pennsylvania.[93]

[90] CAUSE-PA to CPA I-32
[91] Id.
[92] Id.
[93] CAUSE-PA to CPA I-22.

I recommend that Columbia begin tracking the number of translation requests by language requested and the county of the requestor. This will help Columbia better target communications to reach specific communities in their primary languages.

IV. SECURITY DEPOSITS

Q: Please summarize your concerns regarding Columbia's security deposit retention practices, mentioned at the outset of your testimony.

A: Columbia's tariff indicates that "CAP customers will not be charged security deposits," and provides for waiver of security deposits for "customers entering into the CAP."[94] However, the Public Utility Code[95] and Commission regulations[96] plainly impose a prohibition on security deposits for all households confirmed to be income-eligible for CAP. This does not just apply to customers who enroll in the program, but all customers who are eligible for the program based on their household income – regardless of whether the household actually enrolls in the program. Columbia's tariff provides that customers can be refused access to natural gas service for failure to provide a security deposit.[97] This can prove an insurmountable obstacle for low income customers who already struggle just to afford service. I recommend that Columbia amend its tariff language to indicate that all customers confirmed to be income eligible for CAP will not be charged a security deposit, regardless of whether the household subsequently enrolls in CAP.

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[94] Tariff at 140.

[95] 66 Pa. C.S. § 1404(a.1) ("**Cash deposit prohibition**.--Notwithstanding subsection (a), no public utility may require a customer or applicant that is confirmed to be eligible for a customer assistance program to provide a cash deposit.").

[96] 52 Pa. Code § 56.32(e):

> Notwithstanding subsection (a), **a public utility may not require a cash deposit from an applicant who is, <u>based upon household income</u>, confirmed to be eligible for a customer assistance program**. An applicant is confirmed to be eligible for a customer assistance program by the public utility if the applicant provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirements that are consistent with those of the public utility's customer assistance programs. (emphasis added).

[97] Tariff at 39.

In response to discovery, Columbia admitted that it is currently holding $239,277 in security deposits for 1,494 confirmed low income customers.[98] I recommend that all deposits being held for customers with confirmed low income be refunded to customers by no later than 30 days from of the effective date of rates in this proceeding. I further recommend that Coumbia review currently held security deposits on a monthly basis and issue a bill credit or refund for any deposit previously collected from a confirmed low income customer.

V. SUMMARY OF RECOMMENDATIONS

Q: Please summarize your recommendations.

A: As I noted from the outset of my testimony, I do not believe that Columbia's proposed rate increase should be granted unless specific and immediate measures are taken to address unaffordability of service for low income consumers. I made several recommendations throughout my testimony to address current levels of unaffordability and mitigate the financial impact of any approved rate increase on low income households, including the following:

- Reduce the Maximum Energy Burden for Percentage of Income CAP Rate Customers
- Increase the LIURP Health and Safety Pilot Program budget by $600,000 per year, and extend the program for an additional term. Columbia should submit both an interim and final report on the pilot outcomes, which can be utilized in its next LIURP evaluation to determine the effectiveness of the program
- Reject Columbia's Proposal to Increase its Fixed Residential Customer Charge
- Reject Columbia's proposed Rider RNA

[98] CAUSE-PA to CPA I-23.

- Direct Columbia to develop multi-lingual universal service outreach materials and track translation requests by language and county
- Direct Columbia to amend its tariff language to indicate that all customers confirmed income eligible for CAP will not be charged a security deposit, not just those who are able to subsequently enroll.
- Direct Columbia to refund all deposits being held for customers with confirmed low income within 30 days.
- Direct Columbia to review currently held security deposits on a monthly basis and issue a bill credit or refund for any deposit previously collected from a confirmed low income customer.

These critical reforms are necessary to ensure that Columbia's service is universally accessible to all consumers based on just and reasonable terms and conditions of service.

Q: Does this conclude your direct testimony?

A: Yes.

APPENDIX A – Harry Geller Resume

RESUME OF HARRY S. GELLER

EDUCATIONAL BACKGROUND:

Harpur College, State University of New York at Binghamton, B.A. 1966
Washington College of Law, American University, J.D. 1969
New York University Law School, courses in Urban Affairs and Poverty Law, as part of Volunteers in Service to America (VISTA) Program 1969-1971

EMPLOYMENT:

1988 – 2015 Executive Director, Pennsylvania Utility Law Project (PULP), a project of the civil non-profit Pennsylvania Legal Aid Network. PULP is dedicated to providing technical support, information sharing, and representation to low-income individuals and organizations, assisting and advocating for the low income in utility and energy matters. Responsibilities include project oversight, case consultation, co-counseling, and participation on task forces, work groups and advisory panels, community education and training in utility and energy matters affecting the low-income.

While at PULP, served in the following capacities:

- Chairman, Low-Income Home Energy Assistance Program (LIHEAP) Advisory Committee to the Secretary, Pennsylvania Department of Human Services
- Member, Pennsylvania Public Utility Commission, Consumer Advisory Council
- Coordinator, Pennsylvania Legal Services Utility/Energy Work Groups
- Member, Weatherization Policy Advisory Committee to the Department of Community and Economic Development
- Member, PECO Universal Service Advisory Committee and LIURP Subcommittee

1974-1987 Staff Attorney, Managing Attorney and ultimately, Executive Director of Legal Services, Incorporated (LSI), a civil legal services program serving Adams, Cumberland, Franklin and Fulton Counties. Through a restructuring with other legal services programs, LSI became part of what is now known as MidPenn Legal Services and Franklin County Legal Services.

1971-1972 Staff Attorney, New York City Legal Aid Society, Criminal Court and Supreme Court Branches, New York County.

1969-1971 Volunteer in Service to America (VISTA) assigned to the New York University Law School Project on Urban Affairs and Poverty Law.

BAR ADMISSIONS

New York State
Commonwealth of Pennsylvania
United States District Court, Middle District of Pennsylvania

Cases in which Harry S. Geller has participated as a witness before the Pennsylvania Public Utility Commission since July 1, 2015

- Tenant Union Representative Network v. PECO Energy Company, C-2020-3021557
- Pennsylvania Public Utility Commission v. Philadelphia Gas Works, R-2020-3017206
- Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program for the Period of June 1, 2021 through May 31 , 2025, Docket No. P-2020-3019356.
- Petition of PECO Energy Company for Approval of Its Default Service Program for the Period from June 1, 2021 through May 31, 2025, Docket No. P-2020-3019290.
- Petition of Duquesne Light Company for Approval of Default Service Plan for the Period June 1, 2021 through May 31, 2025, Docket No. P-2020-3019522.
- Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC and Peoples Gas Company LLC for all of the Authority and Necessary Certificates of Public Convenience to Approve a Change in Control of Peoples Natural Gas Company LLC, and Peoples Gas Company LLC by way of the Purchase of all of LDC Funding LLC's Membership Interests by Aqua America, Inc., Docket Nos. A-2018-3006061, A-2018-3006062, A-2018-3006063.
- Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc. et al. Docket Nos. R-2018-3003558 et seq.
- Pennsylvania Public Utility Commission v. Duquesne Light Company, Docket No. R-2018-3000124.
- Pennsylvania Public Utility Commission v. PECO Energy Company- Electric Division, Docket No. R-2018-3000164.
- Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs for the period commencing June 1, 2019 through May 31, 2023, Docket Nos. P-2017-2637855, P-2017-2637857, P-2017-2637858; P-2017-2637866.
- Pennsylvania Public Utility Commission et al. v. Philadelphia Gas Works, Docket No. R-2017-2586783.
- PECO Energy Company's Pilot Plan for an Advance Payments Program and Petition for Temporary Waiver of Portions of the Commission's Regulations with Respect to that Plan, Docket No. P-2016-2573023.
- Petition of PECO Energy Company for Approval of a Default Service Program for the Period of June 1, 2017 through May 31, 2019, Docket No. P-2016-2534980.
- Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period of June 1, 2017 through May 31, 2021, Docket No. P-2016-2526627.
- Petition of Duquesne Light Company for Approval of a Default Service Program for the Period of June 1, 2017 through May 31, 2021, Docket No. P-2016-2543140.
- Pennsylvania Public Utility Commission et al. v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2016-2529660.
- Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs for the period commencing June 1, 2017 through May 31, 2019, Docket Nos. P-2015-2511333 , P-2015-25113351, P-2015-2511355; P-2015-2511356.
- Petition of PPL Electric Utilities Corporation for Approval of its Energy Efficiency and Conservation Plan, Docket No. M-2015-2515642.

APPENDIX B – CITED DISCOVERY RESPONSES

Interrogatories of the Coalition for Affordable Utility Service and Energy Efficiency (CAUSE-PA) directed to Columbia Gas of Pennsylvania, Inc. (CPA)

CAUSE-PA to CPA I-1

CAUSE-PA to CPA I-2

CAUSE-PA to CPA I-3

CAUSE-PA to CPA I-4

CAUSE-PA to CPA I-5

CAUSE-PA to CPA I-6

CAUSE-PA to CPA I-7

CAUSE-PA to CPA I-8

CAUSE-PA to CPA I-10

CAUSE-PA to CPA I-11

CAUSE-PA to CPA I-12

CAUSE-PA to CPA I-15

CAUSE-PA to CPA I-16

CAUSE-PA to CPA I-17

CAUSE-PA to CPA I-19

CAUSE-PA to CPA I-22

CAUSE-PA to CPA I-23

CAUSE-PA to CPA I-32

CAUSE-PA to CPA I-33

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-001:

As of the most recent available date, how many residential customers did Columbia have? Please explain how Columbia arrived at its estimated figures, and include citation and/or copies of any and all workpapers used to perform the calculation.

Response:

Columbia had 404,693 total residential customers as of April 2021, the most recent actual customer count available. The count is based on accumulation of Residential Sales and CHOICE transportation active customers as of their April meter reading date. CAUSE-PA 1-001 Attachment A is a report generated from the Revenue & Statistics backup files created after each night's billings.

R-2021-3024296 CAUSE-PA Set 1, I-001
CAUSE-PA Letter
Attachment A
Appendix B

COLUMBIA GAS OF PENNSYLVANIA, INC.
ACTUAL BILLED RESIDENTIAL SALES SUMMARY
FOR THE TWELVE MONTHS ENDED 4/2021

TOTAL COMPANY SUMMARY

MONTH	RESIDENTIAL	COMMERCIAL	OTHER	ELEC GEN	TOTAL
BILLS					
JANUARY	324154.	0.	0.	0.	324154.
FEBRUARY	325041.	0.	0.	0.	325041.
MARCH	325680.	0.	0.	0.	325680.
APRIL	326048.	0.	0.	0.	326048.
MAY	317153.	0.	0.	0.	317153.
JUNE	317326.	0.	0.	0.	317326.
JULY	317588.	0.	0.	0.	317588.
AUGUST	318125.	0.	0.	0.	318125.
SEPTEMBER	318949.	0.	0.	0.	318949.
OCTOBER	319997.	0.	0.	0.	319997.
NOVEMBER	321236.	0.	0.	0.	321236.
DECEMBER	322930.	0.	0.	0.	322930.
TOTAL	3854227.	0.	0.	0.	3854227.
DTH SALES					
JANUARY	5039471.1	0.0	0.0	0.0	5039471.1
FEBRUARY	5274679.4	0.0	0.0	0.0	5274679.4
MARCH	4243303.3	0.0	0.0	0.0	4243303.3
APRIL	2240046.1	0.0	0.0	0.0	2240046.1
MAY	1943559.8	0.0	0.0	0.0	1943559.8
JUNE	803904.6	0.0	0.0	0.0	803904.6
JULY	440857.4	0.0	0.0	0.0	440857.4
AUGUST	381290.9	0.0	0.0	0.0	381290.9
SEPTEMBER	430984.2	0.0	0.0	0.0	430984.2
OCTOBER	708536.5	0.0	0.0	0.0	708536.5
NOVEMBER	1547483.3	0.0	0.0	0.0	1547483.3
DECEMBER	3373510.7	0.0	0.0	0.0	3373510.7
TOTAL	26427627.3	0.0	0.0	0.0	26427627.3
REVENUE					
JANUARY	61176956.15	0.00	0.00	0.00	61176956.15
FEBRUARY	64458247.08	0.00	0.00	0.00	64458247.08
MARCH	58795153.74	0.00	0.00	0.00	58795153.74
APRIL	35287093.80	0.00	0.00	0.00	35287093.80
MAY	20439342.60	0.00	0.00	0.00	20439342.60
JUNE	13231305.86	0.00	0.00	0.00	13231305.86
JULY	9706212.53	0.00	0.00	0.00	9706212.53
AUGUST	9246544.08	0.00	0.00	0.00	9246544.08
SEPTEMBER	9922022.37	0.00	0.00	0.00	9922022.37
OCTOBER	13058219.79	0.00	0.00	0.00	13058219.79
NOVEMBER	23257671.12	0.00	0.00	0.00	23257671.12
DECEMBER	43526412.00	0.00	0.00	0.00	43526412.00
TOTAL	362105181.12	0.00	0.00	0.00	362105181.12

COLUMBIA GAS OF PENNSYLVANIA, INC.
ACTUAL BILLED RESIDENTIAL CHOICE TRANSPORTATION DATA SUMMARY
FOR THE TWELVE MONTHS ENDED 4/2021

TOTAL COMPANY SUMMARY

MONTH	RESIDENTIAL	COMMERCIAL	OTHER	ELEC GEN	TOTAL
BILLS					
JANUARY	79629.	0.	0.	0.	79629.
FEBRUARY	79283.	0.	0.	0.	79283.
MARCH	78952.	0.	0.	0.	78952.
APRIL	78645.	0.	0.	0.	78645.
MAY	83520.	0.	0.	0.	83520.
JUNE	83304.	0.	0.	0.	83304.
JULY	82856.	0.	0.	0.	82856.
AUGUST	82285.	0.	0.	0.	82285.
SEPTEMBER	81737.	0.	0.	0.	81737.
OCTOBER	81230.	0.	0.	0.	81230.
NOVEMBER	80781.	0.	0.	0.	80781.
DECEMBER	80078.	0.	0.	0.	80078.
TOTAL	972300.	0.	0.	0.	972300.
DTH SALES					
JANUARY	1402482.8	0.0	0.0	0.0	1402482.8
FEBRUARY	1454348.1	0.0	0.0	0.0	1454348.1
MARCH	1173067.2	0.0	0.0	0.0	1173067.2
APRIL	631725.3	0.0	0.0	0.0	631725.3
MAY	592589.7	0.0	0.0	0.0	592589.7
JUNE	238402.1	0.0	0.0	0.0	238402.1
JULY	122257.4	0.0	0.0	0.0	122257.4
AUGUST	104585.7	0.0	0.0	0.0	104585.7
SEPTEMBER	117556.5	0.0	0.0	0.0	117556.5
OCTOBER	213387.6	0.0	0.0	0.0	213387.6
NOVEMBER	459991.1	0.0	0.0	0.0	459991.1
DECEMBER	960946.4	0.0	0.0	0.0	960946.4
TOTAL	7471339.9	0.0	0.0	0.0	7471339.9
REVENUE					
JANUARY	13345072.17	0.00	0.00	0.00	13345072.17
FEBRUARY	14197375.77	0.00	0.00	0.00	14197375.77
MARCH	13478162.12	0.00	0.00	0.00	13478162.12
APRIL	8266426.87	0.00	0.00	0.00	8266426.87
MAY	4995889.74	0.00	0.00	0.00	4995889.74
JUNE	3339318.97	0.00	0.00	0.00	3339318.97
JULY	2384611.05	0.00	0.00	0.00	2384611.05
AUGUST	2259402.08	0.00	0.00	0.00	2259402.08
SEPTEMBER	2405653.76	0.00	0.00	0.00	2405653.76
OCTOBER	3127345.25	0.00	0.00	0.00	3127345.25
NOVEMBER	5441285.43	0.00	0.00	0.00	5441285.43
DECEMBER	9678315.88	0.00	0.00	0.00	9678315.88
TOTAL	82918859.09	0.00	0.00	0.00	82918859.09

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-002:

As the most recent available date, how many estimated low-income customers reside within Columbia service territory? Please explain how Columbia arrived at its estimated figures, and include citation and/or copies of any and all workpapers used to perform the estimation.

Response:

Columbia reports the estimated low income count by county as part of its Universal Service Reporting Requirements. In March, 2021, the Company reported the total estimated residential count to be 96,648. This number is calculated using census data provided by the Bureau of Consumer Services and Company customer counts. Please see Attachment A to this request for the workpapers used to perform this estimation.

County	Customer Count	Census Household	Percent Customers CPA	Census Household Low-Income	Low-Income CPA
Adams	14,334	39,345	36.43%	7,472	2,722
Allegheny	102,161	541,541	18.86%	125,605	23,695
Armstrong	865	28,137	3.07%	7,595	233
Beaver	35,761	71,167	50.25%	17,225	8,655
Bedford	12	19,882	0.06%	5,731	3
Butler	9,525	76,502	12.45%	13,749	1,712
Centre	13,372	58,201	22.98%	17,854	4,102
Clarion	3,578	16,021	22.33%	5,513	1,231
Clearfield	-	31,248	0.00%	9,821	0
Elk	31	14,020	0.22%	3,256	0
Fayette	22,416	54,837	40.88%	18,649	7,623
Franklin	4,680	60,438	7.74%	14,056	1,088
Fulton	4	5,989	0.07%	1,540	1
Greene	2,717	14,230	19.09%	3,869	739
Indiana	557	33,246	1.68%	11,504	193
Jefferson	357	18,427	1.94%	5,916	115
Lawrence	18,308	37,055	49.41%	11,007	5,438
McKean	3,170	17,147	18.49%	5,568	1,029
Mercer	29	46,340	0.06%	12,862	8
Somerset	4,761	29,644	16.06%	8,274	1,329
Venango	690	22,050	3.13%	6,442	202
Warren	2,381	17,115	13.91%	4,645	646
Washington	43,264	84,948	50.93%	18,063	9,199
Westmoreland	20,875	152,283	13.71%	32,649	4,476
York	102,244	172,421	59.30%	37,449	22,207
					96,648

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-003:

As of the most recent available date, how many of Columbia customers were/are categorized as "confirmed low income"? Please explain how Columbia arrived at its estimated figures, and include citation and/or copies of any and all workpapers used to perform the calculation. USRR

Response:

As of April, 2021, the Company categorized 69,554 customers as confirmed low income. The Company includes all customers' self- identifying as level 1 plus all customers that are participants in a Universal Service program without documented income. The Company has an auto-generated report pulled from its customer information system on a monthly basis that provides these numbers.

Please see Attachment A to this response for the relevant excerpt from the report.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
52 PA. CODE SECTION 56.231
COLUMBIA GAS OF PENNSYLVANIA, INC.
PREPARED BY :
TELEPHONE :

DI18464P
DATE 202104
DATA TYPE R
CO. I. D. 120700

LINE NO.	DESCRIPTION	NUMBER OF CUSTOMERS ACCOUNTS HEATING	NON-HEATING
	TOTAL NUMBER OF ACCOUNTS BY		
1	RESIDENTIAL	399,309	4,631
	NO FINANCIAL	285,329	3,341
	POVERTY LEVEL 1	68,364	873
	POVERTY LEVEL 2A	16,979	169
	POVERTY LEVEL 2B	10,533	103
	POVERTY LEVEL 3	6,053	39
	POVERTY LEVEL 4	12,051	106
2	RESIDENTIAL MULTI UNIT DWELLING	5,155	225
	NO FINANCIAL	4,465	207
	POVERTY LEVEL 1	309	8
	POVERTY LEVEL 2A	98	4
	POVERTY LEVEL 2B	54	1
	POVERTY LEVEL 3	43	0
	POVERTY LEVEL 4	186	5
	NUMBER OF OVERDUE ACCOUNTS BY:		
	AMOUNT OVERDUE:		
3	$25 OR LESS	796	54
	NO FINANCIAL	506	37
	POVERTY LEVEL 1	163	13
	POVERTY LEVEL 2A	46	1
	POVERTY LEVEL 2B	31	2
	POVERTY LEVEL 3	10	0
	POVERTY LEVEL 4	40	1
4	$26 TO $50	1,024	75
	NO FINANCIAL	648	56
	POVERTY LEVEL 1	187	12
	POVERTY LEVEL 2A	66	1
	POVERTY LEVEL 2B	45	1
	POVERTY LEVEL 3	25	1
	POVERTY LEVEL 4	53	4
5	$51 TO $150	6,994	112
	NO FINANCIAL	4,115	72
	POVERTY LEVEL 1	1,242	25
	POVERTY LEVEL 2A	533	4
	POVERTY LEVEL 2B	368	3
	POVERTY LEVEL 3	225	3
	POVERTY LEVEL 4	511	5
6	$151 TO $250	4,909	57
	NO FINANCIAL	2,590	32
	POVERTY LEVEL 1	947	15
	POVERTY LEVEL 2A	443	5
	POVERTY LEVEL 2B	284	1
	POVERTY LEVEL 3	204	1
	POVERTY LEVEL 4	441	3
7	$251 TO $500	4,324	49
	NO FINANCIAL	1,960	24
	POVERTY LEVEL 1	969	15
	POVERTY LEVEL 2A	418	2
	POVERTY LEVEL 2B	292	1
	POVERTY LEVEL 3	200	1
	POVERTY LEVEL 4	485	6
8	$501 TO $1,000	2,691	32
	NO FINANCIAL	1,041	11
	POVERTY LEVEL 1	760	14
	POVERTY LEVEL 2A	266	3
	POVERTY LEVEL 2B	204	4
	POVERTY LEVEL 3	108	0
	POVERTY LEVEL 4	312	0
9	OVER $1,000	2,364	12
	NO FINANCIAL	572	3
	POVERTY LEVEL 1	959	5
	POVERTY LEVEL 2A	314	3

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-004:

What is the average annual income of Columbia's currently identified confirmed low income customers?

Response:

The average annual income of Columbia's current confirmed low income customers is $17,958.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-005:

What is the average annual income of Columbia's currently enrolled CAP customers?

Response:

The average annual income of Columbia's currently enrolled CAP customers is $14,974.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-006:

For calendar years 2019, 2020, and 2021, what was the average energy burden of CAP customers (including any arrearage forgiveness co-payment or any other additional fee or charge above the average bill), disaggregated by year, income level (0-50%, 51-100%, and 101-150% of the federal poverty level), and payment plan type?

Response:

The following response does not include customers claiming zero income.

		2019	**2020**	**2021**
% of Income	**1 to 50**	7.64%	7.76%	7.56%
	51 to 100	7.40%	7.32%	7.38%
	101 to 150	8.02%	7.52%	8.00%
Avg of Payments	**1 to 50**	5.34%	5.28%	5.10%
	51 to 100	4.20%	4.16%	4.08%
	101 to 150	2.92%	3.05%	2.89%
% of Bill	**1 to 50**	5.24%	5.72%	5.31%
	51 to 100	5.02%	4.50%	4.50%
	101 to 150	3.44%	3.28%	3.28%

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-007:

For 2019, 2020, and to date in 2021, how many of Columbia's customers were/are enrolled in CAP, disaggregated by month?

Response:

Please see the chart below for the number of customers enrolled in CAP for the years 2019, 2020 and through May 2021.

Month	2019	2020	2021
January	24,788	23,809	23,305
February	21,329	20,486	23,527
March	23,306	24,188	23,838
April	23,563	23,358	24,128
May	25,576	22,411	24,332
June	21,689	23,388	
July	24,892	23,401	
August	23,342	23,301	
September	21,762	23,278	
October	23,447	23,327	
November	20,731	23,396	
December	20,350	23,542	

Columbia Gas of Pennsylvania, Inc.

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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-008:

In 2020, what percentage of Columbia's payment troubled customers were confirmed low income customers?

Response:

In December, 2020, 39.71% of all customers in arrears were categorized as confirmed low income. This does not include customers that were currently enrolled in the CAP program.

Please note: Columbia also considers as payment troubled, customers who are required to pay a security deposit and customers who are on another utilities' CAP program. The Company does not track these statistics to include in the above percentage.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-010:

For 2019, 2020, and thus far in 2021, disaggregated by month, please provide:

a. the number of residential customers in debt
b. the number of confirmed low-income customers in debt
c. the percentage of residential customers in debt
d. the percentage of confirmed low-income customers in debt
e. the dollars in debt for residential customers
f. the dollars in debt for confirmed low-income customers
g. the percent of dollars owed that are on a payment arrangement for residential customers
h. the percent of dollars owed that are on a payment arrangement for confirmed low-income customers
i. the average arrearage for residential customers
j. the average arrearage for confirmed low-income customers

Response:

Please see Attachment A to this response for the requested information.

		(a) The number of residential customers in debt	(b) The number of confirmed low-income customers in debt	(c) The percentage of residential customers in debt	(d) The percentage of confirmed low income customers in debt	(e)The dollars in debt for residential customers	(f) The dollars in debt for confirmed low-income customers	(g) The percent of dollars owed that are on a payment arrangement for residential customers	(h) The percent of dollars owed that are on a payment arrangement for confirmed low-income customers	(i) The average arrearage for residential customers	(j) The average arrearage for confirmed low-income customers
2019	January	26,170	11,807	6.53%	16.98%	$ 16,621,942	$ 8,163,421	61.29%	69.43%	$ 635.15	$ 691.41
	February	26,767	12,374	6.67%	17.74%	$ 20,879,685	$ 10,083,003	65.01%	72.35%	$ 780.05	$ 814.85
	March	26,223	11,357	6.53%	16.29%	$ 23,088,995	$ 10,808,430	71.10%	79.22%	$ 880.49	$ 951.70
	April	26,540	11,198	6.63%	16.20%	$ 21,913,644	$ 9,914,366	77.01%	85.44%	$ 825.68	$ 885.37
	May	30,878	11,835	7.73%	17.37%	$ 19,960,802	$ 8,880,108	77.88%	86.70%	$ 646.44	$ 750.33
	June	28,692	11,027	7.20%	16.28%	$ 15,510,847	$ 7,289,392	85.71%	90.84%	$ 540.60	$ 661.05
	July	31,267	11,334	7.86%	16.94%	$ 13,112,870	$ 6,181,651	83.92%	89.82%	$ 419.38	$ 545.41
	August	29,962	10,804	7.54%	16.45%	$ 10,804,292	$ 5,208,422	83.61%	90.42%	$ 360.60	$ 482.08
	Septemb	27,970	10,305	7.03%	15.71%	$ 9,115,258	$ 4,540,078	82.42%	89.63%	$ 325.89	$ 440.57
	October	26,747	10,136	6.69%	15.44%	$ 8,349,035	$ 4,414,473	80.30%	88.39%	$ 312.15	$ 435.52
	Novembe	24,302	9,655	6.04%	14.55%	$ 8,502,093	$ 4,539,214	78.95%	87.56%	$ 349.85	$ 470.14
	Decembe	23,844	10,074	5.91%	15.07%	$ 11,415,574	$ 5,865,072	72.92%	82.64%	$ 478.76	$ 582.20
2020	January	26,097	11,454	6.46%	17.10%	$ 16,880,286	$ 8,274,167	63.28%	73.22%	$ 646.83	$ 722.38
	February	26,152	13,790	6.47%	20.25%	$ 19,879,442	$ 9,773,935	66.37%	75.77%	$ 760.15	$ 708.77
	March	17,206	8,523	4.25%	12.48%	$ 15,084,881	$ 8,213,918	99.83%	99.79%	$ 876.72	$ 963.74
	April	17,594	8,727	4.35%	12.75%	$ 15,780,073	$ 8,653,668	99.98%	99.97%	$ 896.90	$ 991.60
	May	17,574	8,747	4.34%	12.76%	$ 15,606,633	$ 8,666,884	99.99%	100.00%	$ 888.05	$ 990.84
	June	17,475	8,717	4.31%	12.75%	$ 15,112,491	$ 8,546,375	99.93%	99.89%	$ 864.81	$ 980.43
	July	17,031	8,525	4.20%	12.53%	$ 14,124,057	$ 8,102,418	100.00%	100.00%	$ 829.31	$ 950.43
	August	25,392	5,401	6.26%	7.94%	$ 16,937,627	$ 9,148,578	77.96%	84.50%	$ 667.05	$ 1,693.87
	Septemb	31,798	12,513	7.83%	18.46%	$ 18,857,242	$ 9,807,967	64.00%	74.42%	$ 593.03	$ 783.82
	October	28,636	11,536	7.04%	17.01%	$ 17,590,476	$ 9,303,715	63.96%	74.85%	$ 614.28	$ 806.49
	Novembe	27,791	11,194	6.82%	16.46%	$ 17,765,104	$ 9,379,271	60.30%	71.38%	$ 639.24	$ 837.88
	Decembe	28,540	11,333	6.99%	16.55%	$ 20,752,804	$ 10,509,198	56.56%	69.62%	$ 727.15	$ 927.31
2021	January	28,216	11,501	6.91%	16.81%	$ 24,963,400	$ 12,317,336	54.17%	67.44%	$ 884.72	$ 1,070.98
	February	15,016	7,512	3.67%	10.81%	$ 18,075,336	$ 10,366,257	88.85%	94.12%	$ 1,203.74	$ 1,379.96

March	25,192	10,668	6.16%	15.33%	$	28,920,218	$	14,197,385	61.05%	73.12%	$	1,147.99	$	1,330.84
April	26,751	10,751	6.54%	15.46%	$	28,964,087	$	13,860,790	66.64%	77.40%	$	1,082.73	$	1,289.26
May	-													
June	-													
July	-													
August	-													
Septemb	-													
October	-													
Novembe	-													
Decembe	-													

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-011:

In 2019 and 2020, what was Columbia's residential termination rate?

Response:

The Company's residential termination rates were as follows:
2019 – 2.69%
2020 – 0%

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-012:

In 2019 and 2020, what was Columbia's confirmed low income termination rate?

Response:

In 2019, 8.98% of Columbia's confirmed low income customers had their service terminated. In 2020, no confirmed low income customers had their service terminated.

Columbia Gas of Pennsylvania, Inc.

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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-015:

In 2019, how many confirmed low income customers were terminated for nonpayment?

a. How many of those customers were reconnected?

b. What was the average reconnection time?

Response:

In 2019, 6,067 low income customers were terminated for non- payment.

a. 3,134 customers had service reconnected. The Company is unable to identify if each reconnection was a prior customer included in the 6,067 customers identified as being terminated in the same year.

b. The Company is unable to track the average reconnection time.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-016:

For 2019, 2020, and to date in 2021, disaggregated by month, please identify the number of Columbia CAP customers whose bills were calculated based on:

a. Average monthly bill;
b. Percentage of income (disaggregated by income tier);
c. Flat rate 50% of budget billing;
d. Minimum bill; or
e. Other (please specify).

Response:
Please see Attachment A to this response for the number of Columbia CAP customers disaggregated by month and payment plan type. Columbia's current CAP program offers a percent of income plan at 7% and 9%, the average payment in the twelve months prior to joining CAP, 50 % of the monthly budget, and the minimum bill.

		Payment Plan Option	Customers
2019	January	% of Income 7%	4653
		% of Iincome 9%	47
		Average of Payments	3332
		% of Bill	14669
		Minimum Payment	2087
	February	% of Income 7%	4016
		% of Iincome 9%	45
		Average of Payments	2841
		% of Bill	12697
		Minimum Payment	1730
	March	% of Income 7%	4395
		% of Iincome 9%	48
		Average of Payments	2996
		% of Bill	13955
		Minimum Payment	1912
	April	% of Income 7%	4409
		% of Iincome 9%	44
		Average of Payments	2906
		% of Bill	14218
		Minimum Payment	1986
	May	% of Income 7%	4777
		% of Iincome 9%	44
		Average of Payments	2999
		% of Bill	15534
		Minimum Payment	2222
	June	% of Income 7%	4038
		% of Iincome 9%	41
		Average of Payments	2505
		% of Bill	13212
		Minimum Payment	1893
	July	% of Income 7%	4647
		% of Iincome 9%	37
		Average of Payments	2771
		% of Bill	15214
		Minimum Payment	2223
	August	% of Income 7%	4382
		% of Iincome 9%	40
		Average of Payments	2529
		% of Bill	14295
		Minimum Payment	2095
	September	% of Income 7%	4097
		% of Iincome 9%	33
		Average of Payments	2309
		% of Bill	13385
		Minimum Payment	1937

	October	% of Income 7%	4371
		% of Iincome 9%	36
		Average of Payments	2727
		% of Bill	14100
2019		Minimum Payment	2017
	November	% of Income 7%	3970
		% of Iincome 9%	33
		Average of Payments	2375
		% of Bill	12384
		Minimum Payment	1792
	December	% of Income 7%	3864
		% of Iincome 9%	37
		Average of Payments	2280
		% of Bill	12263
		Minimum Payment	1745
	January	% of Income 7%	4555
		% of Iincome 9%	37
		Average of Payments	2667
		% of Bill	14576
2020		Minimum Payment	2109
	February	% of Income 7%	3911
		% of Iincome 9%	36
		Average of Payments	2255
		% of Bill	12587
		Minimum Payment	1802
	March	% of Income 7%	4608
		% of Iincome 9%	35
		Average of Payments	2602
		% of Bill	14920
		Minimum Payment	2180
	April	% of Income 7%	4429
		% of Iincome 9%	36
		Average of Payments	2477
		% of Bill	14461
		Minimum Payment	2134
	May	% of Income 7%	4242
		% of Iincome 9%	32
		Average of Payments	2350
		% of Bill	13849
		Minimum Payment	2125
	June	% of Income 7%	4456
		% of Iincome 9%	37
		Average of Payments	2148
		% of Bill	14745
		Minimum Payment	2310
	July	% of Income 7%	4468
		% of Iincome 9%	36

		Average of Payments	2148
		% of Bill	14927
		Minimum Payment	2331
	August	% of Income 7%	4353
		% of Iincome 9%	36
		Average of Payments	2071
		% of Bill	14362
		Minimum Payment	2282
	September	% of Income 7%	4339
		% of Iincome 9%	36
		Average of Payments	2067
		% of Bill	14329
		Minimum Payment	2290
	October	% of Income 7%	4671
		% of Iincome 9%	40
		Average of Payments	2200
		% of Bill	15404
		Minimum Payment	2454
	November	% of Income 7%	3889
		% of Iincome 9%	36
		Average of Payments	1837
		% of Bill	12779
		Minimum Payment	2078
	December	% of Income 7%	4322
		% of Iincome 9%	36
		Average of Payments	2053
		% of Bill	14426
		Minimum Payment	2336
2021	January	% of Income 7%	4219
		% of Iincome 9%	36
		Average of Payments	2034
		% of Bill	14108
		Minimum Payment	2295
	February	% of Income 7%	4030
		% of Iincome 9%	38
		Average of Payments	1966
		% of Bill	13436
		Minimum Payment	2233
	March	% of Income 7%	4859
		% of Iincome 9%	42
		Average of Payments	2452
		% of Bill	16239
		Minimum Payment	2745
	April	% of Income 7%	4445
		% of Iincome 9%	41
		Average of Payments	2297
		% of Bill	14791

		Minimum Payment	2553
	May	% of Income 7%	4455
		% of Iincome 9%	41
		Average of Payments	2353
		% of Bill	14874
		Minimum Payment	2609

Columbia Gas of Pennsylvania, Inc.

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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-017:

For 2021 through 2023:

a. What are Columbia's projected CAP costs, assuming Columbia maintains its currently approved enrollment terms and benefit levels?

b. What would be Columbia's projected CAP costs 2021through 2023, assuming Columbia adopted the revised energy burdens in the Commission's recently amended CAP Policy Statement as of January 1, 2021?

c. How many residential customers does Columbia project it will have?

d. How many CAP customers does Columbia project it will have?

Response:

a. The projected CAP costs for the currently approved enrollment terms and benefit levels are as follows:

	2021	2022	2023
CAP Administration and Applications	$1,300,000	$1,300,000	$1,300,000
Shortfall	$20,442,928	$20,442,928	$20,442,928
Arrearage Retirement	$975,247	$975,247	$975,247
CAP Total	**$22,718,175**	**$22,718,175**	**$22,718,175**

b. The increase in cost to reduce all customers with energy burdens higher than 4% for customers between 0 and 50% of Federal Poverty Income Guidelines (FPIG) and to 6% for customers between 51 and 150% FPIG would be reflected in the shortfall category. In 2020, the Company reported an increase of $1,019,000 annually. Based on current 2021 participation levels and current payment plan options, the increase now totals $1,172,147 annually. This assumes there is no change in any other control factors such as minimum payment or maximum CAP credits. Assuming no increase in CAP participation also, 2022 and 2023 would be roughly equal to a $1,172,147 increase to shortfall.

c. The projected residential customers, by year are:

	2021	2022	2023
Residential Customers	405,078	408,259	411,414

d. CAP projections are listed at 23,000 with the following notes:
* The projected enrollments stated in this table are estimates and should not be considered ceilings. Although Columbia is estimating enrollment levels, Columbia will continue to promote programs and enroll customers needing assistance beyond these participation levels as needed.
** Although Columbia historically has enrolled approximately 6,000 new customers annually, overall participation has remained consistent or declined due to customers moving or defaulting from the CAP program

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-019:

For the years 2018, 2019, and 2020, what was the average bill savings for LIURP participants?

Response:

The Company reports actual savings in April of each year for the year two years prior to current. Therefore, the Company does not have average bill savings for LIURP participants in 2020.

In 2018, the average savings was 18.75% with an average annual dekatherm reduction of 32.05.
In 2019, the average savings was 20.67% with an average annual dekatherm reduction of 32.80.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-022:

Does Columbia currently track the number of phone translation requests? If so please provide the number of requests for each language in 2019 and 2020.

Response:

Yes, Columbia tracks the number of phone translation requests however, this is only available at the Smithfield Customer Care Center site level. The PA calls are handled through the Smithfield location, along with 4 other Columbia territories, and the detail in regards to PA only are not available.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-023:

Is Columbia currently holding any security deposits for any confirmed low income customers? If the answer to this question is yes, please identify the number of customers for whom this applies and the aggregate dollar amount of security deposits collected.

Response:

Yes. Currently Columbia is holding 1,494 security deposits for customers that have identified as low income. The aggregate dollar amount of security deposits collected is $239,277.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-032:

Does Columbia have a language access plan or procedure? Please provide a copy of any such plan or procedure, including any language needs assessments performed by the Company or a third party.

Response:

Columbia's language access procedures involve multiple channels of translation to ensure that customers receive information in their language.

1. Website:
   The www.columbiagaspa.com website features a Google Translate "Select Language" drop-down widget in the upper right hand corner of every navigable page on the site. In addition to the default English setting, visitors to the site can translate content to Spanish, Portuguese, Korean, Japanese, German, French, and Simplified Chinese.

2. Customer Care Center (CCC):
   When a person contacts Columbia Gas through the Customer Care Center (CCC), there is a Spanish prompt at the front end of the automatic phone system (IVR). When selected, the caller is routed to a Customer Service Representative (CSR). The CSR will engage an interpreter from our 3rd party interpreter vendor, Language Line, and they will begin a 3-way conversation with the customer.

   All Customer Service Representatives are trained on the use of our 3rd party translation service, Language Line, which offers 240 languages.

3. Field Personnel:
   Field employees interacting with the public have access to the Language Line translation service through their mobile phones.

The employee calls Language Line and is prompted to enter a language option (1 - for Spanish, 2 - for all other languages or to reach an agent). When further prompted, they enter their Client identification number, then their employee identification number.

They are placed on hold momentarily and an interpreter is added to their call. If it is a non-Spanish call, the employee will advise which language is needed and wait for the correct interpreter to join the call.

Once the correct interpreter is on the line, the employee continues with the call, and they are encouraged to use the "speaker" function on their phone to be able to add the customer to the conversation.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-033:

Please provide any needs assessment completed by or for Columbia, or within Columbia's possession, regarding the locations and numbers of limited English proficient Columbia customers.

Response:

To determine needs for areas with limited English proficient Columbia customers, the company uses the American Community Survey conducted by the Census Bureau. The Census Bureau's American Community Survey collects answers to create statistics used by federal and state agencies. It is the premier source for detailed population and housing information in the United States. (2018 is the last year available from the Census ACS 1-Year Estimate.)

Source— United States Census Bureau
LANGUAGE SPOKEN AT HOME
Survey Program: American Community Survey
TableID: S1601
Product: 2018: ACS 1-Year Estimates Subject Table

American Community Survey website:
https://www.census.gov/programs-surveys/acs

The counties where Columbia delivers natural gas where the percentage of "Language Spoken At Home" for languages other than English (where the population is identified as "Speak English less than very well" over 2.0 percent) are Adams County, Allegheny County, Centre County, Franklin County, Indiana County, and York County.

Columbia Gas County - Territory	LANGUAGE SPOKEN AT HOME	LANGUAGE SPOKEN AT HOME Language other than English Speak English less than very well	Percent LANGUAGE SPOKEN AT HOME Language other than English Speak English less than very well
Adams County	96868	2767	2.9
Allegheny County	1161245	26155	2.3
Centre County	155000	6086	3.9
Franklin County	144344	3491	2.4
Indiana County	81694	1989	2.4
York County	418500	11388	2.7

There are no counties meeting a threshold of 5% or more in Columbia's service territory with a language other than English.

Columbia Gas County - Territory	LANGUAGE SPOKEN AT HOME	LANGUAGE SPOKEN AT HOME English only	Percent LANGUAGE SPOKEN AT HOME English only	LANGUAGE SPOKEN AT HOME Language other than English Speak English less than very well	Percent LANGUAGE SPOKEN AT HOME Language other than English Speak English less than very well
Adams County	96868	90866	93.8	2767	2.9
Allegheny County	1161245	1076080	92.7	26155	2.3
Armstrong County	63060	61589	97.7	378	0.6
Beaver County	158345	153721	97.1	1460	0.9
Bedford County	46187	44979	97.4	384	0.8
Butler County	176960	171097	96.7	1566	0.9
Centre County	155000	136973	88.4	6086	3.9
Clarion County	36867	35291	95.7	437	1.2
Clearfield County	76542	73288	95.7	1399	1.8
Elk County	29010	28637	98.7	123	0.4
Fayette County	125602	121942	97.1	1035	0.8
Franklin County	144344	134921	93.5	3491	2.4
Fulton County	13783	13598	98.7	34	0.2
Greene County	35205	34204	97.2	227	0.6
Indiana County	81694	76343	93.4	1989	2.4
Jefferson County	41598	39648	95.3	462	1.1
Lawrence County	82934	79423	95.8	1247	1.5
McKean County	39715	38515	97	215	0.5
Mercer County	107181	102540	95.7	1494	1.4
Somerset County	71515	68441	95.7	1112	1.6

Venango County	49726	48829	98.2	275	0.6
Warren County	38062	36988	97.2	335	0.9
Washington County	197027	190897	96.9	1593	0.8
Westmoreland County	338555	329705	97.4	2339	0.7
York County	418500	387072	92.5	11388	2.7

APPENDIX C – EASUM Report

Pennsylvania Department of Human Services, Energy Assistance Summary (EASUM) – June 12, 2021

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Energy Assistance Summary (EASUM)

9/27/2020 - 6/10/2021

STATE WIDE

Cash Demographic Report (LIH660-R01)

	ITEM	COUNT	AMOUNT	%	AVG
HOUSING	Owner	111,299	$29,816,636	37	$268
	Renter	145,529	$41,926,966	48	$288
	RenterWithHeat	4,008	$580,518	1	$145
	SubsidizedWithHeat	60	$21,744	0	$362
	SubsidizedNoHeat	37,658	$11,071,149	12	$294
	Roomer	199	$40,598	0	$204
	Other	4,098	$1,364,547	1	$333
RACE	AmericanIndian	695	$206,619	0	$297
	Other	26,110	$7,456,629	9	$286
	NativeHawaiian	338	$111,425	0	$330
	Black	76,952	$22,330,916	25	$290
	White	189,459	$52,113,982	63	$275
	Asian	5,658	$1,530,662	2	$271
	Unknown	3,639	$1,071,925	1	$295
DISABLED	YES	35,790	$8,093,591	12	$226
	NO	266,983	$76,707,896	88	$287
AGE 60 & ABV	YES	119,525	$28,029,292	39	$235
	NO	183,326	$56,792,866	61	$310
AGE 5 & BLW	YES	55,516	$16,532,099	18	$298
	NO	247,335	$68,290,059	82	$276
PAY_TYPE	DIRECT	4,925	$1,096,384	2	$223
	PROVIDER	298,979	$84,011,931	98	$281
REFUNDS		4,102	$891,045		$217

AVERAGE HOUSEHOLD SIZE: 3.16

* Counts, Amounts ($), % and AVG from HOUSING, RACE, DISABLED, OVER-60 and INCOME RANGE category are from Regular payments only

** Counts, Amounts ($), % and AVG from PAY_TYPE category are from All Payment Types (Regular, Reissue, Secondpay, Underpay and Extraordinary)

*** Counts, Amounts ($), % and AVG from PAYMENT_SENT category are from All Payment Types (Regular, Reissue, Secondpay, Underpay and Extraordinary)

	ITEM	COUNT	AMOUNT	%	AVG
PAYMENT SENT	Electric	99,419	$27,933,892	33	$281
	FuelOil	46,509	$13,786,238	15	$296
	Coal	1,650	$398,486	1	$242
	NaturalGas	140,621	$38,567,297	46	$274
	Kerosene	3,181	$1,009,583	1	$317
	Propane	9,588	$2,580,628	3	$269
	WoodOrOther	1,084	$312,277	0	$288
	BlendedFuel	799	$233,757	0	$293
INCOME RANGE	0 - 999	16,490	$14,916,062	5	$905
	1000 - 1999	2,370	$2,000,654	1	$844
	2000 - 2999	2,332	$1,830,372	1	$785
	3000 - 3999	3,184	$2,019,428	1	$634
	4000 - 4999	3,499	$1,979,628	1	$566
	5000 - 5999	3,722	$1,691,646	1	$454
	6000 - 6999	4,693	$1,859,675	2	$396
	7000 - 7999	5,386	$1,874,108	2	$348
	8000 - 8999	7,733	$2,339,151	3	$302
	9000 - 9999	49,967	$13,048,126	16	$261
	10000 - 10999	15,761	$3,640,716	5	$231
	11000 - 11999	14,720	$3,118,796	5	$212
	12000 - 12999	16,070	$3,272,655	5	$204
	13000 - 13999	15,676	$3,127,889	5	$200
	14000 - 14999	17,723	$3,519,221	6	$199
	15000 - 15999	15,192	$3,016,761	5	$199
	16000 - 16999	14,910	$2,960,200	5	$199
	17000 - 17999	11,891	$2,362,500	4	$199
	18000 - 18999	10,369	$2,063,400	3	$199
	19000 - 19999	11,099	$2,208,900	4	$199
	> 19999	60,046	$11,964,779	20	$199
PAYMENT TYPE	Regular	302,851	$84,822,158		$280
	Reissue	170	$49,069		$289
	Secondpay	593	$162,955		$275
	Underpay	142	$28,576		$201
	Extraordinary	148	$45,557		$308
TOTAL PMT		303,904	$85,108,315		$280
RECOUPMENTS		218	$48,985		$225
NET PAID			$85,059,330		
PMT SUB TYPE	APD	0	$0		$0
	STD	303,904	$85,108,315		$280

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

SURREBUTTAL TESTIMONY OF HARRY GELLER

ON BEHALF OF

THE COALITION FOR AFFORDABLE UTILITY SERVICES AND

ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

July 27, 2021

PREPARED SURREBUTTAL TESTIMONY OF HARRY GELLER

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

A: My name is Harry S. Geller. I am an attorney. I am retired as the Executive Director of the Pennsylvania Utility Law Project (PULP). I maintain an office at 118 Locust St., Harrisburg, PA 17101 for the purpose of providing consulting services.

Q: Did you previously submit testimony in this proceeding?

A: Yes, I submitted direct testimony that was pre-marked as CAUSE-PA Statement 1.

Q: What is the purpose of your Surrebuttal Testimony?

A: My surrebuttal testimony responds to the rebuttal testimony of Columbia Gas of Pennsylvania, Inc. (CPA, Columbia, or Company) witness Melissa Bell[1] regarding my recommendations that Columbia's proposed residential fixed customer charge and Rider RNA should be rejected and Columbia witness Deborah Davis[2] regarding recommendations about universal service programs, security deposit programs, and other customer service issues. I will also address the rebuttal testimony of Office of Consumer Advocate (OCA) witness Roger Colton[3] and Bureau of Investigation and Enforcement (I&E) witness John Zalesky[4] regarding recommendations that I made in my direct testimony regarding Columbia's universal service programs and the rates paid by participants in Columbia's Customer Assistance Program (CAP).

My surrebuttal testimony will not address every issue raised or otherwise discussed by these or other witnesses in rebuttal. Absence of response to any specific recommendation or position of any witness does not indicate my agreement. Unless required for context in providing

[1] CPA St. 3-R.
[2] CPA St. 13-R.
[3] OCA St. 4-R.
[4] I&E St. 1-R.

a further response to rebuttal testimony, I will not reiterate the extensive arguments and evidence that I provided in my direct and rebuttal testimony. To the extent an argument raised by any party in rebuttal was already sufficiently addressed in direct, I do not intend to respond, and stand firmly on the evaluation, analysis, and recommendations contained in my direct testimony.

Q: How is your testimony organized?

A: I will begin by responding to the rebuttal testimony of CPA witnesses Melissa Bell regarding my recommendations that CPA's Rider RNA be rejected, and that CPA should not increase its fixed monthly customer charge. I will then address the rebuttal testimony of Columbia witness Deborah Davis, OCA witness Roger Colton, and I&E witness John Zalesky regarding my recommendations about Columbia's universal service programs and CAP rates. Finally, I will respond to Ms. Davis's rebuttal testimony regarding my recommendations about the Company's security deposit collections policies.

I. FIXED CHARGE AND RIDER RNA

Q: Did you provide a recommendation in your direct testimony regarding CPA's fixed monthly customer charge and its proposed Revenue Normalization Adjustment?

A: Yes. In my direct testimony, I recommended that the Commission reject CPA's proposal to increase its fixed residential customer charge. I explained that raising the fixed charge impedes a customers' ability to mitigate the impact of the proposed rate increase through conservation and energy efficiency, thus undermining the explicit goals of LIURP to help low-income customers to reduce their bills.[5] I also recommended that CPA's Rider RNA be rejected for similar reasons.[6] I

[5] CAUSE-PA St. 1 at 28-31.
[6] Id. at 36-38.

recommended that if the Commission does approve Rider RNA, Columbia's confirmed low income customers should be exempt from the rider.[7]

Q: Please summarize the Company's response to these recommendations.

A: Columbia witness Melissa Bell responded to my recommendations by pointing out that, theoretically, if the Company's full proposed residential increase is approved, LIURP customers would pay less per month under the Company's proposed rate structure than if the full proposed increase is placed on the volumetric charge, because LIURP customers remain high users after treatment.[8] She pointed out that the average usage per LIURP customer was 154.7 Dth for the year 2020 and 156.3 Dth for the year 2019, and that the average usage per customer for rate schedule RSS is 6.9 Dth per month – or 82.8 Dth per year.[9] Ms. Bell argues that assigning more of the rate increase to the volumetric charge will cost more for these high usage customers.[10] Ms. Bell also asserts that the Rider RNA only puts a portion of the cost of the customer's reduced energy usage back on their bill and spreads the rest across all customers, thus customers would still experience savings from conservation efforts.[11]

Q: How do you respond to Ms. Bell's assertions regarding the usage levels of low-income customers as they relate to the fixed charge increase and Rider RNA?

A: I stand by my recommendation that the fixed charge should not be increased, and that the Rider RNA should be rejected. I explained at length in my direct testimony the impact that the proposed fixed charge increase would have on low-income households and the need for these customers to be able to mitigate the impact of any rate increase through conservation measures,

[7] Id.
[8] CPA St. 3-R at 19.
[9] Id.
[10] Id.
[11] Id. at 37.

including though LIURP.[12] The simple fact is that increases to the volumetric charge can be mitigated through conservation measures, whereas increases to the fixed charge cannot. Energy efficiency and conservation can be highly effective at helping to control CAP customer bills, providing savings to both the CAP customer and to other residential ratepayers - including non-CAP low-income customers - who pay for CAP through rates. Increasing the fixed customer charge threatens the ability for low-income households to effectively reduce their bill through energy efficiency and conservation, further exacerbating unaffordability. I also remain concerned that the Rider RNA will erode potential bill savings from usage reduction, which would negatively impact on the ability of low-income households to mitigate the impact of the rate increase through usage reduction thus undercutting the ability of LIURP to reduce customer bills.

Ms. Bell argues that usage rates for LIURP participants post treatment remain high compared to average residential customers, and that this proves a high fixed charge rate structure is more beneficial to low income households.[13] Ms. Bell's argument further bolsters my recommendations that the Company needs to improve the effectiveness of its LIURP program at reducing customer usage, especially for the highest users, and that additional funding is necessary to allow the program to provide deeper measures and remediate health and safety issues that otherwise prevent the delivery of comprehensive energy efficiency services.[14] It also suggests that Columbia may not be installing all available energy efficiency measures while in the home, and may need to improve its post-LIURP services to ensure participants are served in a holistic manner. But it does not suggest that a high fixed charge rate structure is better for low-income households.

[12] CAUSE-PA St. 1 at 30-32.
[13] CPA St. 3-R at 19.
[14] CAUSE-PA St. 1 at 24-27.

Rate design should advance energy efficiency goals and should be coupled with strong efficiency programs to help those who cannot afford to adopt efficiency measures on their own.

II. Universal Service Programs and Customer Assistance Program Rates

Q: Did you make recommendations in this proceeding regarding the Company's Universal Service Programs and Customer Assistance Program Rates?

A: Yes. In my direct testimony, I recommended that, consistent with the Commission's CAP Policy Statement, Columbia reduce its Percentage of Income CAP Rate to 4% of household income for CAP participants with income at or below 50% FPL and 6% of household income for CAP participants with income between 51-150% FPL, and that the Company increase the LIURP Health and Safety Pilot Program and extend the program until 2023.[15] My recommendations were targeted rate mitigation measures based on data indicating that Columbia's CAP rates are currently unaffordable, and that existing unaffordability would be exacerbated if Columbia's rates were to increase – thereby increasing the Companies' other CAP rate options, and causing more households to pay the percentage of income CAP rate.[16] Improving the affordability of CAP rates, and focusing enhanced usage reduction services on high usage customers with critical health and safety issues in the home, can help to mitigate the impact of the rate increase on Columbia's most vulnerable customers.

Q: Please summarize the responses of other parties to these recommendations.

A: Regarding my recommendation that the Company adjust its Percentage of Income CAP rates, Columbia witness Deborah Davis responds that the proposed revisions would cost approximately $1 million annually, and that additional control features may be necessary because

[15] CAUSE-PA St.1 at 35.
[16] Id.

of increased enrollment.[17] Ms. Davis also points out that a majority of Columbia's CAP customers currently have an asked to pay amount less than 6% of income, while customers at or below 50% FPL are asked to pay an average of 6.75%.[18] She asserts that availability of LIHEAP should be taken into consideration regarding the affordability of CAP rates for customers at or below 50% FPL.[19] OCA witness Roger Colton argues that consideration of Columbia's CAP rates should be delayed to its next USECP proceeding.[20] I&E witness John Zaleski argues that my recommendations about the Health and Safety pilot should be delayed to the Company's next USECP proceeding.[21]

Regarding my recommendations about expanding the LIURP Health and Safety Pilot, Ms. Davis indicates that Columbia recognizes that the model needs to be adjusted to increase the number of customers that the program can assist.[22] She indicates that the Company's general LIURP budget has a large carryover from 2020 and anticipates there will be a carryover this year as well. [23] She indicates the Company would support using this carryover to increase the health and safety budget and extend the pilot out to 2023. If homes can be identified & the pilot is successful in 2022, the budget for 2023 would be increased to $600,000.[24] I&E witness John Zalesky argues that extension of the Health and Safety Pilot should be delayed until Columbia's next USECP proceeding. [25]

[17] CPA St. 13-R at 15-16.
[18] Id.
[19] Id.
[20] OCA St. 4-R at 1-2.
[21] I&E St. 1-R at 7-9.
[22] CPA St. 3-R at 22.
[23] Id.
[24] Id.
[25] I&E St. 1-R at 7-9.

Q: Do you agree with Ms. Davis that before the Company adopts the Commission's recommended CAP energy burdens, Columbia would need to offset that amount by reviewing how participant current benefits could be reduced?

A: No. I stand by my position in my direct testimony that Columbia should take immediate action to address its unaffordable CAP rates.[26] As Ms. Davis points out, there will be a cost for this change. However, I believe that the Company's projected cost of adopting the revised energy burden – approximately $0.24 per month for residential customers[27] – is reasonable considering the effect that it will have to mitigate the significant negative consequences of energy poverty, and for all of the other far-ranging individual and societal benefits associated with improved energy affordability.[28] I reject the implication by Ms. Davis that such a change toward affordable rates be undertaken only after Columbia has determined a way to offset those costs by reducing or otherwise narrowing the availability of assistance available to low income families through the program. I submit that the situation is just the opposite: Columbia's proposed rate increase should be approved only after CAP rates are reduced to a level of affordability in line with the Commission's current maximum energy burden policy. It is contrary to the intent of the Gas Choice Act and the Commission's recent determination of the appropriate level of energy burden to be borne by a CAP customer, that any movement toward achievement of affordable rates must be predicated on a loss or reduction of current benefits.

Q: Do you agree with Ms. Davis that not including LIHEAP dollars in the calculation of CAP energy burdens would unfairly burden residential customers funding the program?

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[26] CAUSE-PA St. 1 at 22-23.
[27] Id., at 22, Table 2.
[28] CAUSE-PA St. 1 at 22-23.

A: No. The Commission addressed this issue in its Final CAP Policy Statement Order by specifically eliminating provisions in the CAP Policy Statement that a customer must direct the LIHEAP grant to the utility sponsoring the CAP or otherwise face a penalty or reduced CAP assistance if they did not apply for LIHEAP.[29] The Commission explained:

> As low-income customers may participate in more than one CAP – or may use their LIHEAP grant to obtain a deliverable fuel source – these provisions are no longer appropriate as they could require households to choose between CAPs or between a CAP and a necessary fuel delivery. Further, verifying LIHEAP participation and imposing a monetary penalty on the CAP account could be administratively burdensome on the utilities and could result in creating more utility debt for financially vulnerable households.[30]

Many of Columbia's customers direct their LIHEAP grants to their electric utility or a deliverable fuel source necessary to heat some portion of their home, some CAP-eligible households may not qualify for LIHEAP, and some may experience greater difficulty even applying.[31] LIHEAP is also a finite source of federal funding and is not an entitlement program. Each year, the availability of LIHEAP is dependent on the federal government to approve the program. While funding for LIHEAP has been relatively stable, the program was proposed to be cut in its entirety in recent years.

For these reasons, I reject Ms. Davis' assertion that LIHEAP dollars must be considered in the calculation of CAP energy burdens.

Q: Mr. Colton argues that your recommendations should be deferred to Columbia's next USECP proceeding.[32] What is your response?

[29] Final CAP Policy Statement Order at 52, 98, 101-102.
[30] Id. at 50-51.
[31] Id. at 51.
[32] OCA St. 4-R at 2.

A: I disagree. Columbia is proposing to increase residential rates *now*, in the context of this proceeding. If approved, Columbia's rate increase will have a direct and immediate impact on rates charged to most Columbia's CAP customers – exacerbating existing levels of unaffordability.[33] Columbia's next USECP consideration, on the other hand, is not scheduled to take effect until 2024 and, considering the Commission's current backlog of USECP proceedings, may not be reviewed, and approved for quite some time thereafter. Considering a rate increase now while deferring consideration of how to ameliorate the effect of that increase on economically vulnerable consumers through modification of Columbia's CAP rates or its LIURP (or any other universal service issue) would effectively deprive low-income customers of needed assistance, requiring CAP customers and other low-income households to pay categorically unaffordable rates for at least two years – and quite possibly even longer.

To explain, Columbia is due to file its 2024-2028 USECP on April 1, 2023, for the plan to take effect in 2024. This is already a long time for CAP customers to continue to pay rates that the Commission has already deemed unaffordable in its Final CAP Policy Statement Order. However, given the substantial backlog of Universal Service and Energy Conservation Plan proceedings pending before the Commission, it is unlikely that the plan will take effect in 2024. For example, Peoples Natural Gas timely filed its proposed 2019-2021 USECP on July 2, 2018, scheduled to go into effect in the year 2019.[34] The tentative order in this case was not issued until August 27, 2020.[35] As of this writing, over three years has passed since the proposed plan was filed and this case remains pending.

[33] CAUSE-PA St. 1 at 18-19.
[34] Peoples Natural Gas USECP 2019-2024, M-2018-3003177.
[35] Peoples Natural Gas USECP 2019-2024, M-2018-3003177, Tentative Order (Aug. 27, 2020).

Likewise, PECO Energy Company filed its proposed 2019-2024 USECP as scheduled on November 1, 2018, to take effect in 2019; however, the Commission did not enter a tentative order in that proceeding until May 6, 2021, more than two years after the plan was scheduled to take effect.[36] The Comment period in that proceeding ends August 24, 2021, but there is no timeline for the Commission to reach a final decision in the case.

Duquesne Light timely filed its proposed 2020-2022 USECP on February 28, 2019, to take effect in the year 2020.[37] This case is also still pending. The tentative order in that case was not issued until November 19, 2020.[38] In a Joint Statement issued with the Tentative Order, the Commission's Chairman and Vice Chairman stated:

> There are additional policy matters in the company's proposed plan that, in our opinion, require further clarification prior to approval. However, the adoption of the proposed energy burden standards is not one of them as **we have already deemed these standards to be reasonable, affordable, and necessary under our new Policy Statement**. Now more than ever, there are households in need of greater assistance given the calamitous economic effects caused by the current health crisis. We believe Duquesne's proposed customer assistance program will provide the much-needed relief that so many are seeking. We urge the company to begin implementation as quickly as possible at the conclusion of this process.[39]

If Columbia's USECP is subject to similar delays, it could take until 2026 or later before the plan would take effect. This is an unreasonably long time to permit CAP customers to continue to be forced to pay rates that the Commission has already deemed unaffordable and unreasonable. On the other hand, the Commission has already deemed these new energy burden standards to be reasonable, affordable, and necessary.[40] It is unfair and unreasonable to force customers to continue to pay unaffordable and unreasonable rates pending a future proceeding with an indefinite

[36] PECO Energy Co. 2019-2024 USECP, M-2018-3005795.
[37] Duquesne Light Co. 2020-2022 USECP, M-2019-3008227, Tentative Order (November 19, 2020).
[38] Id.
[39] Joint Statement of Chairman Gladys Brown Dutrieuille and Vice Chairman David W. Sweet (Nov. 19, 2020)
[40] Id.

timeframe to take place years into the future. It is far more reasonable to adjust these rates now, as part of this pending rate case.

Q: How do you respond to Mr. Colton's assertion that our recommendation to lower CAP Rates does not consider customers who are just over the eligibility threshold for the program?

A: I share Mr. Colton's concern for customers who are just over the eligibility for CAP who pay for universal service costs through rates. However, the fact remains that the Natural Gas Choice Act is the basis of the direction for Columbia to charge its low-income customers affordable rates. The Commission has determined that Customer Assistance Programs are the method to achieve those rates and has designated the appropriate energy burden to be charged and the eligibility level to be used. The solution to address the affordability needs of those customers not presently eligible for or enrolled in CAP should not be to continue charging CAP customers categorically unaffordable rates. The better solution is to improve CAP outreach and to ensure there is programing in place for all those in need of assistance.

Households just over the eligibility for CAP do have access to Hardship Funds and LIURP assistance to help address and remediate high usage and financial hardship that may cause households with slightly higher income to fall behind on their bills.[41] Moreover, the relative scale of unaffordability is far different for those who are "near poor" – as Mr. Colton describes them – compared to those who are income eligible for CAP, the program designated by statute and the Commission to address the issue of affordability. According to Mr. Colton's Home Energy Affordability Gap study, published most recently in April 2021, Pennsylvania households with

[41] PECO USECP 2016-2018 at 14, 16 (LIURP eligibility extends up to 200% FPL, MEAF extends up to 175% FPL).

income between 150-185% FPL have an average combined home energy burden of 7% (inclusive of electricity and heating costs), and those with income between 185-200% FPL have an average combined home energy burden of 6%.[42] These averages are well below the Commission's recommended energy burden threshold of 10% for households with income between 51-150% FPL,[43] and are substantially lower than the energy burden standards that Columbia currently follows. As noted above, the Company's projected cost of adopting the revised energy burden standards is just $0.24 per month for residential customers.[44] This would not have an appreciable impact on the home energy burden of the body of Columbia's non-CAP customers.

Q: Do you agree with Ms. Davis's suggested modifications to your recommendation about the Company's LIURP Health and Safety Pilot?

A: To an extent. I agree that the adjusting the model to recognize savings that can be realized through a reduction of shortfall would increase the Health & Safety allowance providing for homes with lower usage to have an allowance that would be sufficient to remediate the reason for the deferral.[45] Providing a greater allowance and increasing the budget for the program will increase the number of customers eligible for assistance and the measures Columbia can install.

However, I disagree that the additional funds to extend the program should be taken from the existing LIURP budget.[46] As pointed out by Columbia witness Melissa Bell, Columbia's current LIURP customers still have exceedingly high usage, even after treatment.[47] As Ms. Bell points out, Columbia's LIURP customers have average usage of 154.7 Dth for the year 2020,

[42] Roger Colton, The Home Energy Affordability Gap: Pennsylvania 2020, Pa. Fact Sheet (published April 2021), *available at* http://www.homeenergyaffordabilitygap.com/03a_affordabilityData.html. Attached hereto as Appendix A.
[43] 52 Pa. Code § 69.265(2)(i).
[44] CAUSE-PA St. 1 at 22, Table 2.
[45] CPA St. 13-R at 22.
[46] Id.
[47] CPA St. 3-R at 20.

which is approximately 187% the average usage for an average residential customer (6.9 Dth per month/ 82.8 Dth per year).[48] Based on this persistent high usage among LIURP customers, Columbia's existing LIURP funds would be better spent by improving the level of services provided in each home and/or revisiting LIURP participants with persistently high usage to find additional ways to help these customers further reduce their usage to levels more closely reflecting the average usage among residential customers. The Health and Safety Pilot funding should be in addition to the existing budget to maximize the ability of the Company's LIURP to remediate this persistent high usage.

Q: What is your response to Mr. Zalesky's argument that your recommendations about Columbia's Health and Safety Pilot be deferred to the Company's next USECP proceeding?[49]

A: Mr. Zalesky's suggestion is not an adequate solution. As I explained above, Columbia is not due to file its next USECP until April 1, 2023, and there is currently a multi-year backup for the Commission to approve proposed USECPs. The Health and Safety Pilot is set to expire in 2022. In her rebuttal testimony, Ms. Davis indicated Columbia's support for the program, but indicated it was in need of vital improvements.[50] She pointed out that the Health and Safety Pilot was scheduled to begin upon approval in 2020 but was suspended due to the COVID-19 pandemic.[51] She further explained that the current allowance for projects is often insufficient to address the primary obstacle to weatherization and indicated that Columbia recognizes that the model needs to be adjusted to increase the number of customers that can be assisted.[52] Thus,

[48] Id. at 19-20.
[49] I&E St. 1-R at 7-8.
[50] CPA St. 13-R at 21-22.
[51] Id.
[52] Id.

delaying the extension of the pilot until the Company's USECP proceeding would cause the program to continue to operate without making currently needed improvements and potentially cause it to go dark for a substantial period of time before an extension can be approved. During this time, vulnerable customers would be deprived of vital weatherization and health and safety measures.

III. SECURITY DEPOSITS

Q: Did you make observations and recommendations in this proceeding regarding Columbia's security deposit policies?

A: Yes. Through discovery, the Company indicated that it was holding 1,494 security deposits for confirmed low-income customers, totaling $239,277.[53] In my direct testimony I recommended that Columbia refund all deposits held for customers with confirmed low income within 30 days. Going forward, I recommended that Columbia review currently held security deposits monthly and issue a bill credit or refund for any deposit previously collected from a confirmed low-income customer.

Q: What was the Company's response to your recommendation?

A: Ms. Davis indicated that the Company does not charge a security deposit if the customer self-reports income at or below 150% FPL at any point during the call to establish service..[54] However, if the customer does not self-identify as low income on the initial call, the Company charges a customer a security deposit.[55] If that customer later reports low income, the Company

[53] CAUSE-PA to CPA I-23. Attached hereto as Appendix B.
[54] CPA St. 13 at 24-25.
[55] Id.

requires either receipt of LIHEAP funds or CAP enrollment in order for the Company to issue a refund.[56] Ms. Davis asserts that this policy is compliant with the regulation.

Q: Do you agree?

A: No. There are many reasons that an otherwise income-eligible customer may not be able to enroll in CAP or receive LIHEAP funds or may choose not to participate in these programs. The Company should not require CAP enrollment or receipt of LIHEAP funds as a condition of releasing a security deposit collected from a low-income household. I am advised by counsel for CAUSE-PA that the legal aspects of this issue will be addressed further through briefing; however, I will note that the Commission has already issued explicit guidance on this issue and was clear that a low-income household does not need to enroll in CAP or another universal service program for the prohibition on security deposits to apply.[57]

In its Attachment A to its Ch. 56 Rulemaking Order, the Commission clarified that the prohibition on collecting security deposits from low-income customers is, "referring to eligibility based upon the customer's household income – *not on other miscellaneous eligibility criteria that can vary by utility*."[58] The Commission also stated:

> Regarding the concerns expressed about this same section by LICRG that it is eligibility and not actual enrollment into CAP that determines the customer's exemption from deposit requirements, we agree and point out that ***this section specifies "eligible,"*** <u>***not***</u> ***"enrolled" or "participating."*** We think this language is sufficient direction that the customer only has to be "eligible" and not actually enrolled in CAP to be exempt from a deposit request.[59]

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[56] <u>Id.</u>
[57] 52 Pa. Code § 56.32(e).
[58] Rulemaking to Amend the Provisions of 52 Pa. Code, Chapter 56 to Comply with the Amended Provisions of 66 Pa. C.S. Ch. 14, L-2015-2508421, Final Rulemaking Order, Attach. One at 48 (Feb. 28, 2019).
[59] <u>Id</u>. (emphasis added).

The Commission also requires both verbal notice of the exemption, as well as instructions for how to verify income should be provided to applicants and customers *at the time the security deposit is assessed*.[60]

Columbia accepts verbal income information on the initial call when the security deposit is assessed. It should consistently accept the same form of information in assessing security deposit information for all its customers who are at or below 150% FPL. Customers at this income level need every dollar available to be able to afford their monthly expenses. This is true regardless of whether the customer identifies as low income on the initial call to set up service, or whether the customer subsequently becomes low income and informs the Company at that time.

Q: Does this conclude your surrebuttal testimony?

A: Yes.

[60] Id.; see also 52 Pa. Code §§ 56.36, 56.286.

CAUSE-PA ST. 1

APPENDIX A

The Home Energy Affordability Gap: Pennsylvania 2020, Pa. Fact Sheet

PENNSYLVANIA

THE HOME ENERGY AFFORDABILITY GAP 2020

(2ND SERIES) PUBLISHED APRIL 2021

Finding #1

Poverty Level	Home Energy Burden
Below 50%	29%
50 – 100%	16%
100 – 125%	11%
125 – 150%	9%
150 – 185%	7%
185% - 200%	6%

Home energy is a crippling financial burden for low-income Pennsylvania households. Pennsylvania households with incomes of below 50% of the Federal Poverty Level pay 29% of their annual income simply for their home energy bills.

Home energy unaffordability, however, is not only the province of the very poor. Bills for households with incomes between 150% and 185% of Poverty take up 7% of income. Pennsylvania households with incomes between 185% and 200% of the Federal Poverty Level have energy bills equal to 6% of income.

Finding #2

Poverty Level	Number of Households	
	Last Year	This Year
Below 50%	290,835	283,671
50 – 100%	351,184	346,035
100 – 125%	198,793	192,742
125 – 150%	199,025	193,711
150 – 185%	295,130	294,005
185% - 200%	127,155	126,068
Total < 200%	1,462,122	1,436,232

The number of households facing unaffordable home energy burdens is staggering. According to the most recent five-year American Community Survey, nearly 284,000 Pennsylvania households live with income at or below 50% of the Federal Poverty Level and face a home energy burden of 29%. And more than 346,000 *additional* Pennsylvania households live with incomes between 50% and 100% of the Federal Poverty Level and face a home energy burden of 16%.

In 2020 the total number of Pennsylvania households below 200% of the Federal Poverty Level stayed relatively constant from the prior year.

Finding #3

Home Energy Affordability Gap: 2011 (base year)	$1,872,227,794
Home Energy Affordability Gap: 2020 (current year)	$1,438,711,625
Home Energy Affordability Gap Index (2011 = 100)	76.8

The Home Energy Affordability Gap Index (2nd Series) indicates the extent to which the Home Energy Affordability Gap has increased between the base year and the current year. In Pennsylvania, this Index was 76.8 for 2020.

The Home Energy Affordability Gap Index (2nd Series) uses the year 2011 as its base year. The Index for 2011 is set equal to 100. A current year Index of more than 100 thus indicates that the Home Energy Affordability Gap for has increased since 2011. A current year Index of less than 100 indicates that the Home Energy Affordability Gap has decreased since 2011.

Finding #4

	Last Year	This Year
Gross LIHEAP Allocation ($000's)	$206,488	$181,869
Number of Households <150% FPL	1,039,837	1,016,159
Heating/Cooling Bills "Covered" by LIHEAP	186,025	169,496

Existing sources of energy assistance do not adequately address the Home Energy Affordability Gap in Pennsylvania. LIHEAP is the federal fuel assistance program designed to help pay low-income heating and cooling bills. The gross LIHEAP allocation to Pennsylvania was $181.9 million in 2020 and the number of average annual low-income heating and cooling bills "covered" by LIHEAP was 169,496.

In comparison, the gross LIHEAP allocation to Pennsylvania in 2019 reached $206.5 million and covered 186,025 average annual bills.

Finding #5

Primary Heating Fuel	Penetration by Tenure	
	Owner	Renter
Electricity	17%	36%
Natural gas	52%	49%
Fuel Oil	19%	9%
Propane	5%	3%
All other	7%	3%
Total	100%	100%

The Home Energy Affordability Gap in Pennsylvania is not solely a function of household incomes and fuel prices. It is also affected by the extent to which low-income households use each fuel. All other things equal, the Affordability Gap will be greater in areas where more households use more expensive fuels.

In 2020, the primary heating fuel for Pennsylvania homeowners was Natural Gas (52% of homeowners). The primary heating fuel for Pennsylvania renters was also Natural Gas (49% of renters).

Changes in the prices of home energy fuels over time are presented in Finding #6 below.

Finding #6

Fuel	2018 Price	2019 Price	2020 Price
Natural gas heating (ccf)	$1.140	$1.106	$1.110
Electric heating (kWh)	$0.147	$0.143	$0.144
Propane heating (gallon)	$3.225	$3.161	$2.286
Fuel Oil heating (gallon)	$3.021	$2.940	$2.943
Electric cooling (kWh)	$0.146	$0.145	$0.139

In Pennsylvania, natural gas prices stayed relatively constant during the 2019/2020 winter heating season. Fuel oil prices stayed relatively constant and propane prices fell 27.7%.

Heating season electric prices stayed relatively constant in the same period and cooling season electric prices fell 4.1%.

Home Energy Affordability Gap Dashboard -- Pennsylvania 2020 versus 2019

<table>
<tr>
<td colspan="2">AVERAGE DOLLAR AMOUNT
BY WHICH ACTUAL HOME ENERGY BILLS
EXCEEDED AFFORDABLE HOME ENERGY BILLS
FOR HOUSEHOLDS BELOW 200% OF POVERTY LEVEL.

2019: $1,137 per household

2020: $1,002 PER HOUSEHOLD</td>
<td>AVERAGE TOTAL HOME ENERGY
BURDEN FOR HOUSEHOLDS BELOW 50%
OF POVERTY LEVEL.

2019: 31% of household income

2020: 29% OF HOUSEHOLD INCOME</td>
</tr>
<tr>
<td>PERCENT OF INDIVIDUALS BELOW
100% OF POVERTY LEVEL.

2019: 13% of all individuals

2020: 12% OF ALL INDIVIDUALS</td>
<td colspan="2">NUMBER OF AVERAGE LOW-INCOME HEATING/COOLING
BILLS COVERED BY
FEDERAL HOME ENERGY ASSISTANCE.

2019: 186,025 bills covered

2020: 169,496 BILLS COVERED</td>
</tr>
<tr>
<td colspan="3">PRIMARY HEATING FUEL (2020):

HOMEOWNERS - NATURAL GAS *** TENANTS - NATURAL GAS</td>
</tr>
</table>

NOTES AND EXPLANATIONS

The 2012 Home Energy Affordability Gap, published in May 2013, introduced the 2nd Series of the annual Affordability Gap analysis. The 2012 Home Energy Affordability Gap going forward cannot be directly compared to the Affordability Gap (1st Series) for 2011 and earlier years. While remaining fundamentally the same, several improvements have been introduced in both data and methodology in the Affordability Gap (2nd Series).

The most fundamental change in the Home Energy Affordability Gap (2nd Series) is the move to a use of the American Community Survey (ACS) (5-year data) as the source of foundational demographic data. The Affordability Gap (1st Series) relied on the 2000 Census as its source of demographic data. The ACS (5-year data) offers several advantages compared to the Decennial Census. While year-to-year changes are smoothed out through use of 5-year averages, the ACS nonetheless is updated on an annual basis. As a result, numerous demographic inputs into the Affordability Gap (2nd Series) will reflect year-to-year changes on a county-by-county basis, including:

- The distribution of heating fuels by tenure;
- The average household size by tenure;
- The number of rooms per housing unit by tenure;
- The distribution of owner/renter status;
- The distribution of household size;
- The distribution of households by ratio of income to Poverty Level;

Data on housing unit size (both heated square feet and cooled square feet) is no longer calculated based on the number of rooms. Instead, Energy Information Administration/Department of Energy (EIA/DOE) data on square feet of heated and cooled living space per household member is used beginning with the Home Energy Affordability Gap (2nd Series). A distinction is now made between heated living space and cooled living space, rather than using total living space.

The change resulting in perhaps the greatest dollar difference in the aggregate and average Affordability Gap for each state is a change in the treatment of income for households with income at or below 50% of the Federal Poverty Level. In recent years, it has become more evident that income for households with income below 50% of Poverty Level is not normally distributed. Rather than using the mid-point of the Poverty range (i.e., 25% of Poverty Level) to determine income for these households, income is set somewhat higher (40% of Poverty). By setting income higher, both the average and aggregate Affordability Gap results not only for that Poverty range, but also for the state as a whole, will be lower. The Affordability Gap results for other Poverty ranges remain unaffected by this change.

Another change affecting both the aggregate and average Affordability Gap is a change in the definition of "low-income." The Home Energy Affordability Gap (2nd Series) has increased the definition of "low-income" to 200% of the Federal Poverty Level (up from 185% of Poverty). While this change may increase the aggregate Affordability Gap, it is likely to decrease the average Affordability Gap. Since more households are added to the analysis, the aggregate is likely to increase, but since the contribution of each additional household is less than the contributions of households with lower incomes, the overall average will most likely decrease.

Most of the Home Energy Affordability Gap calculation remains the same. All references to "states" include the District of Columbia as a "state." Low-income home energy bills are calculated in a two-step process: First, low-income energy consumption is calculated for the following end-uses: (1) space heating; (2) space cooling; (3) domestic hot water; and (4) electric appliances (including lighting and refrigeration). All space cooling and appliance consumption is assumed to involve only electricity. Second, usage is multiplied by a price per unit of energy by fuel type and end use by time of year. The price of electricity, for example, used for space cooling (cooling months), space heating (heating months), and appliances (total year) differs to account for the time of year in which the consumption is incurred.

Each state's Home Energy Affordability Gap is calculated on a county-by-county basis. Once total energy bills are determined for each county, each county is weighted by the percentage of persons at or below 200% of the Federal Poverty Level to the total statewide population at or below 200% of the Federal Poverty Level to derive a statewide result. Bills are calculated by end-use and summed before county weighting.

LIHEAP comparisons use gross allotments from annual baseline LIHEAP appropriations as reported by the federal LIHEAP office. They do not reflect supplemental appropriations or the release of LIHEAP "emergency" funds. The number of average heating/cooling bills covered by each state's LIHEAP allocation is determined by dividing the total base LIHEAP allocation for each state by the average heating/cooling bill in that state, the calculation of which is explained below. No dollars are set aside for administration; nor are Tribal set-asides considered.

State financial resources and utility-specific rate discounts are not considered in the calculation of the Affordability Gap. Rather, such funding should be considered available to fill the Affordability Gap. While the effect in any given state may perhaps seem to be the same, experience shows there to be an insufficiently authoritative source of state-by-state data, comprehensively updated on an annual basis, to be used as an input into the annual Affordability Gap calculation.

Energy bills are a function of the following primary factors:

- Tenure of household (owner/renter)
- Housing unit size (by tenure)
- Heating Degree Days (HDDs) and Cooling Degree Days (CDDs)
- Housing size (by tenure)
- Heating fuel mix (by tenure)
- Energy use intensities (by fuel and end use)

Bills are estimated using the U.S. Department of Energy's "energy intensities" published in the DOE's Residential Energy Consumption Survey (RECS). The energy intensities used for each state are those published for the Census Division in which the state is located. Heating Degree Days (HDDs) and Cooling Degree Days (CDDs) are obtained from the National Weather Service's Climate Prediction Center on a county-by-county basis for the entire country.

End-use consumption by fuel is multiplied by fuel-specific price data to derive annual bills. State price data for each end-use is obtained from the Energy Information Administration's (EIA) fuel-specific price reports (e.g., Natural Gas Monthly, Electric Power Monthly). State-specific data on fuel oil and kerosene is not available for all states. For those states in which these bulk fuels have insufficient penetration for state-specific prices to be published, prices from the Petroleum Administration for Defense Districts (PADD) of which the state is a part are used.

The Home Energy Affordability Gap Index (2nd Series) uses 2011 as its base year. The base year (2011) Index has been set equal to 100. A current year Index of more than 100 thus indicates that the Home Energy Affordability Gap has increased since 2011. A current year Index of less than 100 indicates that the Affordability Gap has decreased since 2011. The Affordability Gap Index was, in other words, re-set in 2011. The Affordability Gap Index (2nd Series) for 2012 and beyond cannot be compared to the Affordability Gap Index (1st Series) for 2011 and before.

The Home Energy Affordability Gap is a function of many variables, annual changes in which are now tracked for nearly all of them. For example, all other things equal: increases in income would result in decreases in the Affordability Gap; increases in relative penetrations of high-cost fuels would result in an increase in the Gap; increases in amount of heated or cooled square feet of living space would result in an increase in the Gap. Not all variables will result in a change in the Affordability Gap in the same direction. The annual Affordability Gap Index allows the reader to determine the net cumulative impact of these variables, but not the impact of individual variables.

Since the Affordability Gap is calculated assuming normal Heating Degree Days (HDDs) and Cooling Degree Days (CDDs), annual changes in weather do not have an impact on the Affordability Gap or on the Affordability Gap Index.

Price data for the various fuels underlying the calculation of the Home Energy Affordability Gap (2nd Series) was used from the following time periods:

Heating prices	
Natural gas	February 2020
Fuel oil ***	Week of 02/10/2020
Liquefied petroleum gas (LPG) ***	Week of 02/10/2020
Electricity	February 2020
Cooling prices	August 2020
Non-heating prices	
Natural gas	May 2020
Fuel oil ***	Week of 10/05/2020
Liquefied petroleum gas (LPG) ***	Week of 10/05/2020
Electricity	May 2020

*****Monthly bulk fuel prices are no longer published. Weekly bulk fuel prices are published during the heating months (October through March). The prices used are taken from the weeks most reflective of the end-uses to which they are to be applied. Prices from the middle of February best reflect heating season prices. Bulk fuel prices from October best reflect non-heating season prices.**

CAUSE-PA ST. 1

APPENDIX B

Interrogatory Response:

CAUSE-PA TO CPA I-23

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA)

Set 1

Question No. CAUSE-PA 1-023:

Is Columbia currently holding any security deposits for any confirmed low income customers? If the answer to this question is yes, please identify the number of customers for whom this applies and the aggregate dollar amount of security deposits collected.

Response:

Yes. Currently Columbia is holding 1,494 security deposits for customers that have identified as low income. The aggregate dollar amount of security deposits collected is $239,277.

EXHIBIT A
Representations to Investors
Culbertson

FROM INTERNET https://investors.nisource.com/company-information/default.aspx

(August 2, 2021)

COMPANY FACTS

Columbia Gas of Kentucky

- ✓ Second Largest Gas-Only local distribution company (LDC) in KY (~137K Customers)
- ✓ ~ 2,600 Miles of Pipe
- ✓ ~ 350 Miles of Bare Steel & Cast Iron
- ✓ ~ $327M Rate Base

Columbia Gas of Maryland

- ✓ Complementary to PA Operations (~34K Customers in MD)
- ✓ ~ 660 Miles of Pipe
- ✓ ~ 50 Miles of Bare Steel & Cast Iron
- ✓ ~ $149M Rate Base

Columbia Gas of Ohio

- ✓ Largest LDC in Ohio (~1.5M customers)
- ✓ ~ 20,200 Miles of Pipe
- ✓ ~ 2,000 Miles of Bare Steel & Cast Iron
- ✓ ~ $3.2B Rate Base

Columbia Gas of Pennsylvania

- ✓ Third Largest LDC in PA (~440K Customers)
- ✓ ~ 7,700 Miles of Pipe
- ✓ ~ 1,200 Miles of Bare Steel & Cast Iron
- ✓ ~ $1.9B Rate Base

Columbia Gas of Virginia

- ✓ Third Largest LDC in VA (~274K Customers)
- ✓ ~ 5,300 Miles of Pipe
- ✓ ~ 140 Miles of Bare Steel
- ✓ ~ $850M Rate Base

Indiana Gas (NIPSCO)

- ✓ Largest LDC in Indiana (~840K Customers)
- ✓ ~ 17,500 Miles of Pipe
- ✓ ~ 23 Miles of Bare Steel & Wrought Iron
- ✓ ~ $1.7B Rate Base

Exhibit B

Table derived from Facts Exhibit A

Culbertson

Company Facts that are reformatted and normalized.

Utility -- State	~ No. of Customers (In 000)	Miles of Pipe	Miles of pipe per customer	Rate Base ($ 000,000)	Rate Base Per Customer $
NIPSCO	840	17500	.020	1700	**2,024**
COH	1500	20200	.013	3200	2,133
CKY	137	2600	.019	327	2,387
CVA	274	5300	.019	850	3,102
CMD	34	660	.018	149	4,382
CPA	433	7700	.018	2400	**5,545**

CPA data was updated from information included in the Administrative Law Judge's Recommended Decision on December 4, 2020, Rate Case - R-2020-3018835. (Rate base $2,401,427,019 and ~433,000 customers -- ~ $5,545 per customer.

The figures are not adjusted for the *"stub service"*[1] [2]of which CPA provides

CPA data was updated from information included in the Administrative Law Judge's Recommended Decision on December 4, 2020, Rate Case - R-2020-3018835. (Rate base $2,401,427,019 and ~433,000 customers -- ~ $5,545 per customer.

[1] *18 CFR Part 201 - UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT* https://www.law.cornell.edu/cfr/text/18/part-201

[2] *Account 380 Services. A. This account shall include the cost installed of service pipes and accessories leading to the customers' premises. B. A complete service begins with the connection on the main and extends to but does not include the connection with the customer's meter. A **stub service** extends from the main to the property line, or the curb stop.*

Exhibit C
NiSource 10-K
Culbertson

For the fiscal year ended December 31, 2020 https://d18rn0p25nwr6d.cloudfront.net/CIK-0001111711/9f4ccf64-7861-4b15-936d-32aaaadeafa7.pdf (Page 118)

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our chief executive officer and chief financial officer, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. ***Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework,***[1] *the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. During 2020, we conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this annual report.*

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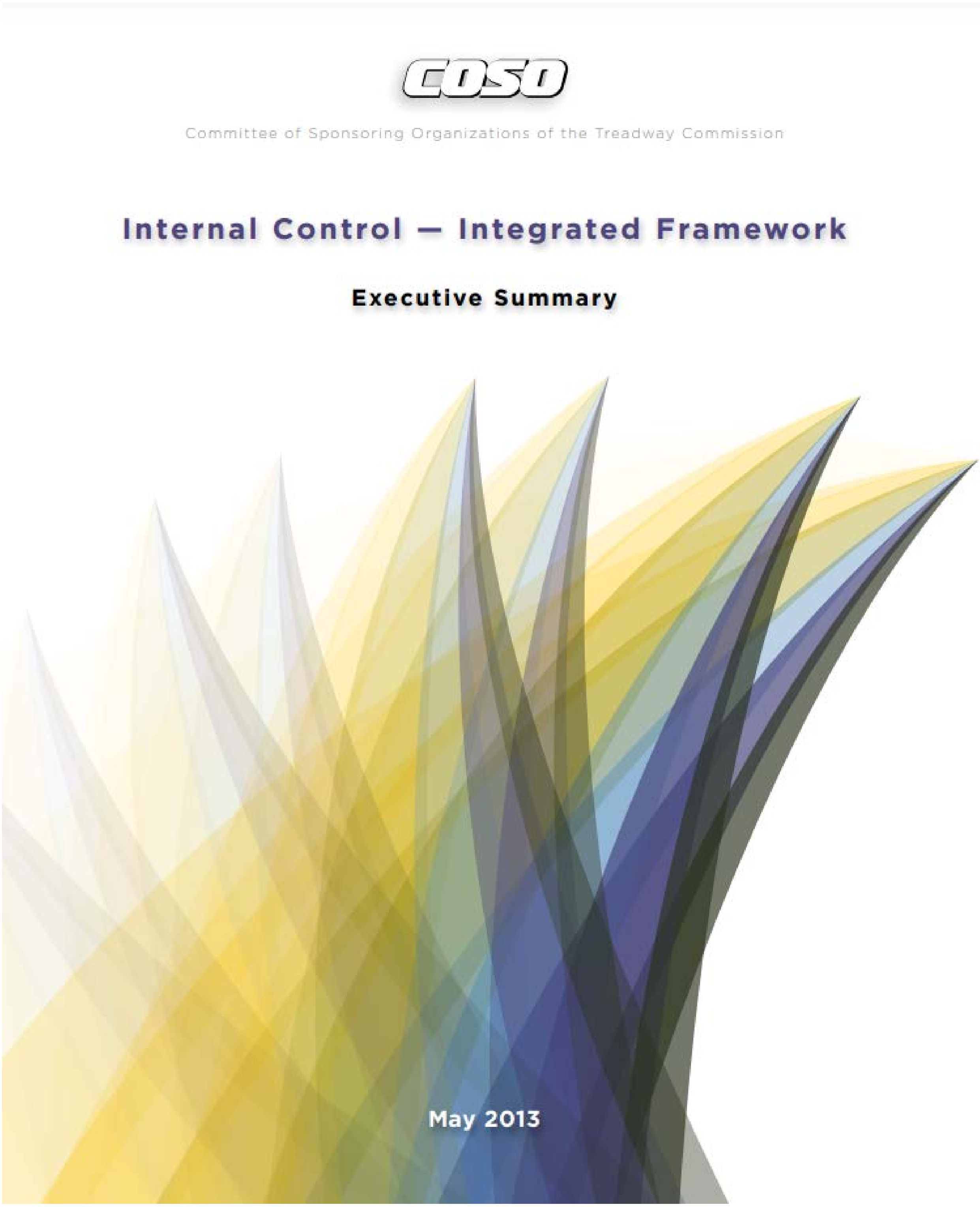
[1] https://www.coso.org/documents/990025p-executive-summary-final-may20.pdf

"Internal control is a process, effected by an entity's board of directors, management and other personnel, designed to provide reasonable assurance regarding the achievement of objective in the effectiveness and efficiency of operations, reliability of financial reporting, and compliance with applicable laws and regulations."

EXHIBIT D
COSO Internal Control –Integrated Framework
Executive Summary
Culbertson

https://www.coso.org/documents/990025p-executive-summary-final-may20.pdf



COSO

Committee of Sponsoring Organizations of the Treadway Commission

Internal Control — Integrated Framework

Executive Summary

May 2013

EXHIBIT D
COSO Internal Control –Integrated Framework
Executive Summary
Culbertson

Relationship of Objectives and Components

A direct relationship exists between *objectives*, which are what an entity strives to achieve, *components*, which represent what is required to achieve the objectives, and the *organizational structure* of the entity (the operating units, legal entities, and other). The relationship can be depicted in the form of a cube.

- The three categories of objectives—operations, reporting, and compliance—are represented by the columns.
- The five components are represented by the rows.
- An entity's organizational structure is represented by the third dimension.

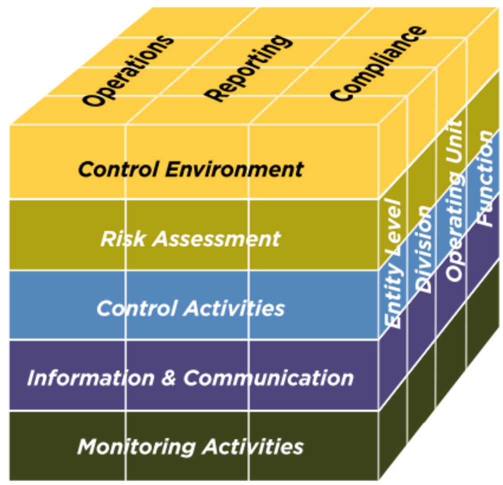


EXHIBIT E
Management Directive Standards for Internal Controls in Commonwealth Agencies 325.12 Amended

https://www.oa.pa.gov/Policies/md/Documents/325_12.pdf

MANAGEMENT DIRECTIVE

Commonwealth of Pennsylvania
Governor's Office

Subject: Standards for Internal Controls in Commonwealth Agencies	***Number:*** 325.12 Amended
Date: May 15, 2018	***By Direction of:*** Randy C. Albright, Secretary of the Budget

Contact Agency:
Office of the Budget, Office of Comptroller Operations, Bureau of Audits, Telephone 717.783.0114

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1. **PURPOSE.** To establish policy, responsibilities, and procedures for internal control systems within commonwealth agencies.

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   a. This directive applies to all departments, boards, commissions, and councils (hereinafter referred to as "agencies") under the Governor's jurisdiction.

   b. This directive applies to all aspects of an agency's operations, reporting, and compliance with applicable laws and regulations.

3. **OBJECTIVE.** To adopt and implement the internal control framework outlined in ***Standards for Internal Control in the Federal Government*** (Green Book) and ensure agencies use the components, principles, and attributes to design, implement, operate, and assess an effective internal control system.

MANAGEMENT DIRECTIVE

Commonwealth of Pennsylvania
Governor's Office

Subject: Standards for Internal Controls in Commonwealth Agencies	***Number:*** 325.12 Amended
Date: May 15, 2018	***By Direction of:*** Randy C. Albright, Secretary of the Budget
Contact Agency: Office of the Budget, Office of Comptroller Operations, Bureau of Audits, Telephone 717.783.0114	

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4. DEFINITIONS.

a. Component. One of five required elements of internal control: control environment; risk assessment; control activities; information and communication; and monitoring.

b. Deficiency. When the design, implementation, or operation of a control does not allow management or personnel, in the normal course of performing their assigned functions, to achieve control objectives and address related risks.

c. **Green Book.** The commonly used name for the *Standards for Internal Control in the Federal Government* issued by the United States Government Accountability Office. The Green Book provides managers criteria to design, implement, and operate an effective internal control system. The Green Book defines the standards of internal controls through components and principles of internal control and explains why they are integral to an entity's internal control system. Attributes are used to provide further explanation of the principles and documentation requirements for effective internal control.

d. **Internal Control.** A process effected by an agency's oversight body, management, and other personnel that provides reasonable assurance that the objectives of an entity are being achieved.

e. **Internal Control System.** A continuous built-in component of operations, effected by people, that provide reasonable assurance, not absolute assurance, that an agency's objectives will be achieved.

f. **Management.** Agency personnel who are directly responsible for the activities of a program or objective, including the design, implementation, and operating effectiveness of the related internal control system.

g. **Material Weakness.** A deficiency, or a combination of deficiencies, in internal control such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis.

h. **Oversight Body.** The designated members of an agency's senior management team responsible for overseeing management's design, implementation, and operation of the internal control system.

i. **Principles.** The 17 elements of an effective internal control system, that when adhered to, will support the effective design, implementation and operation of the five components.

j. **Service Organization.** A party external to commonwealth government that provides a service that is likely to be relevant to an agency's internal control.

k. **Significant Deficiency.** A deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

5. POLICY.

a. Each agency must design, implement, and operate, for all programs under its jurisdiction, an internal control system that incorporates the five components of internal control; follows the framework established by the Green Book; and documents the internal control responsibilities of the agency.

b. An assessment of the internal control system's adherence to the 5 components and 17 principles noted in the Green Book must be conducted and documented annually. See the Internal Control Assessment Template.

c. The Assurance Statement regarding the agency- and program-level effectiveness of the internal control system must be provided to the Office of the Budget by September 30, (for the fiscal year ending June 30, See the sample Annual Statement of Assurance.

d. The results of ongoing internal and external monitoring and evaluation of the agency internal control system must be documented. See the Monitoring Plan Guidance document.

e. Corrective action plans to address internal control system deficiencies must be documented and implemented timely.

f. The Office of the Budget shall provide for a technical review of the agency's annual internal control assessment and monitoring plan to ensure compliance with this directive.

6. RESPONSIBILITIES.

a. Agency Heads shall:

(1) Establish an oversight body to direct the assessment of internal controls.

(2) Identify the need for policies and procedures for internal control within the agency to ensure the effective design, implementation, and operation of internal controls.

(3) Provide for an annual assessment of internal control at the agency and program levels.

(4) Provide an annual statement of assurance regarding the effectiveness of the agency's internal controls.

(5) Provide for an annual internal and external monitoring plan.

(6) Annually, by September 30, submit the internal control assessment, the Annual Statement of Assurance on the effectiveness of the agency's internal controls, and the monitoring plan to the Office of the Budget, Office of Comptroller Operations, Bureau of Quality Assurance.

b. Agency Management shall:

(1) Develop and maintain effective internal controls.

(2) Continuously monitor and improve the effectiveness of internal controls associated with their operations, financial reporting, and compliance. Continuous monitoring, and other periodic evaluations, should provide the basis for the agency head's annual internal assessment of internal control.

(3) Identify any deficiencies in internal control based on internal and external information.

(4) Report any control deficiencies to the oversight body to determine the effect of each deficiency.

(5) Develop a corrective action plan for significant deficiencies and material weaknesses and monitor the progress to ensure timely and effective results.

(6) Follow the policy and procedures in Management Directive 325.13, Service Organization Controls when using service organizations that support agency processes.

c. **Agency Oversight Body** shall:

(1) Coordinate or perform evaluations of agency assessments, Office of the Budget technical review comments or reports, and service organization reports to enhance or maintain effective internal controls.

(2) Monitor corrective action initiatives to confirm corrective action has been implemented.

d. **Office of the Budget, Office of Comptroller Operations** shall:

(1) Develop guidance necessary for agencies to complete their annual internal assessment of internal control. See the Internal Control Assessment Template.

(2) Develop guidance necessary for agencies to implement an annual plan for ongoing monitoring. See the Monitoring Plan Guidance document.

7. **PROCEDURES.** All agencies must observe the following minimum procedural steps to ensure adequate management controls, accountability, and uniformity in creating and implementing a system of internal controls.

a. **Action by Agency Head.**

(1) Designates senior management to the oversight body.

(2) Coordinates or confers with the oversight body to administer management's design, implementation, and operation of the internal control system.

(3) Assigns agency management to develop and update the annual assessment of internal control and the internal and external monitoring plans.

b. **Action by Agency Management.**

(1) Identifies deficiencies in internal control using the following sources of information:

(a) Management knowledge gained from the daily operation of agency programs and systems.

(b) Management reviews conducted (i) expressly for assessing internal control, or (ii) for other purposes with an assessment of internal controls as a by-product of the review.

(c) Reports, including audits, inspections, reviews, investigations, or other products of the Department of the Auditor General, Office of Inspector General, Office of the Budget, and federal agencies.

(d) Program evaluations.

(e) Control self-assessments.

(f) Audits of financial statements, including information revealed in preparing the financial statements; the auditor's reports on the financial statements, internal control, and compliance with laws and regulations.

(g) Single audit reports.

(h) Reviews of financial systems, including service organization controls reports.

(2) Completes an annual internal control assessment by entering required information into the designated Online Assessment Tool. The Internal Control Assessment Template can be used as a guide.

(3) Identifies and reports any internal control deficiencies to the oversight body.

(4) Develops and implements a corrective action plan for any significant deficiencies and material weaknesses.

c. **Action by Office of the Budget, Office of Comptroller Operations, Bureau of Quality Assurance.** Provides guidance to agencies in establishing their monitoring plans. See the Monitoring Plan Guidance document.

d. **Action by Agency Head.**

(1) Evaluates internal control assessments and corrective action plans in conjunction with the oversight body to determine significant deficiencies and material weaknesses and prepare the agency internal control assessment.

(2) By September 30, submits the internal control assessment, the Annual Statement of Assurance on the effectiveness of the agency's internal controls and the monitoring plan to the Office of the Budget, Office of Comptroller Operations, Bureau of Quality Assurance.

e. **Action by Office of the Budget, Office of Comptroller Operations, Bureau of Quality Assurance.**

(1) Monitors the receipt of the agencies' assurance statements, the assessments of internal controls, and the monitoring plans.

(2) Performs a technical review of the internal assessment of internal control and the monitoring plan to ensure compliance with the requirements of this directive.

(3) Notifies the Commonwealth Audit Committee of significant deficiencies and material weaknesses.

(4) Reports to the Commonwealth Audit Committee at least semi-annually the progress of the agencies' corrective action plans.

(5) Notifies the Commonwealth Audit Committee of agencies that fail to provide the required assurance statement, the internal assessment, or a monitoring plan.

f. Action by Agency Head. Incorporates the Office of the Budget, Office of Comptroller Operations, Bureau of Quality Assurance best practice comments or recommendations into the agency monitoring plan and the assessment process.

g. Action by Commonwealth Audit Committee.

(1) Compels agency compliance with this directive.

(2) Assesses significant deficiencies and material weaknesses to determine the effect on enterprise wide risk.

(3) Recommends agencies obtain formal evaluations of internal control systems as appropriate or initiates control self-assessment in accordance with *Management Directive 325.11, Evaluating Agency Internal Controls and Financial Risk through Self-Assessment*.

h. Action by Office of the Budget, Office of Comptroller Operations, Bureau of Audits. Upon request of the Commonwealth Audit Committee, provides formal evaluations of agency internal control systems or facilitate a Control Self Assessments in accordance with *Management Directive 325.11, Evaluating Agency Internal Controls and Financial Risk through Self-Assessment*.

This directive replaces, in its entirety, *Management Directive 325.12, dated December 17, 2014.*

Columbia Gas of Pennsylvania

A NiSource Company

STANDARDS FOR CUSTOMER SERVICE LINES, METERS, AND SERVICE REGULATORS

(Plumber's Guide)

Revised: 06/01/2021

PREFACE

The information included in this booklet is intended as a guide for installation, inspection, and testing of plastic two-inches and under **customer service lines and meter setting installations**. This is only a guide, and may not include all applicable codes, regulations, policies and procedures, or revisions.

NOTE: The reader should be aware that the printed copies of this document may not be current and electronic copies of this document that can be viewed at the Columbia Gas Web Sites are the most current and accurate version.

NOTE: An asterisks (*) following a section title indicates that explanatory material and excerpts from relevant codes can be found in Appendix A, and is numbered to correspond with the applicable guide paragraphs.

Columbia Gas Standards

"Standards for Customer Service Lines, Meters, and Service Regulators" (Plumber's Guide); New Tap and Meter Process, Materials for Customer Service Lines, Standard Drawings for Meter Settings, Operator Qualification Card, and Plumber's Guide Revision Proposal Form are available for Pennsylvania at: www.columbiagaspa.com/

Q: How does a plumber or builder get a copy of the Plumber's Guide, Material Manual, and related information?

A: Launch your computer internet web browser, and:

For Pennsylvania

Type http://www.columbiagaspa.com/

Go to bottom of page, under heading **Partner with Us** then click:

- "Contractors and Plumbers"
- Right-side links:
  "Plumber Qualifications", scroll down to
  "Plumber's Guide",
  "Approved Materials Manual",
  or
- Body links

Q: How does a customer find a plumber who has met the federal guidelines to be Operator Qualified?

A: The list is posted on the Company's website, and is updated weekly. It is sorted by City and State.

Follow the steps above. There are links to the Operator Qualification lists.

DOT Part 192

The Code of Federal Regulations Title 49, Department of Transportation Part 192, "Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards" (available on the internet at: www.gpoaccess.gov/); Gas Company policies and procedures; and local codes shall be followed, and will be the basis for Gas Company inspection, testing, and/or approval when installing **service lines and meter settings**.

Fuel Gas Code

The National Fuel Gas Code (ANSI Z223.1/NFPA 54) shall be followed. It is a national standard, and will be the basis for Gas Company inspection, testing, and/or approval for **house lines and appliances**. The code can be purchased from:

- American Gas Association (AGA), (202) 824-7000, internet: www.aga.org; or
- Techstreet (techstreet.service@thomson.com)
  Phone: 800-699-9277 FAX: 734-913-3946 Int'l: 734-913-3939
  Mail Order: 777 E. Eisenhower Parkway, Ann Arbor, MI 48108

Other codes, such as the International Fuel Gas Code, may be enforced by local building code inspectors, and adherence to them for those inspectors may be required. The more stringent code must always be followed. When in doubt, contact the Gas Company and the Authority having jurisdiction to clarify before proceeding with the work.

Manufactured Homes Part 3280

The Code of Federal Regulations Title 24, Housing and Urban Development Part 3280, "Manufactured Home Construction and Safety Standards"; Gas Company policies and procedures; and local codes shall be followed and will be the basis for Gas Company inspection, testing, and/or approval of **Manufactured Homes**.

Phone Numbers

Gas Company

Emergency:

Pennsylvania - 888-460-4332

Service Inquiries (DirectLink):

Pennsylvania – 888-460-4332

New Business – 800-440-6111

Call Before You Dig (One Call)

National One Call – 811

Pennsylvania One Call – 800-242-1776

REVISIONS TO PREVIOUS EDITION

This guide replaces, in its entirety; the standard dated April 1, 2018.

Changes to the previous edition include:

Extensive wording changes and updates have been made to the manual. Please review the entire manual.

The major topics changed in this edition are:

- Section 2.5.1 – Part (h) has been updated to reflect acceptable date ranges for plastic pipe manufactured on or after March 6, 2015.
- Section 2.5.3 – Part (f) has been revised to replace the use for socket fusion for joining plastic pipe and plastic fittings with electrofusion.
- Section 2.5.4 – Part (a) replace socket fusion with electrofusion.
- Section 3.1.5 – Part (b) has been updated to prohibit PVC plastic pipe from being used as regulator vent line after June 12, 2021. Metallic vent line shall be used.
- APPENDIX A – Section A.2.3.4 – Part (a) has been revised to specify that butt fusion is not permitted for sizes less than 2".
- APPENDIX A – Section A.2.3.4 – Part (b) has been revised to state that socket fusion is no longer permitted to join plastic pipe to pipe or plastic pipe to fittings. Effective June 12, 2021.
- APPENDIX A – Section A.2.3.4 – Part (c) has been revised to state that electrofusion may be used to join plastic pipe of the same or dissimilar plastic designations.
- APPENDIX A – Section A.3.6.1 – Part has been revised to specify that the Gas Company shall approve high pressure meter settings.
- APPENDIX A – Section A.4.2.1 & A.4.3 has been revised to reflect new pressure testing requirements. New Durations requirements have been specified based on length.
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TABLE OF CONTENTS

NOTE: An asterisk (*) indicates explanatory information on the paragraph can be found in Appendix A.

APPENDICES

INDEX

PART 1 - GENERAL

1.1 SCOPE

(a) This manual, covering the installation, inspection, and testing of gas service lines, meter set assemblies, meters, and service regulators is published by Columbia Gas, herein referred to as the "Gas Company," for two purposes:

1. As a compilation of standards in the industry for ready reference for those persons and firms doing work of the nature described herein; and
2. To describe the inspection and testing of service lines which the Gas Company will require before establishing service.

(b) The standards of this manual pertain to all customer service line installations which utilize plastic pipe sizes two inches and smaller. Consult the Gas Company for service line installations that use steel pipe or pipe sizes greater than two inches.

(c) Consult the National Fuel Gas Code (ANSI 223.1, NFPA 54) for information covering the installation, inspection, and testing of house lines, appliances, and venting.

(d) The provisions in this manual are subject to change and are not intended to be all-inclusive. Local codes, ordinances, and governmental regulations will govern when they are more stringent than the requirements contained herein. When in doubt as to the proper procedure, consult your Gas Company before proceeding with the work.

(e) For other installation information:

1. GPTC Guide for Gas Transmission and Distribution Piping Systems.
2. Title 24, Code of Federal Regulations, Part 3280, Manufactured Home Standards.
3. NFPA 501A Installation of Mobile Homes Including Mobile Home Park Requirements.
4. Title 49, Code of Federal Regulations, Part 192 – Transportation of Natural Gas by Pipeline.

(f) The Gas Company will not assume responsibility for any defective material or faulty workmanship in the installation or repair of the customer's house lines, appliances, appliance connections, appliance venting, or for any loss or damage arising from such defective material or faulty workmanship.

PA: The Gas Company will also not assume responsibility for any defective material or faulty workmanship in the installation or repair of the customer's service line or meter setting.

(g) The nature and extent of the Gas Company's inspection and testing is set forth in Part IV, and nothing herein shall operate to enlarge or modify the Gas Company's responsibility for this inspection and testing.

1.2 CUSTOMER ADVISORY SERVICE

(a) To assist customers in obtaining maximum benefits at the lowest cost from the use of gas, the Gas Company maintains a staff of experienced personnel whose services are available.

(b) The Gas Company will advise on gas applications, piping arrangements and furnish general information on the use and economics of natural gas for residential, commercial and industrial customers.

(c) The Gas Company will provide advice and guidance to customers, plumbers, and other persons involved with the installation of customer service and house lines consistent with the following guidelines on sizing, materials, location, and installation. It is the ultimate responsibility of such customers, plumbers, and other persons to take the necessary action to make proper installations that are consistent with the objectives of the guidelines.

(d) The Gas Company will furnish information regarding local taxes, utilities, transportation, and the availability of labor supply on potential commercial and industrial sites.

1.3 REQUEST FOR GAS SERVICE

Request for service should be made by the customer or customer's representative. Information on how to make this request may be obtained from the Gas Company.

1.3.1 Information Required

The following information is needed when gas service is requested:

(a) Name;

(b) Exact address and description of the location at which service is requested;

(c) Type of occupancy, such as residence (single or multiple), commercial, church, school, industrial, municipal, or other public use;

(d) Contemplated use of gas, such as space heating, air conditioning, water heating, cooking, incineration, clothes drying, grilling, commercial and/or industrial processes;

(e) Gas pressure required; and

(f) Estimated date gas service will be required.

1.3.2 Arrangements for Establishing Gas Service*

(a) The Gas Company will determine if a main extension is required, advise the customer or customer's representative of the terms and condition for the extension and explain deposit requirements, if necessary.

(b) The customer or customer's representative will make arrangements for the installation, inspection, and testing of the customer service line in accordance with the standards and information set forth in this manual, and house lines in accordance with the National Fuel Gas Code.

(c) Prior to calling for the Gas Company to establish service, builder/contractor will install the customer house line, the customer service line and meter setting, and attach the appropriate Installation Card which attests that the person making the installation is qualified by "DOT Operator Qualification" (OQ Card, Form C-3363) when performing an OQ covered task.

PA: Certain locations, customer service line and meter setting are installed by the Gas Company. In these location the builder/contractor does not perform an OQ covered task and does not require an OQ card.

House Lines must meet the following conditions:

1. There must be at least one appliance drop with a plugged appliance valve.
2. House line piping connecting to the meter setting shall:
   a. be a minimum of Schedule 40 steel pipe, (csst no longer permitted)
   b. be securely anchored inside the structure to support the piping and meter setting
   c. be sealed to rain and insect resistant (wall sleeve)
   d. the distance between the meter and any obstruction to the sides, rear, top, or bottom should be a minimum of six (6) inches but in no case shall the meter touch the ground. Distance between the meter and any obstruction from the front should be a minimum of 36 inches
   e. extend through the outside wall:
      i. 4-6 inches for piping smaller than 2 inches,
      ii. 6-8 inches for piping 2 inches and larger for threaded connection, or

iii. 10 inches for piping 2 inches and larger for welded connection.

f. For Mobile homes follow section 3.5.1 of this guide

3. On multiple meter installations, each house line stub shall be identified with a tag of approved means to designate the apartment or the part of the building it supplies (see 3.3.3, 3.3.8, 3.5.1, 4.2.4, and A.1.3.2).

(d) Call the Gas Company requesting visual inspection, pressure test, and meter installation after the following conditions have been met:

1. Service Line, house lines, meter setting, and appliances, when applicable, are ready for inspections and tests.
2. Where required, documentation of an Approval for Natural Gas Service from Building Code Officials
3. Access to all parts of the building with gas piping and/or appliances will be available to Gas Company personnel.

1.4 AS LONG AS THE CONDITIONS ABOVE ARE MET, GAS COMPANY PERSONNEL WILL TEST AND INSPECT THE CUSTOMER SERVICE LINE TO THE METER SETTING. BASED ON THE INSPECTION, TEST, AND INSTALLATION CARD GAS SERVICE WILL BE ESTABLISHED TO THE OUTLET METER VALVE IF ALL ARE ACCEPTABLE. CUSTOMER CHARGES

The first inspection and/or test (see PART 4 - INSPECTION, TESTING) shall be without charge. In the event the lines do not pass such inspection and/or test, or if other unsatisfactory conditions result in a disapproval, the necessary correction(s) shall be made at the owner's expense and the line involved shall again be inspected and tested. Additional inspection(s) and/or test(s) shall be subject to a charge.

1.5 OWNERSHIP AND RESPONSIBILITY

(a) The materials, installation, and location of the customer service line and meter setting shall be subject to the standards contained herein.

(b) The Gas Company retains ownership of the meter and service regulator(s). The Gas Company also retains ownership of the service line and meter setting.

PA: Certain locations, the customer retains ownership of the service line and meter setting.

(c) The customer shall be responsible for house lines at their own expense.

PA: Certain locations, the customer shall also be responsible for:

1. The installation of new customer service line and meter setting(s),
2. Relocation of the customer service line and meter setting at the customer's request,
3. Customer service line and meter setting upgrades due to load changes,
4. These lines and settings shall be subject to inspection and test as provided herein, but the Gas Company assumes no responsibility for their condition.

(d) The Gas Company is responsible for the repair/replacement of hazardous leakage on service lines. Only the Gas Company or its agents are authorized to complete repairs and/or replacements.

PA: The customer shall also be responsible for the repair/replacement of hazardous leakage on customer-owned service lines.

1.6 DEFINITIONS

Abandoned – A service line is classified as abandoned when it has been physically separated from the main and plugged or sealed.

Accessible – Availability in case of emergency, repair, or inspection may require the removal of a panel or door.

Accessible, Readily – Immediate availability in case of emergency, repair, or inspection.

Anode – The electrode of an electrochemical cell at which corrosion occurs. Required to protect a buried metallic pipeline from corrosion (see Cathodic Protection, 2.3.3, 2.3.5, and 2.6.4).

Approved – 1) Acceptable to the authority having jurisdiction. 2) See approved materials.

Approved Materials – Materials submitted for qualification and found to be satisfactory for the use intended will be added to the list of approved items. In addition, approved materials that do not continue to meet quality standards of the Gas Company will, after investigation, be deleted from the listing of approved items. Approved materials for the work described herein are listed by manufacturer's name and designation in the "Approved Materials for Customer Owned Service Lines" booklet that is available from the Gas Company. These listings are not arbitrarily maintained and are subject to revision by the Gas Company as the need arises. While it is the policy of the Gas Company to reissue these listings no more than once each calendar year, more frequent revisions may be issued if appropriate.

Authority Having Jurisdiction – Fire Chief, Local Code Official, Representative of the Gas Company, or others who are responsible for approving equipment, materials, installation, or procedures. Local codes, ordinances, and governmental regulations will govern when they are more stringent than the requirements contained herein. When in doubt as to the proper procedure, consult your Gas Company and other authorities before proceeding with the work.

Cathodic Protection – The prevention of corrosion of a pipeline by causing it to act as the cathode rather than as the anode (see anode) of an electrochemical cell.

Corrosion – The reaction of metallic pipeline to air, water, and other environmental factors causing the loss of metal and integrity. The most familiar example is rust.

Customer – the person, firm or corporation for whose account and use gas service is established and delivered.

House Lines – the piping and fittings from the outlet of the meter or the connection to the company service line if there is no meter set assembly, to the appliance shutoff valve.

Main (line) – distribution line that serves as a common source of supply for more than one service line.

MAOP (Maximum Allowable Operating Pressure) – Maximum pressure a pipeline or segment of a pipeline may be operated.

Meter – measures the transfer of gas from an operator to a customer.

Meter Set Assembly (Setting, Meter Setting) – the piping, fittings, meter valve, meter and when required the service regulator, installed to connect the customer service line to the house lines.

Operator – a "person" who engages in the transportation of gas.

Operator Qualification Card (Form C-3363) – documents qualification under federal regulations, required for installation, replacement or repair of service lines and/or meter settings.

Plastic, High Density – Black gas piping, tubing, and fittings conforming to ASTM D 2513 designations of PE3406, PE3408, or PE4710 (bimodal).

Plastic, Medium Density – Yellow, orange, or tan/pink (Aldyl A) gas piping, tubing, and fittings conforming to ASTM D 2513 designations of PE2306, PE2406, or PE2708.

Purging is the process of displacing air with natural gas from a new or repaired pipeline OR displacing natural gas with air when repairing or abandoning a pipeline.

Qualified – capable of and skilled to perform a task based on appropriate training and/or experience.

Regulator, High Pressure – owned by the Gas Company and installed to reduce pressure to 99 psig or less so that it can be handled by a service regulator.

Regulator, Service – owned by the Gas Company and installed to reduce the service line gas pressure to house line delivery pressure.

Retroactivity – Unless otherwise stated, the provisions of this standard shall not be applied retroactively to existing system(s) that were in compliance with the provisions of the codes and standards in effect at the time of installation. Changes to the existing system(s) require installation in accordance with current codes and standards.

Service Line – a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Service Line, Company – the piping that extends from the Gas Company main to a curb valve or in the absence of a curb valve to the customer property line.

Service Line, Customer – the piping that extends from the end of the company service line at the property line to the inlet of the meter set assembly.

Service Line Pressure, Low – the pressure is substantially the same as delivered to the appliances, a service regulator is not required, normally 10" WC to 14" WC.

Service Line Pressure, Intermediate – above low pressure, requires a service regulator. Normally 2 psig to 10 psig but may drop to 1 psig during periods of full demand.

Service Line Pressure, Medium – higher than intermediate pressure, requires a service regulator. Normally 10 psig to 60 psig but may drop to 2 psig during periods of full demand.

Service Line Pressure, High – maximum allowable pressure exceeds 60 psig. High-density polyethylene plastic (HDPE – black PE-3408) may be installed to a maximum pressure of 99 psig.

Shall – Indicates a mandatory requirement.

Valve, Curb* - [see A.2.5.3 (a)] a valve that, when required, isolates the customer and company service lines.

Valve, Excess Flow* - [see A.2.5.3 (a)] a valve that, when required, reduces or stops the flow of gas when a rapid loss of pressure is detected in a gas line.

Valve, House Line – Gas shut off valve installed after the outlet of the meter usually before regulator at the manifold for elevated pressure house line piping.

Valve, Meter – Gas shut off valve installed before the regulator and meter, also called a Service Line Valve or Inlet Meter Valve.

Valve, Outlet Meter – Gas shut off valve installed after the outlet of the meter usually on the meter setting outlet.

PART 2 - CUSTOMER SERVICE LINES

2.1 GENERAL REQUIREMENTS GOVERNING CUSTOMER SERVICE LINES

2.1.1 One service line to one building.

Only one service line will be provided to single units, doubles (duplexes), apartments, condominiums, and strip units (see Sketch No. 1).

Exception: *Local code jurisdictions may require house lines to pass into or through only the unit served and therefore require separate service and/ or houses lines to each unit. Check local codes.*

2.1.2 Existing Service Lines

Where a service line exists, a separate service line shall not be installed to a garage, workshop, or other building(s) on a single property.

2.1.3 Property Lines

Customer service lines shall not cross or enter more than one customer property line.

2.1.4 Split Service Lines

(a) Customer service lines shall not be extended or split without Gas Company approval.

(b) If approved, split customer service lines shall not serve more than two adjacent or adjoining meters and shall be entirely located on a single property.

2.1.5 Service Classifications

(a) A service line and premise status is classified as **New Service Line (NSL)** during the time interval between the service line installation and execution of the New Set Meter Order.

(b) A service line, meter and premise status is classified as **inactive** when the meter valve and/or curb valve is **turned off and the meter is not removed** from the meter set assembly. A manifold setting must continue to have at least one inactive meter for the master service line (PSID) to be classified as inactive.

(c) A service line and premise status is classified as **idle** when the meter of a single meter set assembly or the last remaining **meter** on a manifold setting **has been removed**.

(d) A service line is classified as **abandoned** when it has been **physically separated from the main** and plugged or sealed.

2.2 LOCATION OF SERVICE

2.2.1 Service line routing

(a) In selecting the location of the service line, consideration shall be given to the best location for the connection to the main and the meter set assembly (see Sketch No. 2).

(b) The service line should be installed in a continuous straight line perpendicular to the main to the point at which connection is made to the riser or where the piping enters the outer masonry wall of a building below grade (see Sketch No. 2). A short 90º offset at the side(s) of the building nearest the mainline may be permitted.

2.2.2 Service entrance

The service line should enter the building wall above grade.

(a) **Above grade -** Where the customer service line is to enter through the outer wall of the building above grade, a flexible steel casing or rigid steel encased non-corrosive riser shall be used so that the transition from plastic to steel may be above ground (see Sketch No. 6).

(b) **Below grade**

1. When a plastic service line enters through the outer wall of the building below grade it shall be encased with steel pipe through the foundation wall and the transition from plastic to steel shall be made inside using an approved adapter fitting as used for insert renewal of service lines (see 3.2.1(g) and Sketches 5-8 & 12).
2. As an alternate below ground service entrance, a rigid, straight, prefabricated non-corrosive type cased gas line may be used as a combination casing and transition fitting. The rigid portion is fixed in the wall so that the plastic to steel transition (or ground level marking) is through the wall on the basement side (see Sketch No. 6).

(c) **Masonry wall -** A service line installed through the outer masonry wall of a building, either above or below grade, shall be encased in a sealed and approved steel or plastic sleeve.

1. Galvanized steel sleeves are not permitted below grade.
2. The opening between the sleeve and the outer masonry wall shall be filled with grout or sealed by the use of service entry flanges (see Sketch No. 7 & Sketch No. 8).

2.2.3 Installation of service lines under buildings*

(a) Service lines should not be installed under buildings unless it is unavoidable.

(b) Where an underground service line is installed under a building:

1. It shall be encased in a gas tight conduit capable of withstanding any superimposed stresses, required pressure test, protected from corrosion; and
2. The conduit and the service line shall, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and
3. The space between the conduit and the service line shall be sealed to prevent gas leakage into the building. If the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting (see Sketch No. 12).
4. An existing steel line shall pass a test at operating pressure for three minutes to ensure it is gas tight prior to use as the conduit.
5. Metal conduit and/or piping must be protected from corrosion.

2.3 MATERIALS

Only materials approved by the Gas Company shall be used. A list of approved materials is found in the Gas Company listing entitled "Materials for Customer Service Lines" available on the internet at or http://www.columbiagaspa.com/ for Pennsylvania.

2.3.1 Plastic Pipe and Tubing

(a) Plastic pipe and tubing shall conform to ASTM D 2513, Specifications for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings.

(b) Medium density plastic pipe and fittings shall not be used to repair high density plastic service lines.

(c) A list of approved manufacturers of pipe is found in the Gas Company listing entitled "Materials for Customer Service Lines."

2.3.2 Steel Service Pipe*

Where steel pipe is to be used for installing underground customer service lines, consult the Gas Company for material and installation requirements. Steel customer service line installations shall not be approved unless designated for steel by the Gas Company Engineering Department. All welding shall be done by a qualified person (see A.2.3.2).

2.3.3 Mechanical Fittings*

(a) Mechanical fittings must be approved and installed in accordance with manufacturer's installation instructions. A list of Gas Company approved fittings is found in the "Materials for Customer Service Lines."

(b) Metal fittings underground shall be cathodically protected and coated and/or wrapped.

Note: *To provide cathodic protection, isolated metal fittings underground shall have an anode (1 lb. minimum) attached. Metal fittings underground attached to metal piping shall have an anode (3 lb. minimum) attached [see 2.6.4 and 4.1.3(d)].*

2.3.4 Plastic Fusion Fittings*

Approved plastic pipe fittings designed for making heat fusion joints may be used to connect lengths of plastic pipe. Consult the Gas Company before joining dissimilar materials. Plastic pipe fittings shall conform to ASTM D 2513 and 2683. Persons making fusion joints shall have a valid "Fusion Qualification Card" from an approved agency.

2.3.5 Screw Fittings

(a) Screw fittings shall be used above ground only and shall be black or galvanized malleable iron, standard weight of banded type. Unions are permitted, only above ground, when required.

Exception: *A "mechanical/adapter fitting", specifically designed and approved to mechanically join plastic pipe to a screw end curb valve, may be used underground but shall be coated and/or wrapped and cathodically protected. Metal fittings underground attached to metal piping shall have an anode (3 lb. minimum) attached.*

Note: *Screw fittings shall comply with the requirements of ANSI B16.3—American Standard for Malleable Iron Screwed Fittings and ANSI B2.1—American National Standard for Pipe Threads (except dryseal).*

(b) All thread nipples, and cast iron fittings shall not be permitted.

(c) Threaded joints shall have sealant approved for natural gas applied according to the manufacturer's instructions.

2.3.6 Risers

(a) **Outside riser, outside meter -** An approved flexible steel casing or rigid non-corrosive steel encased plastic service line riser shall be used with plastic service lines (see Sketch No. 3 & Sketch No. 4). A wall mounting plate or bracket fastened to the riser and building wall shall be used to firm the installation. Where it is not practical to attach the bracket to the building wall, a heavy gauge steel stake, or equivalent, firmly embedded parallel and immediately adjacent to the foundation wall shall be used as a support (see Sketch No. 9 & Sketch No. 10).

(b) **Risers in Concrete or Asphalt -** Where a riser passes through a walk, patio, or driveway, it shall be installed through a sleeve or other means of providing a space between the riser and the walk, patio, or driveway. The space between the sleeve and riser shall be filled with gravel (see Sketch No. 5).

2.3.7 Meter Valves

Meter valves approved by the Gas Company shall be used.

(a) Valves, nominal pipe sizes ¾, 1, and 1-¼ inches, shall be of the insulating union-type, having lock wing head or equivalent, and tamperproof core. These meter valves shall be provided with a drilled and tapped 1/8-inch port on the inlet side of the valve body for test purposes. An Allen head plug shall be used to close the port.

(b) Where the inlet piping to a single meter set assembly is 2 inches nominal pipe size or greater, an insulating union, flange or coupling shall be installed in the setting above ground and downstream of the meter valve The insulator is preferred downstream of the regulator (if one exists) to electrically isolate the service line from the house lines. In addition, a test tee shall be installed above ground upstream of the meter valve (see Sketch No. 3).

2.4 SERVICE LINE SIZING*

Refer to APPENDIX C – Service Line Sizing.

In determining the size of service lines to be used in designing a gas piping system, <u>ALL SIX</u> of the items of this section (2.4.1 – 2.4.6) shall be considered.

2.4.1 Pipe Material

Plastic pipe sizing tables are in Appendix C. Contact the Gas Company for information on the use of steel pipe.

2.4.2 Available Service Line Pressure

(a) **Low Pressure Service Lines -** Low pressure customer service lines shall <u>not be less than 1 inch CTS</u>. The line shall be sized according to **Appendix C, Table 1.**

(b) **Intermediate Pressure Service Lines -** Intermediate pressure customer service lines shall <u>not be less than 3/4 inch CTS</u> when installed on systems to operate at 1 psig minimum pressure. The line shall be sized according to **Appendix C, Table 2.**

Exception: *On piping systems specifically designated by the Gas Company Engineering Department to operate at 2 psig minimum pressure, ½" CTS (5/8) may be used (Table 3).*

(c) **Medium Pressure Service Line -** Medium pressure customer service lines shall <u>not be less than 1/2 inch CTS</u>. The line shall be sized according to **Appendix C, Table 3**.

(d) **High Pressure Service Lines -** High-density polyethylene plastic (HDPE – black PE-3408) may be installed to a maximum pressure of 99 psig. The line shall be sized according to **Appendix C, Table 4**. Consult the Gas Company for sizing, material information, and installation practices for all other high-pressure service lines.

2.4.3 Pressure Drop

Contact the Gas Company for allowable pressure drops from the main to the meter other than specified by the applicable table in Appendix C.

2.4.4 Specific gravity and Heating Value of the gas

Columbia distributes **Natural Gas** with approximately: Specific Gravity of **0.6** and a Heating Value of **1000 Btu**/cubic foot.

2.4.5 Length of Piping

In sizing the customer service line, the entire service line (company service plus the customer service line) shall be treated as a unit.

2.4.6 Determining the Load

Gas demand in cubic feet per hour is determined by:

(a) **Residential** – input of space heater, furnaces, generators, and domestic water heating equipment. When the input rate of other appliance(s) such as a pool heater or air conditioner is more than the furnace, the total of the greater should be used. In the absence of central heating equipment, load requirements shall be determined from the total input requirements for all appliances.

(b) **Commercial** – input of all connected appliances.

(c)

2.5 INSTALLATION

2.5.1 General

(a) The maximum allowable operating pressure of plastic pipe for service lines is limited to: 60 psig for medium-density (yellow PE-2406), and 99 psig for high-density (black PE-3408).

(b) Plastic pipe above grade is prohibited except that which may terminate aboveground in an approved riser or installed with an approved wall head adapter in the basement.

(c) The Gas Company shall inspect the customer service line before backfilling any excavation(s), in accordance with the requirements in PART 4 - INSPECTION, TESTING of this manual.

(d) Solvents, pipe thread compound and lubricants, except those specifically deemed safe for use with plastic materials, shall not be allowed to contact the plastic. Consult manufacturers' recommendations.

(e) Plastic pipe shall not be installed in vaults or other below grade enclosures, unless it is completely encased in a gas tight metal conduit and metal fittings having adequate corrosion protection.

(f) Plastic pipe shall not be damaged. Gouges, grooves, kinks, and/or buckles shall be removed by cutting the damaged portion as a cylinder. Plastic pipe with wall thickness damage of 10% or greater shall not be used.

(g) Plastic pipe shall be protected from fire and heat. Exposure to sunlight shall be minimized. Plastic pipe that has been exposed to excessive sunlight will discolor and show craze marks and shall not be used.

(h) Plastic pipe shall not be used if it is older than the "Maximum Interval from Date of Manufacture" in the table below.

Maximum Allowable Outdoor Storage for Plastic Pipe

<table>
<tr><th rowspan="2">Material Designation</th><th rowspan="2">Color</th><th colspan="2">Maximum Interval from Date of Manufacturer</th></tr>
<tr><th>Date on pipe is March 6, 2015 or later</th><th>Date on pipe is prior to March 6, 2015</th></tr>
<tr><td>PE 2406/2708</td><td>Yellow</td><td>3 years</td><td rowspan="2">2 years</td></tr>
<tr><td>PE 3408/4710</td><td>Black with yellow stripes</td><td>10 years</td></tr>
</table>

(i) Plastic pipe shall be installed to minimized shear and tensile stresses from construction, back fill, and external loading. It shall be laid on undisturbed or well-compacted soil and may not be supported by blocking.

(j) Plastic pipe shall be provided sufficient slack for thermal expansion and contraction.

2.5.2 Trenching

(a) A plastic service line shall be laid on undisturbed or well-compacted soil not less than 6" from any other underground structure.

(b) Plastic service lines shall be laid at sufficient depth to provide a minimum of 18 inches of cover over the pipe.

(c) When the service line is in a trench with other utility services a minimum separation of 12 inches horizontally shall be provided.

(d) There shall be at least six inches of clearance where it is necessary for other utility services to cross either over or under the service line. Where possible, there should be a minimum one-foot separation with all electric carrier conductors.

(e) It shall not be run through septic tanks and/or leaching beds.

2.5.3 Joining Pipe*

(a) It is preferable to install the plastic service line as one continuous length of pipe between the curb valve and/or excess flow valve at the property line and the riser or joint of connection to coated steel pipe at the building.

(b) Where it is necessary to use more than one length of plastic pipe in the customer service line, the lengths shall be joined by either an approved mechanical fitting or heat fusion joint. When a mechanical fitting is used it must be installed in accordance with the manufacturer's installation instructions.

(c) When there is an existing curb valve, connections shall be made by a DOT Operator Qualified person(s) installing the service line.

(d) When the service line is installed prior to the main line tap installation, the Gas Company personnel will test and connect the service line if:

   1. the meter setting and service line are ready for inspection and test, and
   2. the Operator Qualification Card (Form C-3363) is attached to the meter setting.

(e) Metal fittings underground shall be cathodically protected and coated and/or wrapped.

(f) The procedure and equipment recommended by the manufacturer of the approved plastic pipe for making heat-fusion joints shall be used. Electrofusion of plastic fittings may be used on all sizes. When fusing sizes 2 inches and larger, butt fusion is permitted.

(g) Direct application of heat with a torch or other open flame to the plastic pipe is prohibited.

(h) Persons making plastic pipe joints must be qualified to make that type of joint. As proof of qualification, the person making any joint on plastic pipe must complete and attach to the meter setting an Operator Qualification Card (Form C-3363). The Gas Company representative can supply information on obtaining qualification, the applicable cards, and the procedures to follow on the job. This information is also available on the internet at http://www.columbiagaspa.com/ for Pennsylvania.

Note: *Joints in service lines not exposed for visual inspection or without a completed Operator Qualification Card shall not be approved.*

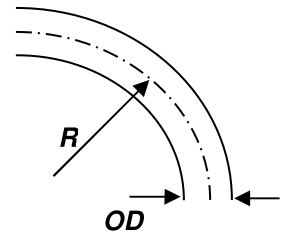
2.5.4 Bends

Changes in direction of plastic piping may be made with bends or elbows under the following limitations:

(a) Follow the pipe manufacturer's recommendation for the minimum bending radii. The following minimum bending radii will satisfy most recommendations.

Minimum Bending Radii (R)

Size	125 x OD*	25 x OD**
½″ CTS	7′	1.5′
1″ CTS	12′	2.5′
1 ¼ IPS	18′	3.5′
2″ IPS	25′	5.0′



*125 x OD = outside diameter for service lines **containing** fusion joints (butt, electrofusion, and saddle) or fittings within the bend radius.

25 x OD = outside diameter for service lines **without fusion joints or fittings within the bend radius.

(b) The bends shall be free of damage.

(c) Changes in direction that cannot be made in accordance with (a) above shall be made with elbow type fittings.

2.5.5 Tracer Wire

(a) A Gas Company-approved tracer wire shall be installed with all non-cased plastic service lines to facilitate pipe locating. For direct burial installations, the tracer wire shall be a minimum AWG #12 and should have a yellow jacket. For Directional Boring installations, the tracer wire should be a minimum AWG #12 for reinforced copper-cladded wire, and a minimum AWG #8 for solid copper wire.

(b) The wire shall be accessible so connection can be made to the locator transmitter (see Sketch No. 11) by bringing the wire up along the outside of the curb box and riser.

(c) The wire shall not be wrapped around the pipe and contact with the pipe should be minimized.

(d) Where plastic service lines are encased in metallic conduit, one of the two following methods shall be used to provide a means for locating the plastic pipeline.

1. Insert tracer wire with the plastic pipe into the metallic conduit if there is ample space within the conduit to avoid damage to the tracer wire or its protective coating.
2. Insert plastic pipe without the tracer wire into the metallic conduit. Locations where the remaining conduit has been separated shall be bonded across the cut sections to maintain continuity for locating purposes. In no case shall the bond wire be attached to, or allowed to come in contact with, in-service metallic piping or nonmetallic piping's tracer wire. Tracer wire shall be attached to the ends of the metallic conduit and brought up along the outside of the curb box and riser.

2.5.6 Note: Tracer wire shall be installed on a plastic service during riser replacement if not already present. Backfilling

(a) The Gas Company shall visually inspect the customer service line before backfilling any excavation(s) in accordance with the requirements in PART 4 - INSPECTION, TESTING of this manual.

(b) Backfilling shall be performed in a manner to provide firm support around the piping.

(c) The backfill shall be free of large rocks, building materials, etc. that might cause damage to the plastic pipe. Small-excavated rocks may be returned to the trench, but shall be prevented from contacting the pipe by earth padding of not less than six (6) inches above the pipe.

(d) No heavy equipment shall be run over the customer service line or trench immediately after it has been back filled.

(e) Where flooding of trench is done to consolidate the backfill, care shall be taken to see that the plastic pipe is not floated from its firm bearing on the bottom of the trench.

2.6 INSERT RENEWAL OF EXISTING CUSTOMER SERVICE LINES

Additional requirements for insert renewal of existing customer service lines.

2.6.1 Material

Only materials approved by the Gas Company shall be used in the plastic relining of the customer service line.

2.6.2 Sizing

(a) The size of the plastic piping used as an insert to renew customer service lines shall be based on Appendix C Sizing Tables No. 1, 2, 3, or 4.

(b) Plastic pipe of 1/2 inch CTS (5/8 inch OD) size may only be inserted into existing 3/4 inch or 1 inch IPS service lines that operate at greater than 10 psig pressure (see exception below).

(c) The insertion of 1/2 inch CTS through 1 1/4 inch or larger pipe is discouraged because of the possibility of water in the casing freezing and squeezing-off the plastic pipe.

Exception: *On piping systems specifically designated by the Gas Company Engineering Department to operate at 2 psig minimum pressure, 1/2 inch CTS (5/8 inch OD) may be used (Appendix C, Table 3).*

2.6.3 Installation

(a) The casing pipe shall be reamed and cleaned to the extent necessary to remove any sharp edges, projections, or abrasive material that could damage the plastic during or after insertion.

(b) Plastic pipe shall not be inserted in an old service line (casing) that does not have at least 12 inches of cover in private property and at least 18 inches of cover in streets and roads.

(c) The plastic shall be inserted into the casing pipe in such manner so as to protect the plastic during the installation. The leading end of the plastic shall be closed before insertion. Care shall be taken to prevent the plastic from bearing on the end of the casing.

(d) That portion of the plastic service line piping not encased shall be continuously supported to prevent shearing and a plastic pipe shim shall be installed where it enters and leaves the casing.

(e) The end of the casing pipe nearest curb stop shall be sealed or taped to prevent migrating gas from entering the structure.

(f) In cases where the meter is located in the basement and the service line enters the wall below grade, the plastic insert shall be connected to the meter riser using an adapter fitting for plastic insert renewal. (See Sketch No. 6.)

1. The steel casing pipe entering through the wall may be used as the required sleeving provided that it is good condition and firmly anchored in the wall. The opening between the casing pipe and wall shall be filled with grout or sealed by the use of a service entry flange (See Sketch No. 7).
2. Exposure of plastic within the building being served is prohibited.
3. The steel casing pipe shall be exposed, cut, and sealed at 12 inches beyond the exterior wall (See Sketches 5 & 6). It shall be sealed to prevent migrating gas from entering the structure and be vented when installed under pavement.

(g) In cases where the meter set assembly or riser is located outside of the building being served, the riser shall be replaced with a flexible steel casing type or rigid non-corrosive steel encased type (see 2.3.6).

(h) When plastic pipe is inserted through an old steel service line tracer wire shall be attached at the cut section(s) of remaining pipe to maintain electrical continuity

2.6.4 Anode Installation.

(a) To provide cathodic protection isolated underground metallic fittings with plastic pipe underground shall have an anode (1 lb. minimum) attached.

(b) Underground metallic fittings attached to metal piping and/or fittings shall have an anode (3 lb. minimum) attached.

(c) When practical the anode lead wire should be tied around the pipe prior to attachment to prevent pullout.

(d) The anode shall be placed so the lead wire is never lower than the rest of the anode. The anode lead wire shall be attached at or near the top of the pipe or fitting.

(e) The preferred attachment is a thermite weld, but fitting crimp connections are acceptable when provided. Approved clamp connections are permitted when the fitting does not have a crimp connection.

(f) The anode shall be deeper in the ground than the pipeline.

(g) Separation between the pipe and magnesium anodes may be reduced to 2 feet. Separation between the pipe and 1 lb. zinc anodes may be reduced to 1 foot.

PART 3 - METER SETTINGS

3.1 GENERAL

3.1.1 Meter

(a) The Gas Company will furnish and connect a meter for each customer.

(b) The Gas Company reserves the right to determine the size and type of meter to be installed.

(c) The meter remains the property of the Gas Company.

3.1.2 Meter Valves and/or Bars

Meter valves (see 2.3.7) and when applicable, meter bars shall be approved by the Gas Company.

3.1.3 Meter Settings

(a) When applicable, only prefabricated meter setting assemblies approved by the Gas Company shall be used.

(b) When applicable, Gas Company meter setting "standard drawings" (e.g., Plumber's Drawings) shall be followed. Written permission is required for deviation from the standard drawings.

3.1.4 Service Regulators*

(a) When service is provided from distribution mains at pressures in excess of 1 psig, a proper service regulator, approved by the Gas Company, shall be used. A proper service regulator is one that can reduce the pressure to that required by the house piping system or to that recommended for household appliances.

(b) The service regulator(s) shall remain the property of the Gas Company.

(c) A single service regulator shall not serve more than eight (8) meters without Gas Company approval.

3.1.5 Regulator Relief Vent*

(a) Each service regulator that incorporates a relief device and is installed inside a building shall have a separate relief line vented outdoors to a safe location and meet the requirements of 3.1.5c.

1. If pipe is used for the vent line, the pipe shall be metallic and at least as large as the regulator vent opening.
2. If tubing is used for the vent line, the tubing shall be metallic and one size larger than the vent opening. Corrugated tubing shall not be used for regulator vents.
3. The outside terminal of each service regulator vent must be:
    - i. rain and insect resistant, and
    - ii. located at a place where gas from the vent can escape freely into the outside atmosphere to a safe location away from any opening into the building, and
    - iii. elevated to prevent submergence in areas where flooding may occur, and
    - iv. protected from damage.
4. Relief vent lines should be as short as practical, and when over 10' in length or contain more than two (2) elbows, should be increased one nominal pipe size for each 10' of length. Each elbow in the vent line will contribute about three (3) feet to the effective length, including the termination elbow.

(b) Service regulators installed outdoors of a building may use a metallic vent line to meet the distance requirements of 3.1.5(c) below, provided that it meets all the requirements specified in 3.1.5(a) above. PVC Plastic shall not be installed for vent lines after June 12, 2021.

(c) Except as noted below, the vent terminal:

1. Shall be installed outdoors above grade, at a minimum height of 12 inches above grade.
2. In areas where flooding may occur, a minimum height in excess of 12 inches may be required to prevent the entry of water into the vent terminal.
3. Shall be installed to protect it from the entry of insects by a screen or an approved vent cap, and be installed so as to prevent the entry of rainwater.
4. Shall be located not less than three (3) feet radially and not directly below any rotating electrical equipment (e.g., an air conditioning unit). See Appendix E.
5. Should be installed with a minimum of three (3) feet radial separation from an electric meter, electric panel, electric outlet, electric pedestal, electrical equipment disconnect, or pad mounted transformer, etc. When it is not possible to install the regulator vent terminal with a three (3) foot radial separation, a minimum of one (1) foot radial separation shall be maintained between the regulator vent terminal and any of the electric equipment listed above. See Appendix E.
6. Shall be located three (3) feet radially from, and not below, any first floor opening into a building, such as a door, window(s) (that can be opened) or other gravity air opening(s) into a building (including clothes dryer exhaust terminals, and appliance air intakes). See Appendix E.
7. Shall be located not less than ten (10) feet radially from, and not below any forced air inlet into a building (excluding appliance air intakes). See Appendix E.

NOTE: It may be acceptable for reduced clearances from building openings and potential sources of ignition when approved self-operated diaphragm service regulators equipped with over pressure protection and vent limiting devices are installed.

3.1.6 Establishing gas service

In no case shall a customer, his agent, or employee:

(a) Establish the initial gas service to a customer.

(b) Turn on the gas at the curb valve.

(c) Turn on the gas at the meter inlet valve.

(d) Reconnect the meter inlet or outlet when disconnected by an employee or agent of the Gas Company.

3.1.7 Interruption of service

When it is necessary to make house line piping repairs or alterations, and:

1. an outlet meter valve exists, a qualified pipe fitter or plumber may turn off the gas, complete the work in accordance with all applicable codes and standards, then re-establish the gas service; or
2. an outlet meter valve does not exist, then contact the Gas Company for inspection and testing.

EXCEPTION: *In OH, the Gas Company shall always be contacted to perform a leak test of the downstream piping and re-establish service.*

3.2 METER SETTING LOCATION*

3.2.1 General

(a) The Gas Company reserves the right to determine the location of the meter set assembly.

(b) New meter settings are to be located outside, except for a dedicated meter setting building, unless it is unavoidable and a representative of the Gas Company gives prior approval. New meter settings installed inside of a non-dedicated meter setting building shall comply with 3.2.1(e).

(c) The meter set assembly should be installed in a location where damage from outside forces is not reasonably expected to occur. Examples include, but are not limited to, vehicular traffic, snow and ice, construction equipment, and falling objects. Avoid installing the meter set assembly under fire escapes.

(d) Outside meter set assemblies shall be located such that potential damage from snow accumulation and/or falling ice and snow is limited. Locating the meter set assembly along an outside building wall under a roof gable or overhang should be sufficient protection.

(e) Existing meter settings located inside should be moved outside at the time of service line repair or replacement.

1. Meters remaining inside shall be in a well-ventilated space and not less than three (3) feet from any source of ignition or any source of heat which might damage the meter.
2. Settings remaining inside shall comply with 3.2.1(f) or (g) as applicable.
3. Settings remaining inside shall be located as near as practical to the riser or the point where the service line enters the building.

(f) Inside Meter Setting, Entrance Above Grade. Where the service line enters the structure above grade when the meter is to be located in the basement or on the ground floor level in a garage, utility room, or room approved for the meter location, an approved riser shall be installed in accordance with the requirements of 2.3.6(a) (see Sketch 6).

(g) Inside Meter Setting, Entrance Below Grade. Where the meter is to be located inside the basement of a building and the service line enters the structure below grade:

1. the inside piping should be installed to allow sufficient height for the meter set assembly, and
2. the wall head adapter shall be installed approximately six inches from the wall, and
3. all inside service line piping shall be exposed and accessible (see Sketch 6), and
4. underground metallic piping shall be coated and/or wrapped and have an anode installed, and
5. where the conduit passes through a wall it shall be encased in a sealed and approved steel or plastic sleeve or grout (see Sketches 5, 6, 7 & 8), and
6. the conduit shall:
   - (a) extend one foot outside the building line, and
   - (b) be sealed at the foundation wall to prevent leakage into the building, and
   - (c) terminate at a point inside the building that is accessible for service and inspection, and
   - (d) when under solid surfaces for more than 8′ from the point of entry the conduit shall be vented above grade to outside and be installed so as to prevent the entrance of water and insects (see Sketch 5 & 12).
7. In the case of plastic service line, be protected from shearing action and backfill settlement.

(h) When a service line is installed under a building:

1. the service line piping shall be encased in a gas tight conduit designed to withstand the superimposed loads, and
2. the space between the service line and conduit shall be sealed to prevent the possible entrance of any gas into the building, and
3. service line and conduit shall terminate at a point inside the building that is accessible for service and inspection, and
4. if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

(i) Meter settings should be perpendicular to the connection to the company service line (see Sketch 1). A short 90º off set at the side(s) of the building nearest the mainline may be permitted.

3.2.2 Meter Setting Accessibility

The meter set assembly shall be readily accessible for examination, reading, repair, and replacement.

3.2.3 Piping Accessibility

All piping, from the service line riser or point where the service line enters the building to the location of the meter set assembly, shall be exposed and accessible.

3.2.4 Ventilated Area

The meter set assembly shall not be installed in a small, unventilated, or confined space.

3.2.5 Protected from Damage

(a) The meter set assembly shall not be placed where it will be exposed to damage such as in driveways, parking lots, public passages, halls, coal bins, etc., or where it will be subjected to excessive corrosion or under fire escapes.

(b) Except for an engineered meter set assembly protection design, bollards shall be installed to protect the meter set assembly as set forth in this section.

(c) <u>Bollard Installation Requirements:</u>

1. Meter settings located less than 5 feet from a roadway, driveway or driving surface edge or road side edge of curb, shall be protected by the installation of at least 2 bollards.
2. Meter settings exposed to perpendicular vehicle parking shall have at least 2 bollards installed if the curb edge or edge of driving surface is less than 8 feet from the meter set.
3. Maximum spacing of bollards is 4 feet on center.
4. If more than 2 bollards are required to protect the meter set assembly, the maximum spacing of the bollards shall not exceed 4 feet.
5. Bollards shall be installed no closer than 1 foot from the front of the meter set assembly and shall be positioned to allow adequate room for operation and maintenance activities.

NOTES: A deviation from the standard 4" diameter bollard may be considered in residential, low speed, locations (e.g., where meter protection is required due to close proximity to a driveway). Any deviation from the above requirements shall be approved by local leadership overseeing the installation of the bollards and documented on the Service Line Record (see GS 3020.012 "Installation of Service Lines – Records").

See Appendix F for <u>typical</u> bollard application, spacing and installation requirements.

3.2.6 Protect from Heat/Ignition*

The meter set assembly shall be located in a readily accessible, ventilated area at a minimum distance of **three feet** (914mm) **from** any source of ignition or any source of heat that might damage the meter. Locations at which there are either extreme temperatures or sudden changes in temperatures should be avoided.

3.2.7 Regulator Location

(a) Regulators shall be located at a place where gas from the vent can escape freely into the outside atmosphere to a safe location away from any opening into the building.

(b) High-pressure regulators shall be installed outside of the building being served.

(c) Service regulators should be installed outside of the building where practical.

3.3 INSTALLATION

3.3.1 Meter Valve

A meter valve approved by the Gas Company shall be installed in the service line upstream of the meter and/or service regulator inlet (see 2.3.7).

3.3.2 Master Meter Valve

(a) When gas is supplied from a Low Pressure system to six or more meters on a manifold, a master valve controlling the gas supply to all meters must be provided in addition to the meter valves controlling the supply to each meter.

(b) Where a regulator is to supply two or more meter set assemblies, there shall be a master valve controlling the gas supply on the inlet side of the regulator in addition to the valves controlling the gas supply to each meter.

(c) Where manifold branches each require separate regulators, there shall be a valve controlling each regulator and there shall be a master valve controlling the gas supply to all regulators in addition to the valves controlling the gas supply to each meter.

Note: The master valve does not have to be of the insulating type. Manifolds shall be insulated in accordance with paragraph 3.3.7.

3.3.3 Meter Tags

On multiple meter installations, each meter valve or house line shall be plainly and properly identified by the installing agent with a weatherproof tag or other approved means of designating the apartment or the part of the building it supplies.

3.3.4 Manifold Piping

(a) Manifolds should not be more than two tiers high.

(b) A single regulator should not serve more than eight (8) meters.

(c) Distance from the riser to the top of the header piping should not exceed six (6) feet.

(d) Valves are required for the header, for each regulator, and for each meter.

(e) Manifolds shall be as close as practicable to header piping.

(f) Normally, piping making up an outside manifold meter set assembly shall be located above ground. However, if all joints to the manifold header are made by welding and the manifold header and risers are coated with an approved material and protected by a magnesium anode, this piping may be located underground.

3.3.5 Meter Clearance

Distance between meter and any obstruction to the sides, rear, top, or bottom shall be minimum of six (6) inches. Distance between the meter and any obstruction from the front shall be a minimum of thirty (30) inches. On outside meter settings, the bottom of the meter shall be a minimum of six (6) inches above finished grade.

3.3.6 Plumb and Level

Meter set assemblies shall be plumb and level so that the meter will line up properly with the meter connections.

3.3.7 Electrical Isolation, Grounding, and Bonding

(a) Gas piping shall not be used as a grounding conductor.

(b) An insulator shall be installed in the meter setting to electrically isolate the service line from the house line. Insulation is normally provided through the use of insulated meter valves but insulated bars, swivels, unions, couplings, or flanges may be required in some instances.

(c) House line bonding wires shall not be connected to meter settings, meter manifolds, or service lines. The house line bonding wire shall be connected to the ground in the electrical breaker box or the building electrical ground rod, and at a house line fitting or pipe as close to the electric panel as practical. Connecting in a close proximity to the gas meter is also desirable.

3.3.8 Meter Support

To minimize stress on the piping and meter, the meter setting must be properly supported, by rigidly supporting the riser and rigid support either provided by the house line connection or alternative means if no house line initially exists.

For remote settings (cannot be attached to foundation bracket), refer to Sketch 10 in Appendix D.

3.3.9 Corrosion Protection

(a) Above ground metallic pipelines outside that are exposed to atmosphere shall be cleaned and either coated or painted with a suitable material to prevent corrosion.

(b) Underground metallic pipelines shall be coated and/or wrapped and cathodically protected.

3.3.10 Thread Sealant

Where threaded connections are made on the aboveground piping, a sealant approved for natural gas shall be applied according to the manufacturer's instructions.

3.4 METER SIZING*

Meter sizing is based on gas demand in cubic feet per hour (load).

1. ***Residential*** – input of space and water heating equipment. When the input rate of other appliance(s) such as a pool heater or air conditioner is more than the furnace the total of the greater should be used. In the absence of central heating equipment, load requirements shall be determined from the total input requirements for all appliances.
2. ***Commercial*** – input of all connected appliances.
3. ***Diversity Factor*** – ratio of the maximum probable demand to the maximum possible demand.

3.5 MANUFACTURED (MOBILE) HOME METER SET ASSEMBLY

3.5.1 Connection to house lines

See Sketch No. 9.

(a) The meter setting shall be rigidly supported at both the riser and on the house lines.

(b) An approved manufactured (mobile) home connector shall connect the meter setting to the house lines. The gas supply connection shall not be located beneath an exit door and the connector end must be located outside of the skirting.

(c) The manufactured (mobile) home connector shall be listed, and:

1. installed in accordance with manufacturer's instructions, and
2. shall not be less than ¾-inch I.D. tubing size, and
3. shall not be more than 40 inches in length.

3.6 HIGH PRESSURE SERVICE REGULATOR SETTINGS

3.6.1 Distribution Notification*

When service is provided from a high pressure line not part of the distribution system from which customers are normally supplied, the Gas Company's Distribution Service Department shall be consulted for customer service line requirements and specifications.

3.6.2 Location

High-pressure regulators SHALL be located outside the building being served.

PART 4 - INSPECTION, TESTING, AND PURGING

4.1 INSPECTION AND TEST REQUIREMENTS

Requirements for customer owned service lines and meter setting installations.

4.1.1 Customer charges

The first inspection and/or test shall be without charge. In the event the lines will not pass such inspection and test or if other unsatisfactory conditions result in the disapproval, the necessary correction(s) shall be made at the owner's expense and the line involved shall again be inspected and tested. Additional inspection(s) and/or test(s) shall be subject to a charge.

4.1.2 Notification for Testing

(a) The customer or customer's representative will make arrangements for the installation, inspection and testing of the customer service line in accordance with the standards and information set forth in this manual and house lines in accordance with the National Fuel Gas Code.

(b) Call the Gas Company requesting visual inspection, pressure test, and meter installation after the following conditions have been met:

1. Service Line, house lines, meter setting, and appliances, when applicable, are ready for inspections and tests.
2. Where required, documentation of an Approval for Natural Gas Service from Building Code Officials
3. Access to all parts of the building with gas piping and/or appliances will be available to Gas Company personnel.

4.1.3 Visual Inspection

(a) The Gas Company shall visually inspect the customer service line before backfilling any excavation(s) made during plastic insert renewal work, boring, or vibra-plow installation of piping.

(b) A plastic service line installed in a trench may be back filled for protection; however, the end connections and all fittings shall remain exposed for visual inspection.

(c) Steel service lines shall be visually inspected before back filling any excavation(s).

(d) Isolated metal fittings underground shall be visually inspected for a properly sized attached anode prior to being coated and/or wrapped. They shall be coated and/or wrapped prior to backfill. An additional trip to visually inspect coating and/or wrapping is not required.

4.2 NEW AND REPLACED SERVICE LINES

Additional requirements for new and replaced customer-owned service lines and meter setting installations.

4.2.1 New Construction Pressure Test Requirements (2" and under)*

A new customer service line shall be given a pressure test after construction and before being placed in service to demonstrate that it is gas tight. Service lines shall be pressure tested at **1.5 x MAOP or 90 psig**, whichever is greater, for at least **5 minutes** with **no drop** in pressure, and a leakage check shall be made at operating pressure of all exposed fittings in the service line that were not included in the pressure test.

Note: *For service lines to operate at pressures above 99 psig, consult the Gas Company.*

4.2.2 Pressure test gases

4.2.3 Air, nitrogen, carbon dioxide, or other inert gas shall be used to pressurize gas lines for testing. Establishing gas service

A representative of the Gas Company shall establish gas service after passing the required inspection and test. In no case shall a customer or his agent or employee turn on the gas at the curb valve, meter valve, or reconnect the meter inlet or outlet.

4.2.4 Meter Installation

A gas meter may be set and the gas turned on if the service line, meter setting, and installed house lines pass required inspection and testing.

(a) The meter setting shall be in the permanent location, properly supported, and the permanent house line piping meets at least one of the following requirements:

1. House line piping is properly connected to all appliance(s) and any unused trunk, branches, and stub piping shall be capped or plugged. Where required, there shall be documentation of an Approval for Natural Gas Service from a Building Code Official; or
2. **PA** – Refer to section 1.3.2 "Arrangements for Establishing Gas Service".

4.3 ABANDONED, TEMPORARILY DISCONNECTED, OR PARTIALLY REPLACED*

The following are additional requirements for abandoned, temporarily disconnected, or partially replaced customer owned service lines and meter setting installations.

(a) Abandoned service lines shall not be reinstated – regardless of material.

(b) A visual inspection is required only on that portion of the service line that required exposure for work.

(c) Testing shall be in accordance with the following:

1. Service lines temporarily disconnected or partially replaced shall be pressure tested from the point of disconnection to the meter valve in accordance with 4.2 (as NEW) or 4.3(c)4 (BARE STEEL at LOW PRESSURE) before reconnecting. All piping installed for replacement shall be included in the test section.
2. After completion of the initial test, the piping of the tested section shall be reconnected to the upstream section of the service line. After reconnection when the curb valve has been turned off, the entire service line shall be tested at operating pressure for 3 minutes with no drop in pressure. When the curb valve does not exist or has not been turned off, the Company shall perform a surface gas detection survey over the service line as an alternative to 4.3(c)1, the entire service line from curb valve to meter valve may be tested in accordance with 4.2 or 4.3(c)4 after repairs have been made <u>if the service line has a curb valve rated to handle the test pressure</u>.
3. A leakage check at operating pressure shall be made on all exposed fittings in the service line that were disturbed or not included in the pressure test.
4. Service lines containing only BARE STEEL to be operated at a pressure of less than 1 psig (LOW PRESSURE):
   1. shall be given a pressure test with no drop in pressure at not less than:

      PA – 10 psig for at least 5 minutes.
   2. that have a partial replacement involving the riser ONLY:

PA –need not be tested in the same manner as a new service line. The entire service line, including the riser, may be tested at operating pressure for 3 minutes with no drop in pressure.

Exception: *If provisions are made to maintain continuous service (such as by installation of a by-pass), any portion of the original service line used to maintain continuous service need not be tested.*

4.4 REESTABLISHING GAS SERVICE*

4.4.1 Leak detection

(a) When re-establishing service that has been turned off at the curb valve, the customer service line **shall** be tested with natural gas, air, or an inert gas at not less than operating pressure for not less than three minutes with no loss in pressure.

(b) A CGI test at intervals over the service line is permitted when re-establishing service that has **NOT** been turned off at the curb valve.

(c) A leakage check shall be made at operating pressure of all exposed fittings in the service line that were not included in the pressure test. An electronic leak detector, combustible gas indicator (CGI), or a leak finder liquid (bubbles) may be used to locate leaks.

***Note**: In no case shall any gas that affects flammability or produces a toxic atmosphere when burned, such as ether (as an odorant), Freon, oxygen, or acetylene be used to locate leaks.*

4.5 PURGING PIPELINES*

4.5.1 Purging with natural gas

When placed in operation the air in piping can be safely displaced with fuel gas provided that a moderately rapid and continuous flow of fuel gas is introduced at one end of the line and air is vented out at the other end. The fuel gas flow shall be continued without interruption until the vented gas is free of air.

4.5.2 Purging with air

There is a greater potential risk of accidental ignition within a pipeline when purging with air because of the slower introduction of air creating a greater area of combustible gas mixtures. When gas piping is to be opened for servicing, addition, or modification, the section to be worked on shall be turned off from the gas supply. The line pressure shall be vented to the outdoors or to ventilated areas of sufficient size to prevent accumulation of flammable mixtures.

4.5.3 Purge Points*

(a) The service line shall be purged prior to checking/setting regulator flow and lock-up.

(b) The meter inlet shall be connected and purged while observing the meter test dials for movement prior to connecting the meter outlet.

(c) The house piping shall be purged at all connected appliances prior to placing in operation to prevent injury or property damage.

***Note:** Piping shall NOT be purged into a confined space or the combustion chamber of an appliance. All potential sources of ignition shall be eliminated. The point of discharge shall NOT be left unattended during purging.*

4.5.4 Smell Check During Purging

A combustible gas in a distribution line must contain a natural odorant or be odorized so that the gas is readily detectable by a person with a normal sense of smell. To assure the gas has odorant, each person purging piping into service must conduct a smell check of combustible gases. If the natural gas smell is not readily detectable immediately suspend the purge and notify the Gas Company.

4.6 RECORD OF RESULTS

The Gas Company representative will record inspection and test results. If the service line fails the inspection or test, the owner, plumber, or owner's representative will be notified.

APPENDIX A - Additional Explanatory Material

Appendix A contains additional explanatory material and excerpts from relevant codes numbered to correspond with the applicable text paragraphs.

A.1.3.2 Arrangements for Establishing Gas Service*

Gas Company contact phone numbers:

New Business:	(800)440-6111
	(614)481-1698 - FAX
Customer Contact Center:	(800) 344-4077

Note: *Phone numbers are subject to change without notice.*

"Standards for Customer Service Lines, Meters, and Service Regulators" (Plumber's Guide); New Tap and Meter Process, Materials for Customer Service Lines, Standard Drawings for Meter Settings, Operator Qualification Card, Mechanical Joint Card, and Plumber's Guide Revision Proposal Form are available for Pennsylvania @ http://www.columbiagaspa.com/

A.2.2.3 Installation of service lines under buildings*

Some local code officials are interpreting IRC (IFGC) G2415.8 (404.8) and G2415.11 (404.11) to mean that service and/or house lines are not allowed to be installed under buildings, such as garages, and are turning them down. Local code officials should be consulted before allowing any piping under buildings. Follow the guidelines for "Cased Steel Gas Line Laid Under Building" (Plumber's Guide Sketch No. 12).

DOT 192.361 Service lines: Installation

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

National Fuel Gas Code, section 7.1.6, "Piping Underground Beneath Buildings" shall be consulted for house lines under buildings.

A.2.3.2 Steel Service Pipe*

All steel service line material, welding, inspecting and installation shall be in accordance with CFR Title 49 – Part 192. Welding procedures and welders performing work on the customer's jurisdictional piping systems shall be qualified by NiSource Welder Qualifications and use NiSource approved welding procedures. Contact Columbia Gas of PA's Engineering Department for approved welding procedures and guidance on applicable code requirements.

A.2.3.3 Mechanical Fittings*

Mechanical fittings can be used to join dissimilar materials such as plastic to steel or high density plastic to medium density plastic, and to join different sizes such as 1″ to 1 ¼″.

A.2.3.4 Plastic Fusion Fittings*

(a) Butt Fusion – Not permitted for nominal diameters less than 2″ or mitered cuts. Only fusions for medium-density (yellow) to medium-density, or high-density (black) to high-density are permitted. Use a mechanical joint or an electrofusion for dissimilar plastics. A mechanical joint shall be used for plastic to steel.

(b) Socket Fusion – Effective June 12, 2021 socket fusion is not permitted as a joining method.

(c) Electrofusion – May be used to join plastic pipe of the same or dissimilar plastic designations.

A.2.4 SERVICE LINE SIZING* – See APPENDIX C – Service Line Sizing.

A.2.5.3 Joining Pipe* (h)

Columbia Gas policy and procedure, and DOT require qualification. The "Operator Qualification Card" (Form C-3363) is the Gas Company's method of determining the person making the joint is qualified by DOT Operator Qualification (OQ) Training.

The information area on the front of the form must be completed properly and legibly. All information must be provided and must be signed attesting the person making the joints is qualified to do so. The back of the form is to be completed ONLY by Gas Company personnel. See Appendix E for the Operator Qualification Card.

A.3.6.1 Distribution Notification* (High-pressure settings)

Approval is required from the Gas Company for high pressure meter settings. The customer will pay an aid-to-construction charge. The Gas Company, upon approval and payment, will provide first- and, if required, second-cut regulators and build the high-pressure setting on the pipeline.

PA: The final-cut service regulator, or pre-fabricated meter setting, shall be customer-purchased and installed to provide gas to the house lines from the meter located in the easement.

A.4.2.1 New Construction Pressure Test Requirements (2″ and under)* &

A.4.3 ABANDONED, TEMPORARILY DISCONNECTED, OR PARTIALLY REPLACED*

Service Line Testing

Service Lines 2″ & Under, New or Repaired, GS 1500.010			
Minimum Test Requirements:	**Time**		**Pressure**
	300 ft and less	301 ft to 1,750 ft	
MDPE Plastic Pipe	5 minutes	1 hour	90 psig
HDPE Plastic Pipe	5 minutes	1 hour	150 psig
Steel Pipe (less than 30% SMYS)	5 minutes	1 hour	1.5 x MAOP* or 90 psig, whichever is greater

Note: Contact the Gas Company for lengths over 1,750 feet

Service Lines Sizes 3", 4" and 6", New or Repaired, GS 1500.010			
Minimum Test Requirements:	**Time**		**Pressure**
	200 ft and less	201 ft to 400 ft	
MDPE Plastic Pipe	1 hour	2 hours	90 psig
HDPE Plastic Pipe	1 hour	2 hours	150 psig
Steel Pipe (less than 30% SMYS)	1 hour	2 hours	1.5 x MAOP* or 90 psig, whichever is greater

Note:

1. *When the test time is required to be greater than 1 hour, a pressure recording gauge shall be used to record the test pressure.*
2. *Contact the Gas Company for testing sizes greater than 6", lengths greater than 400 ft or steel pipe at or above 30% SMYS*

Service Line Testing, Existing, GS 6500.050		
Test Requirements:	**Time**	**Pressure**
Pressure Drop Test	3 minutes	Operating
CGI Test - at intervals over the service line and in the vicinity of the curb box.		

NOTES for Abandoned, Temporarily Disconnected or Partially-Replaced Service Lines:

(a) Service lines previously **abandoned** <u>shall not be reinstated</u>.

(b) Service lines **temporarily disconnected** or **partially replaced shall be tested as new.**

1. Service lines **temporarily disconnected** or **partially replaced shall be tested** from the point of disconnection to the meter valve in the same manner **as new** service lines before reconnecting. Replaced piping shall be included in the test section. The piping of the tested section shall be reconnected to the upstream section of the service line and the entire line shall be tested at operating pressure for 3 minutes with no drop in pressure.
2. Service lines **temporarily disconnected** or **partially replaced** may be reconnected and the entire customer-owned service line, to the meter valve, tested as new.

Exceptions:

1. ***Low pressure BARE*** *(see P&P 725-7)* ***STEEL*** *service lines will be given a pressure test at not less than* ***10 psig for at least 5 minutes (10 min. in OH)*** *with no drop in pressure.*
2. *A* ***partial replacement*** *involving* ***the riser only on a low pressure BARE STEEL*** *service line (P&P 725-7, 3.2) need not be tested in the same manner as a new service line provided the entire service line, including the riser, is tested at* ***operating pressure for 3 minutes*** *with no drop in pressure after completion of the replacement.* ***In OH, the riser shall be tested as new.***

A.4.5 PURGING PIPELINES*

Combustible gas air mixtures will be present at both the discharge point and within the pipeline at some point during the purge so elimination of potential sources of ignition is crucial. Venting hazardous amounts of gas is not permitted unless specific safety requirements, including but not limited to additional personnel standing by with a fire extinguisher and control through signs, tape, and other personnel to control the perimeter, are used. Pipe volumes indicated by NFGC Tables 7.3.1 and 7.3.2 shall be displaced with an inert gas such as nitrogen or carbon dioxide.

A.4.5.3 Purge Points*

Only a representative of the Gas Company is permitted to open the curb valve or reconnect a meter. Gas Company personnel shall purge at the service line prior to setting regulator lockup and flow, at the meter outlet to ensure proper meter operation, and at all connected appliances prior to placing in operation to prevent injury or property damage.

APPENDIX B - Meter Kind & Size, Capacity, and Dimensions

Notes:

1. *Meters operating at 7" w.c. should be sized based on a 0.5" w.c. differential.*
2. *Meters operating at 0.5 psig to 2 psig may be sized based on a 1.0" w.c. differential.*
3. *Meters operating at 2 psig or greater may be sized based on a 2.0" w.c. differential.*
4. *For meter setting drawings, consult the Gas Company.*
5. *Capacity of Romet and Roots rotary meters is the manufacturer's rated capacity, and is not sized for a pressure drop.*

** Index on top of meter is higher than top of swivel when set.*

Manufacturer	Kind & Size	Model Number	Capacity [cfh]			Pipe Size	Center Spread	Height w/ Swivels	Meter Dimensions [in.]		
			1/2" Drop	1" Drop	2" Drop		[in.]	[in.]	Height	Width	Depth
American Meter	608	AC-250	250	375	540	1	6	16.75	12.75	8.8125	8.75
	616	AL-425	425	625	900	1-1/4	8.25	18	15	10.625	10.5
	619	AC-630	630	940	1,355	1-1/4	8.25	18	15	10.625	10.5
	607	AC-800	800	1,150	1,355	1-1/4	8.25	18	15	10.625	10.5
	612	AL-800	800	1,150	1,700	1-1/2	11	23.5*	23.3125	14.125	13.25
	611	AL-1000	1,000	1,450	2,200	1-1/2 or 2	11	23.5*	24	14.625	13.25
Sensus (Rockwell)	823	R-275	275	410	590	1	6	18	13.375	10.125	8.5
Itron (Schlumberger, Sprague)	760	Metris	250	375	540	1	6	18	11.3	7.7	6
	770	I-250	250	375	540	1	6	18	14.4	9.5	8.2
	765	400A	400	600	900	1-1/4	8.25	14.75	14.7	10.9	8.8
	766	800A	800	1,150	1,700	2	11	23.25*	23.4	15.7	13.9
	767	1000A	1,000	1,450	2,200	2	11	23.25*	23.4	15.7	13.9

Manufacturer	Kind & Size	Model Number	Capacity [cfh]			Pipe Size	Center Spread [in.]	Height w/ Swivels [in.]	Meter Dimensions [in.]		
			1/2" Drop	1" Drop	2" Drop				Height	Width	Depth
Romet	685	RM2000	2,000	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
	686	RM3000	3,000	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
	687	RM5000	5,000	Not	Applicable	3	6.75	NA	6.75	Varies	Varies
	688	RM7000	7,000	Not	Applicable	3	9.5	NA	9.5	Varies	Varies
	689	RM11000	11,000	Not	Applicable	4	9.5	NA	9.5	Varies	Varies
	682	RM16000	16,000	Not	Applicable	4	9.5	NA	9.5	Varies	Varies
	762	RM23000	23,000	Not	Applicable	4	9.5	NA	9.5	Varies	Varies
Roots /	742	8C	800	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
Dresser	743	11C	1,100	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
	744	15C	1,500	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
	741	2M	2,000	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
	745	3M	3,000	Not	Applicable	2	6.75	NA	6.75	Varies	Varies
	747	5M	5,000	Not	Applicable	3	6.75	NA	6.75	Varies	Varies
	748	7M	7,000	Not	Applicable	3	9.5	NA	9.5	Varies	Varies
	749	11M	11,000	Not	Applicable	4	9.5	NA	9.5	Varies	Varies
	750	16M	16,000	Not	Applicable	4	9.5	NA	9.5	Varies	Varies

APPENDIX C – Service Line Sizing

How to Size a Gas Service Line

House lines should be sized in accordance with the National Fuel Gas Code.

In determining the size of service lines to be used in designing a gas piping system, ALL SIX of following factors must be considered:

1. **Pipe Material** (plastic pipe or steel pipe)

   Note: *Plastic pipe tables are in the Plumber's Guide.*

   Steel Pipe requires special tables or calculations.

2. **Gas supply pressure**

   Low Pressure – normally 7 to 14 inches of water column.

   Intermediate Pressure – normally 2 to 10 psig, but may drop to **1 psig** during times of high demand.

   Medium Pressure – normally 10 to 60 psig, but may drop to **2 psig** during times of high demand.

   High Pressure – over 60 psig, and may exceed 1000 psig.

3. **Allowable loss in pressure from the main to the meter**

   Tables provide for:

   Low pressure - 0.5" w.c.

   Intermediate pressure - 5.0" w.c.

   Medium pressure - 16" w.c.

   High pressure – 2 psig

4. **Specific gravity and Heating Value content of the gas**

   Columbia distributes **Natural Gas** with a Specific Gravity of **0.6** and a normal Heating Value of **1000 Btu's**/cu. ft.

5. **Length of the service line, from the main to the meter**

6. **Gas demand in Cubic Feet / Hour (CFH)**

   Residential – input of furnace and water heater. In the absence of central heating equipment, load requirements shall be determined from the total for all appliances.

   Commercial – input of all connected appliances.

   Diversity Factor – ratio of the maximum probable demand to the maximum possible demand.

Note: *Btu rating of gas appliances divided by 1000 = CFH.*

TABLE 1

Maximum Capacity of Plastic Pipe in CFH for Service Lines Operated at Low Pressure

(Based on a Pressure Drop of 0.5" Water Column and 0.6 Specific Gravity Gas.)

Distance Main to Meter in Feet

MDPE Plastic	10	50	100	150	200	250	300
1" CTS	373	167	118	96	83	75	68
1 1/4" IPS	1074	480	340	277	244	215	196
2" IPS	3,160	1,410	1,000	820	710	630	580
3" IPS	9,280	4,150	2,940	2,400	2,030	1,860	1,700
4" IPS	18,430	8,240	5,830	4,760	4,120	3,690	3,360
6" IPS	51,820	23,180	16,390	13,380	11,590	10,360	9,460

Table has allowed for normal fittings.

Low-Pressure Service Lines. Low-pressure customer service lines shall not be less than 1 inch CTS.

TABLE 2

Maximum Capacity of Plastic Pipe in CFH for Service Lines Operated at Intermediate Pressure (1 psig minimum)

(Based on a Pressure Drop of 5.0" Water Column and 0.6 Specific Gravity Gas.)

Distance Main to Meter in Feet

MDPE Plastic	10	50	100	150	200	250	300
3/4" CTS *	450	230	170	140	120	110	100
1" CTS	750	480	360	300	270	240	220
1 1/4" IPS	1,690	1,200	940	800	710	640	590
2" IPS	2,410	2,180	1,970	1,810	1,680	1,580	1,490
3" IPS	10,530	8,700	7,360	6,490	5,880	5,410	5,030
4" IPS	20,890	17,260	14,600	12,890	11,660	10,730	9,990

* ONLY piping and reducing fittings are approved, and for insertion in 1 inch metallic pipe.

Table has allowed for normal fittings.

Intermediate-Pressure Service Lines. Intermediate-pressure customer service lines shall not be less than 3/4 inch CTS.

Exception: Prior approval from the Gas Company Engineering Department shall be obtained to install 1/2 inch CTS (5/8 inch OD) piping on systems specifically designed to operate at 1 psig minimum pressure.

TABLE 3

Maximum Capacity of <u>Plastic Pipe</u> in CFH for Service Lines Operated at <u>Intermediate*</u> or <u>Medium Pressure</u> (2 psig minimum)

(Based on a Pressure Drop of 16" Water Column and 0.6 Specific Gravity Gas.)

<u>Distance Main to Meter in Feet</u>

MDPE Plastic	10	50	100	150	200	250	300
1/2" CTS	470	220	150	120	105	93	84
3/4" CTS **	1,060	640	470	390	330	300	270
1" CTS	2,290	1,380	1,010	830	720	640	578
1 1/4" IPS	4,660	3,190	2,450	2,040	1,780	1,600	1,460
2" IPS	5,750	5,140	4,590	4,180	3,850	3,590	3,370
3" IPS	24,380	19,720	16,380	14,250	12,760	11,630	10,740
4" IPS	48,870	39,530	32,830	28,570	25,570	23,310	21,530

* If the system is Intermediate Pressure (IP) and the minimum pressure is not known, use Table 2 – Intermediate Pressure (1 psig minimum).

** ONLY piping and reducing fittings are approved, and for insertion in 1 inch metallic service lines.

Table has allowed for normal fittings.

Medium-Pressure Service Line. Medium-pressure customer service lines <u>shall not be less than 1/2 inch CTS</u>.

TABLE 4

Maximum Capacity of Plastic Pipe in CFH for Service Lines Operated at High Pressure (61 psig minimum)

(Based on a Pressure Drop of 2 psig and 0.6 Specific Gravity Gas.)

Distance Main to Meter in Feet

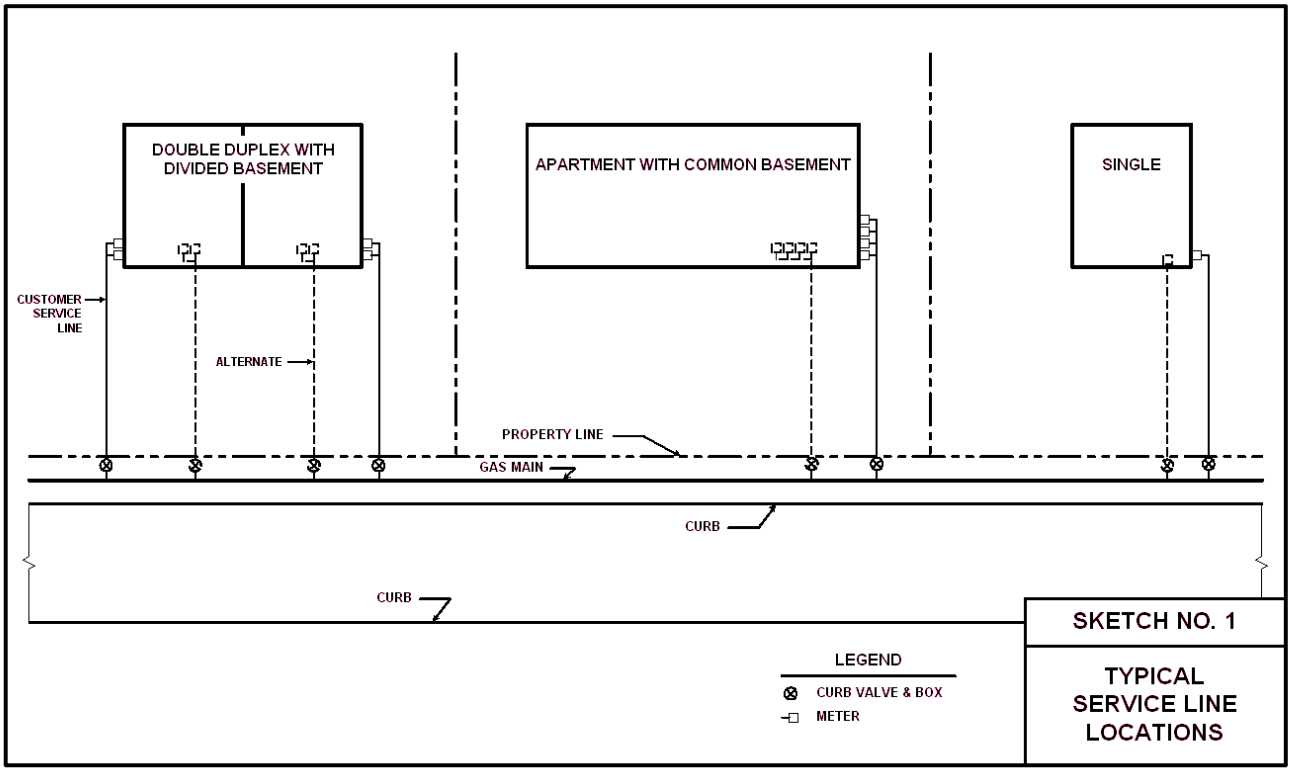
HDPE Plastic	10	50	100	150	200	250	300
1/2" CTS	1,920	980	690	560	480	420	380
1" CTS	9,990	6,170	4,560	3,750	3,250	2,900	2,640
1 1/4" IPS	21,390	14,650	11,220	9,370	8,190	7,340	6,700
2" IPS	26,370	23,580	21,050	19,150	17,670	16,470	15,470
3" IPS	111,830	90,450	75,130	65,380	58,510	53,340	49,280

Table has allowed for normal fittings.

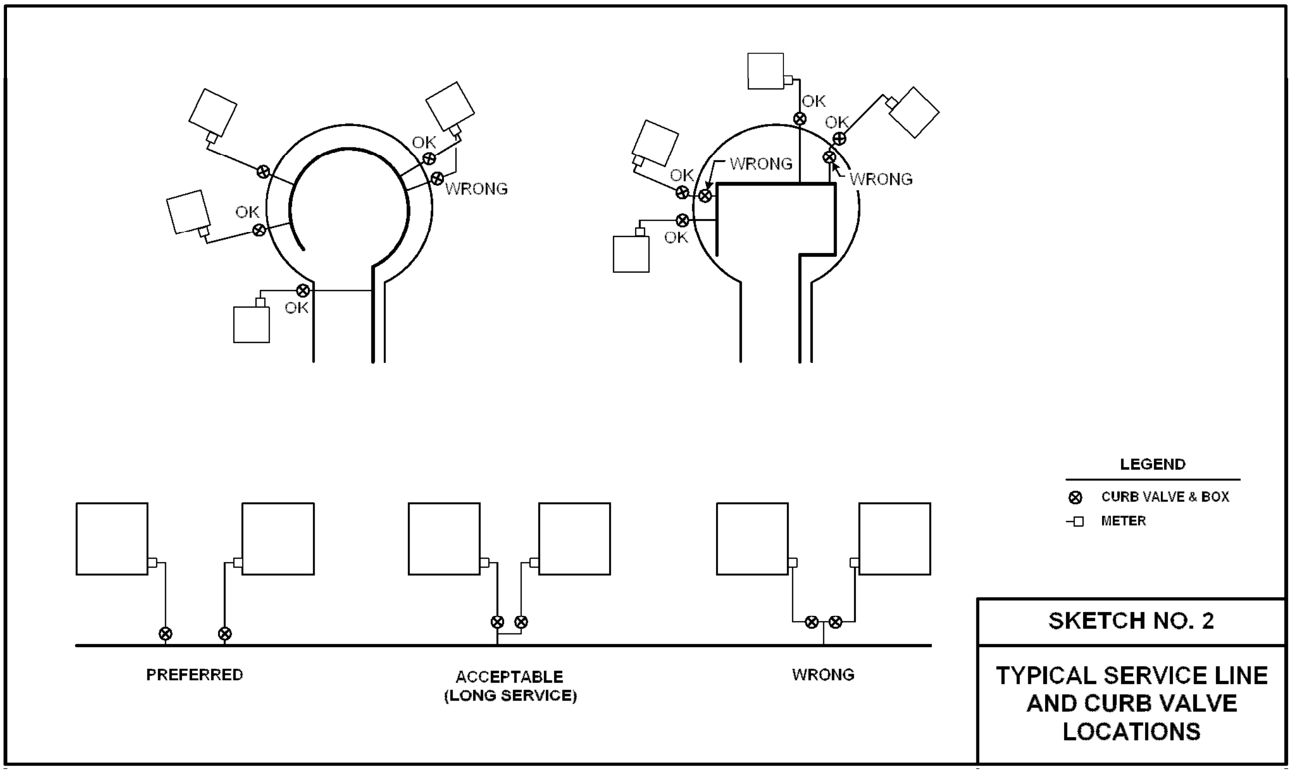
High-Pressure Service Line. High-density polyethylene plastic (HDPE – black PE-3408/3608) may be installed to a maximum pressure of 99 psig.

APPENDIX D - Sketches

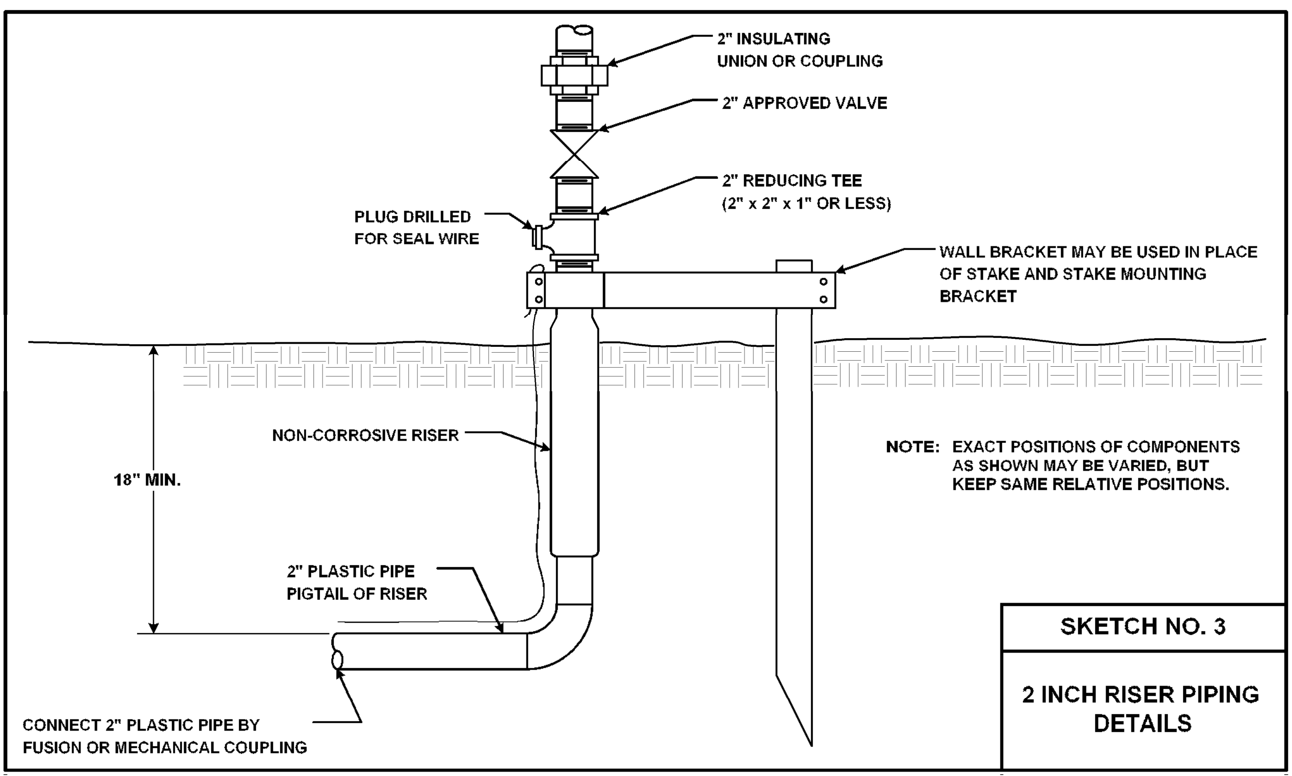
Sketch No. 1 - Typical Service Line Locations



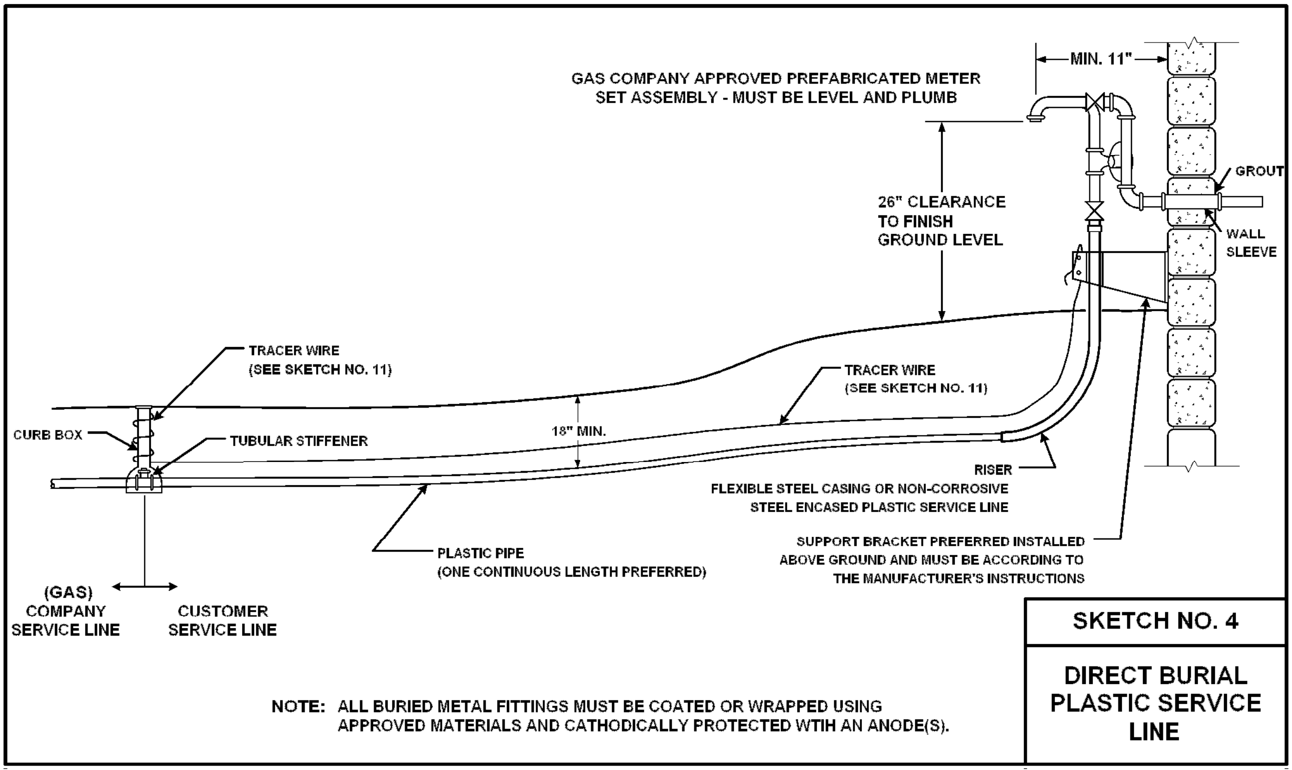
Sketch No. 2 - Typical Service Line and Curb Valve Locations



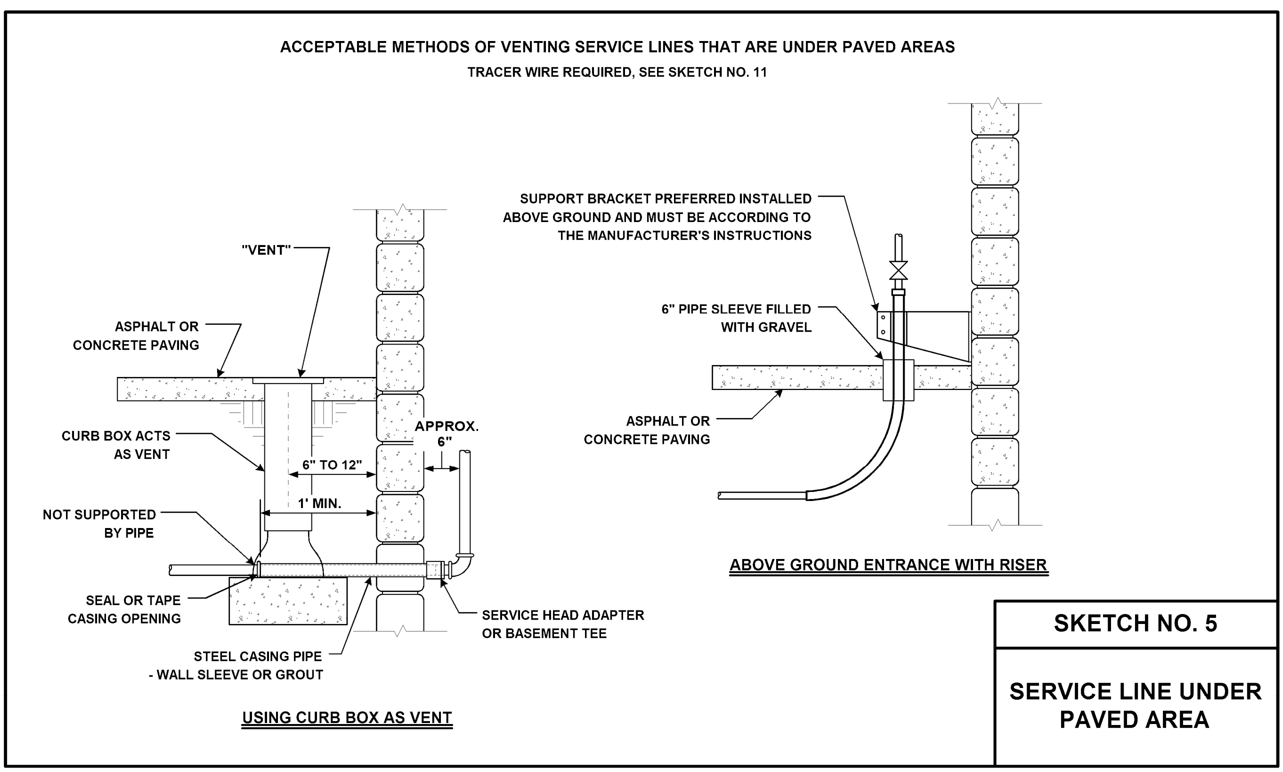
Sketch No. 3 - 2 inch Riser Piping Details



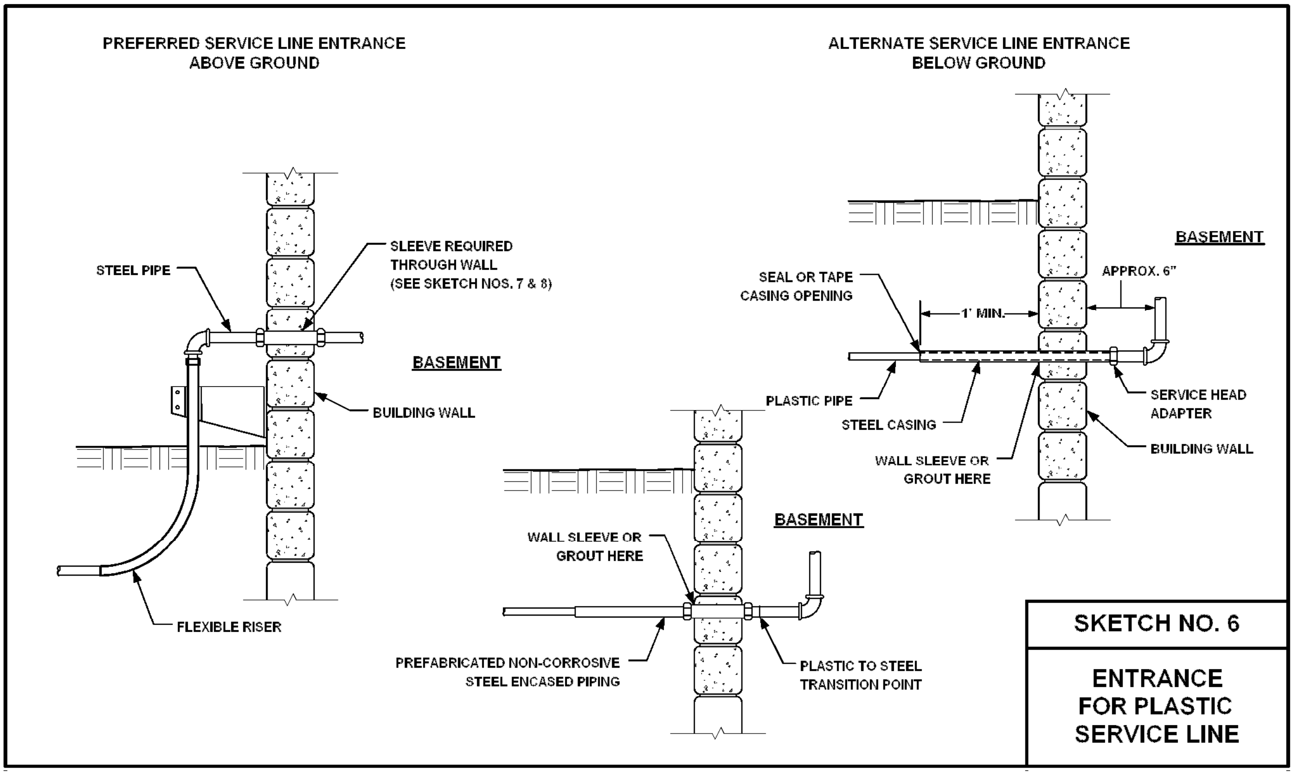
Sketch No. 4 - Direct Burial Plastic Service Line



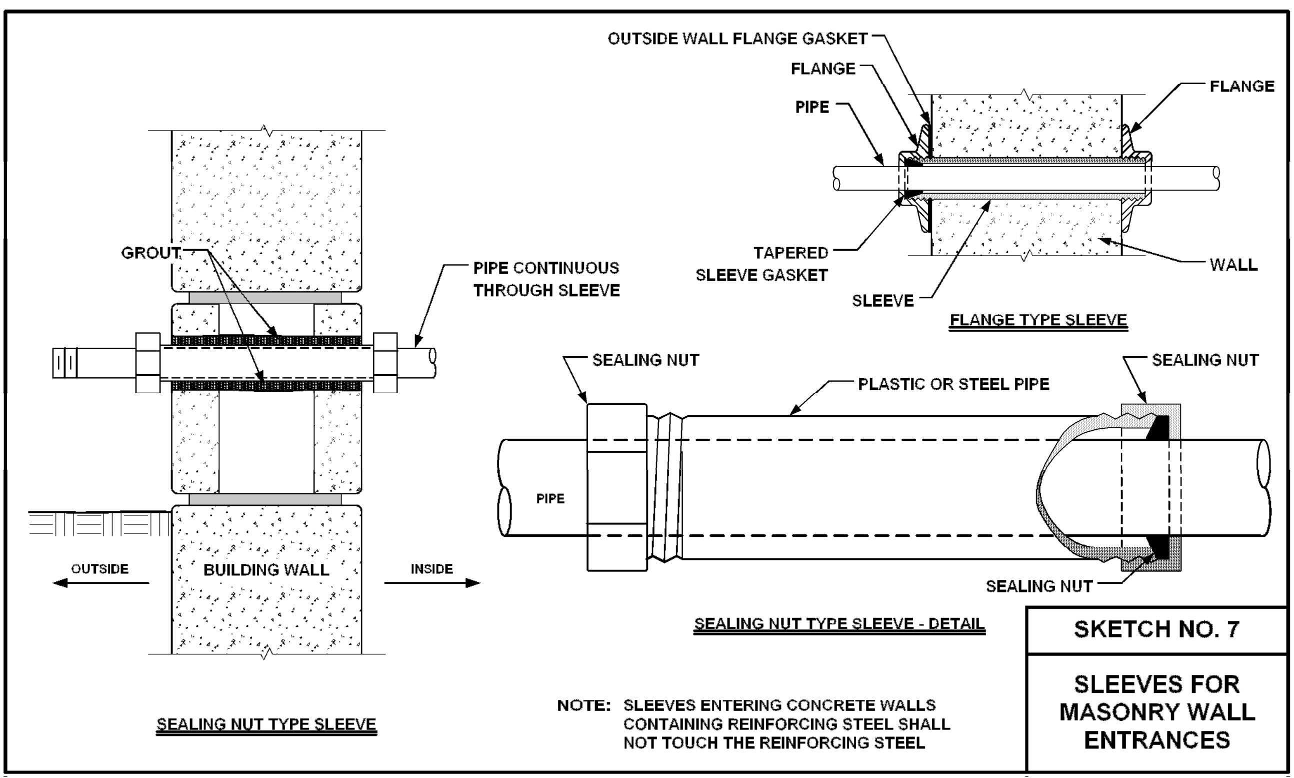
Sketch No. 5 - Service Line Under Paved Area



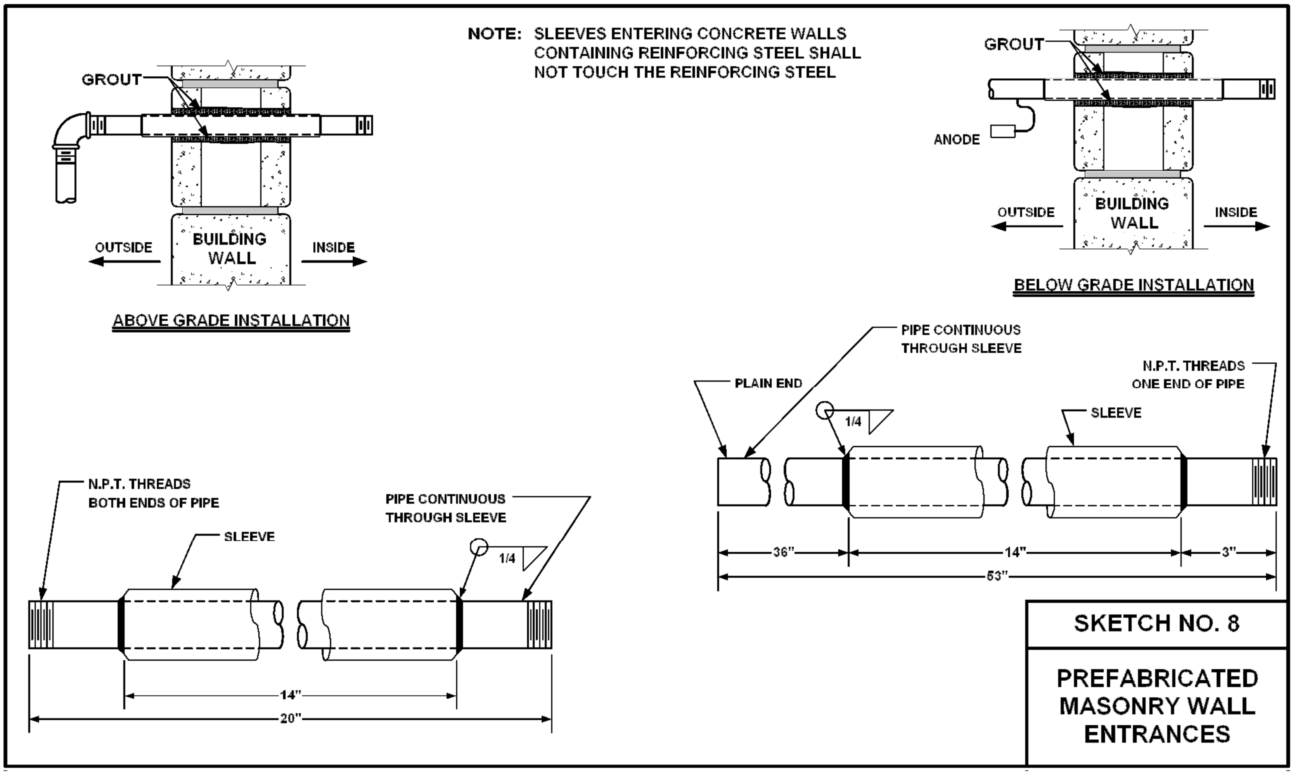
Sketch No. 6 - Entrance for Plastic Service Line



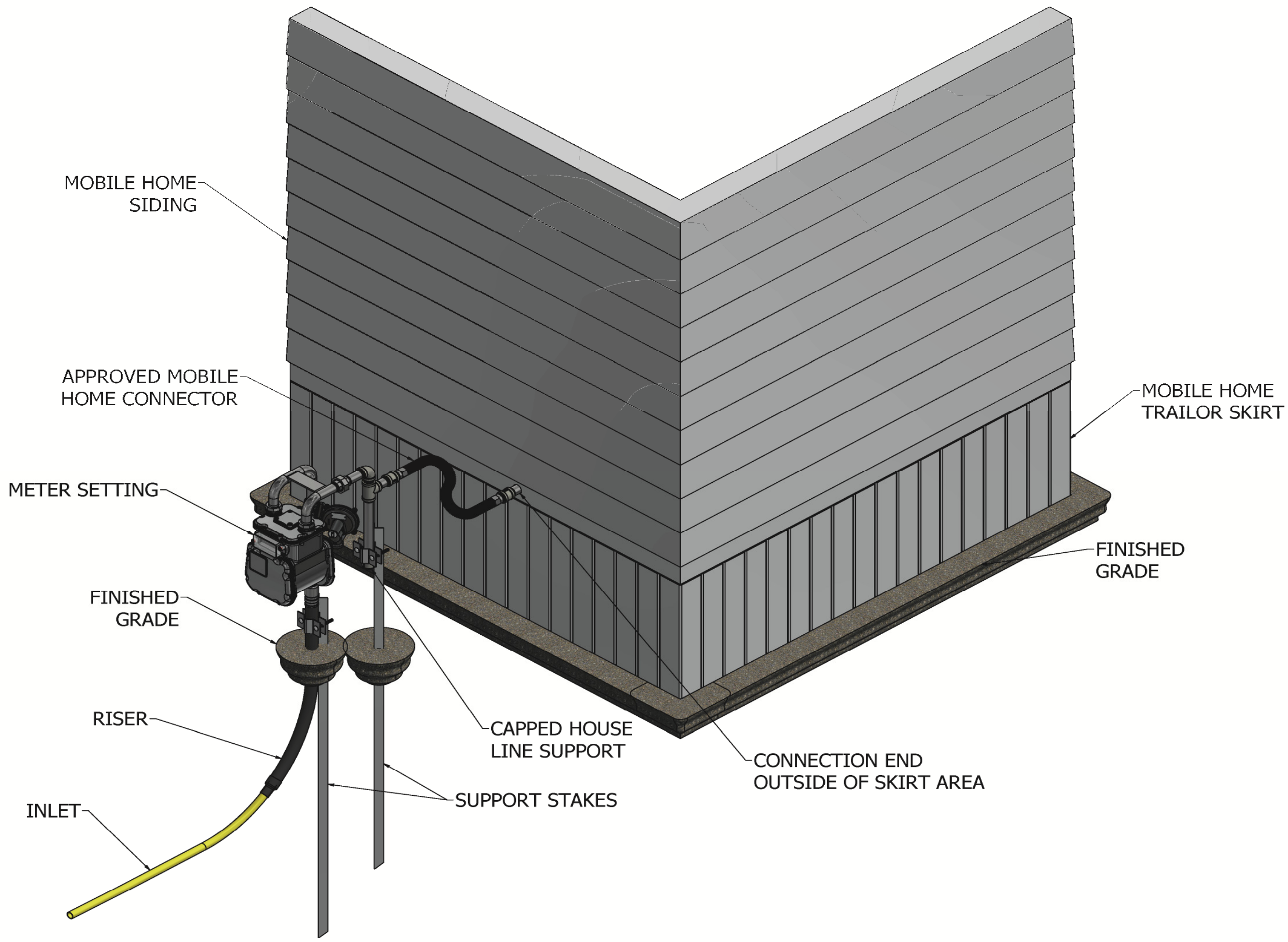
Sketch No. 7 - Sleeves for Masonry Wall Entrances



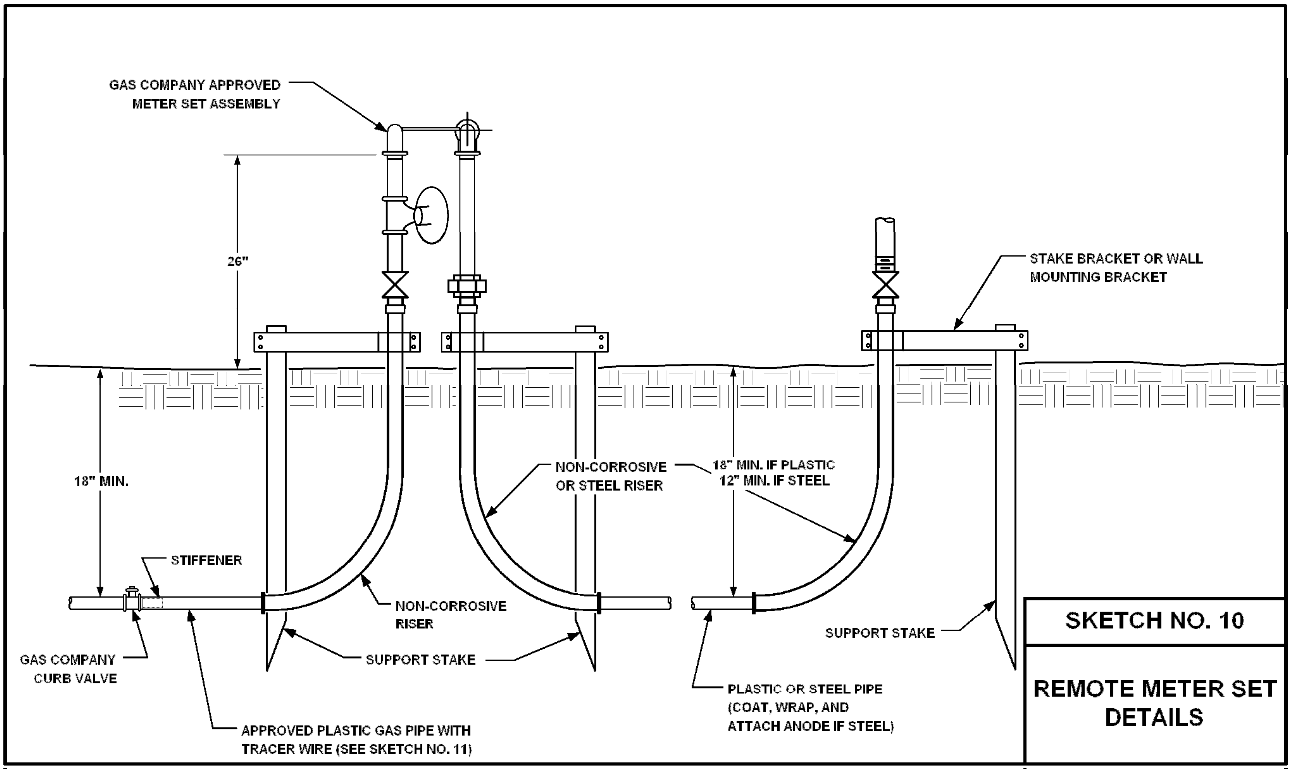
Sketch No. 8 - Prefabricated Masonry Wall Entrances



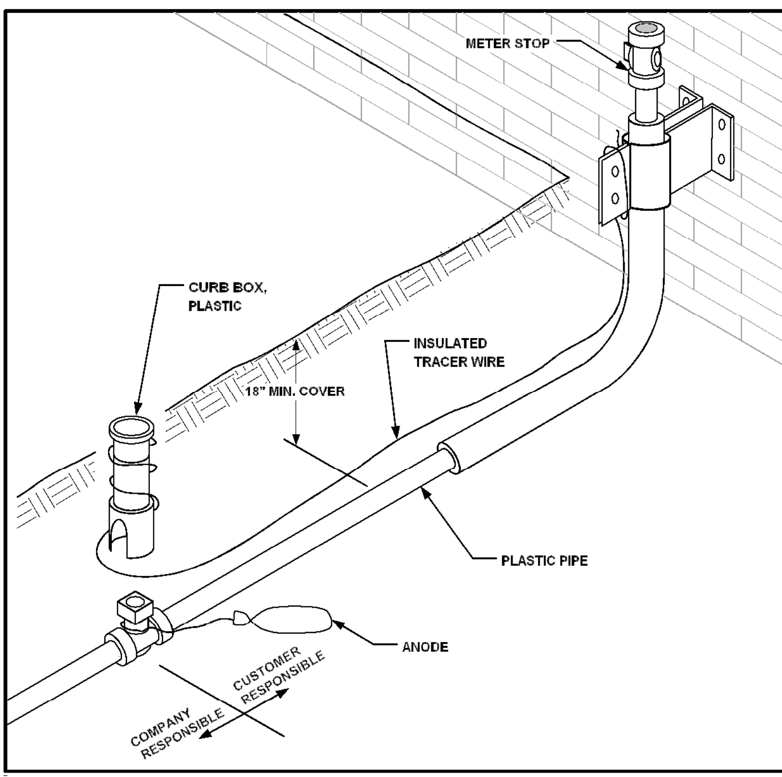
Sketch No. 9 - Mobile Home Installations



Sketch No. 10 - Remote Meter Set Details



Sketch No. 11 - Tracer Wire Details

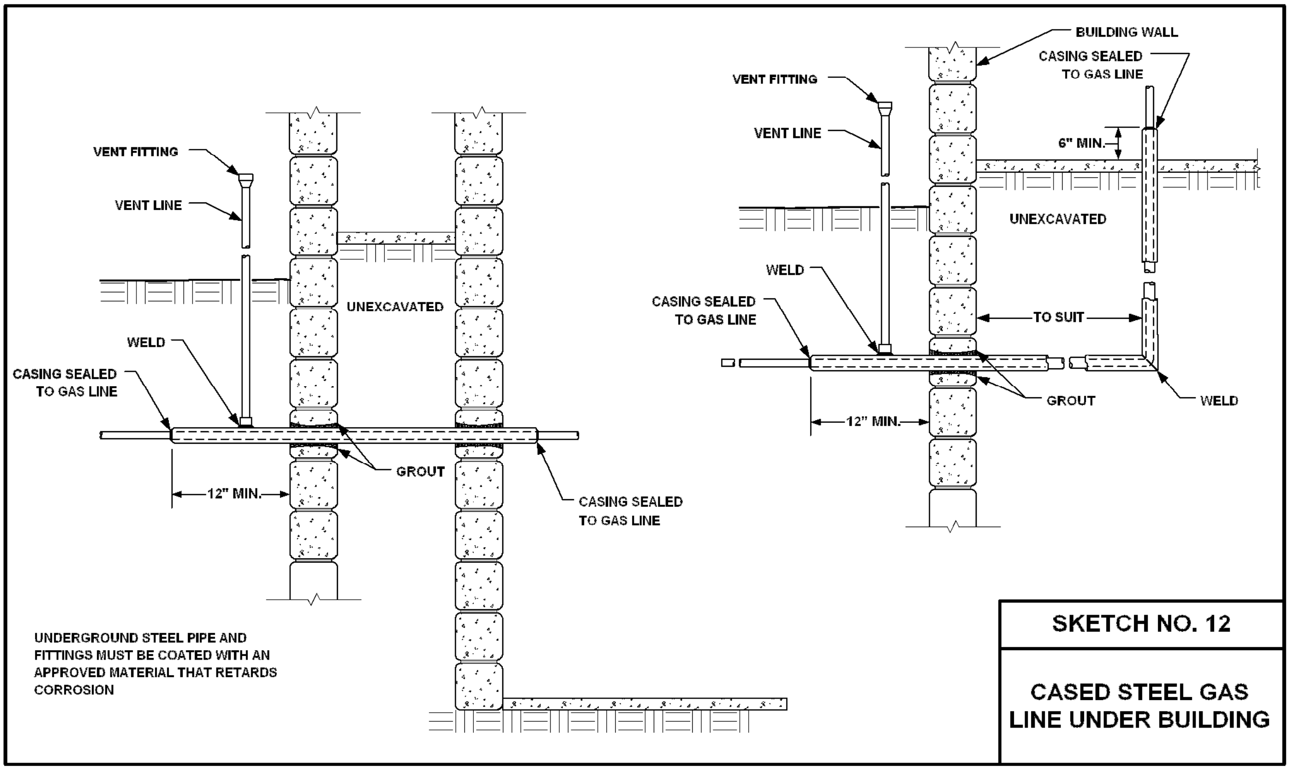


NOTES:
1. BRING INSULATED WIRE ABOVE GRADE AND WRAP AROUND BRACKET.
2. ALLOW SUFFICIENT INSULATED WIRE TO WRAP AROUND OUTSIDE OF CURB BOX AND TO ENTER CURB BOX BELOW LID.
3. WIRE SHALL NOT BE WRAPPED AROUND PLASTIC PIPE, AND CONTACT SHOULD BE MINIMIZED.

SKETCH NO. 11

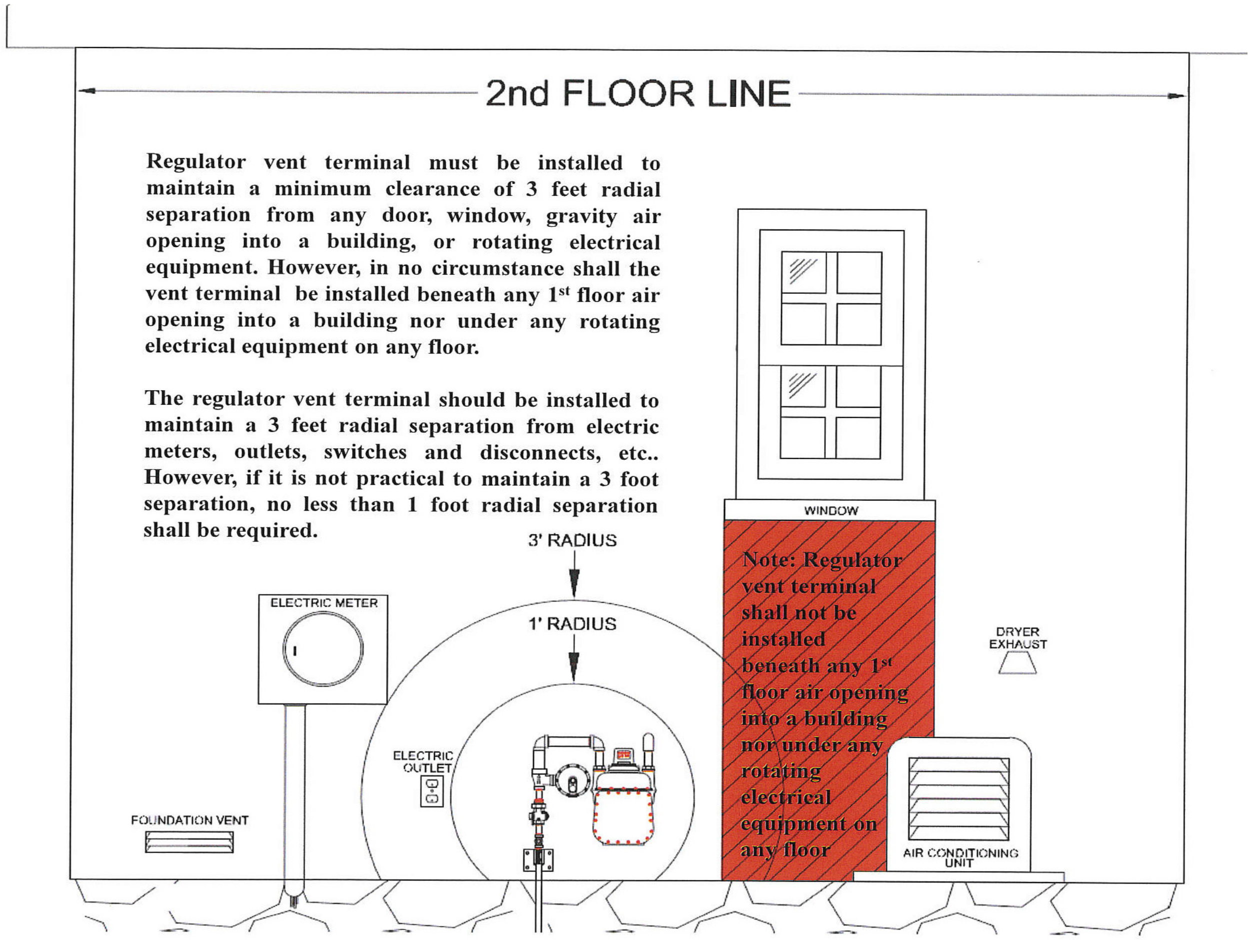
TRACER WIRE DETAILS

Sketch No. 12 - Cased Steel Gas Line Laid Under Building

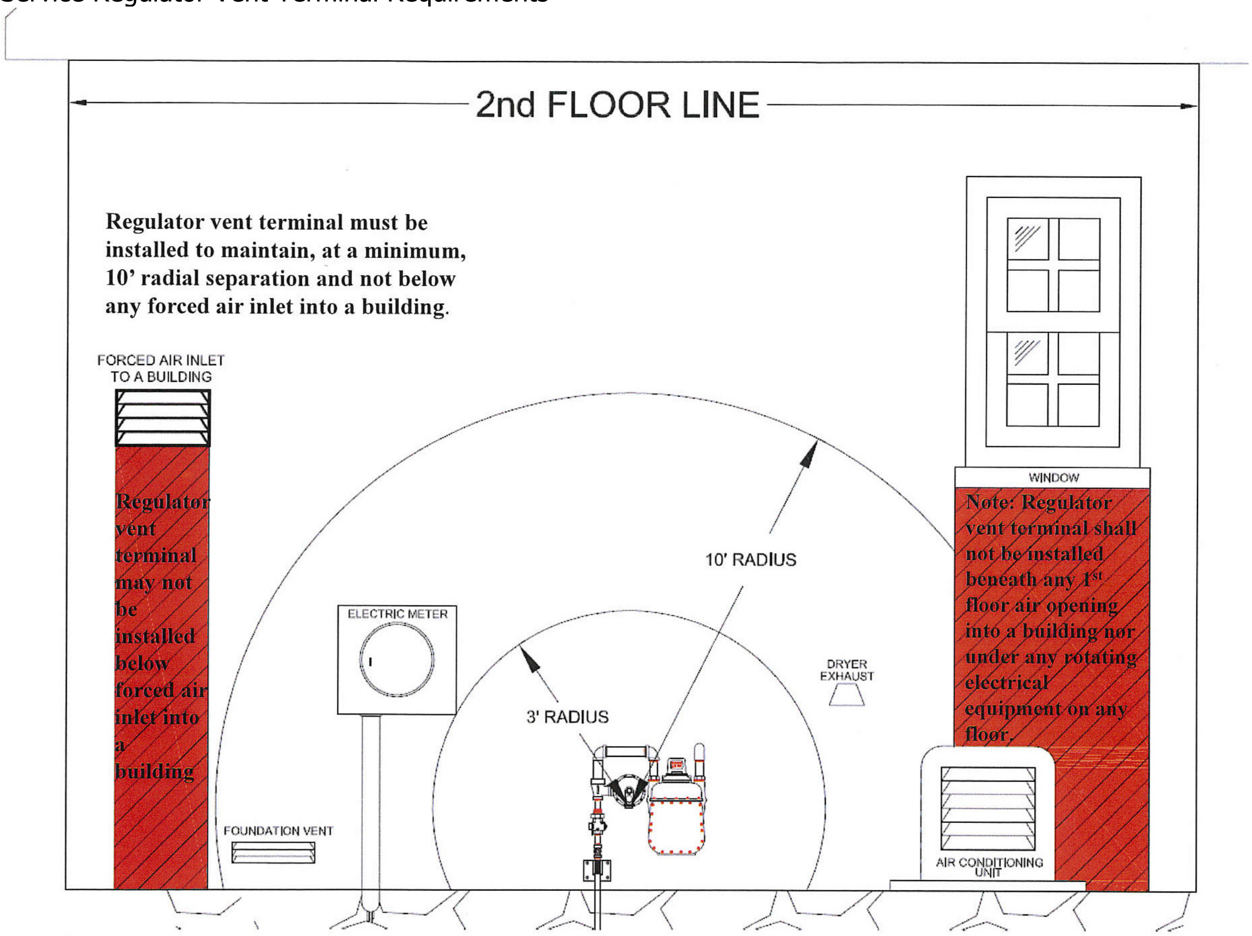


APPENDIX E – SERVICE REGULATOR VENT TERMINAL REQUIREMENTS

Service Regulator Vent Terminal Requirements



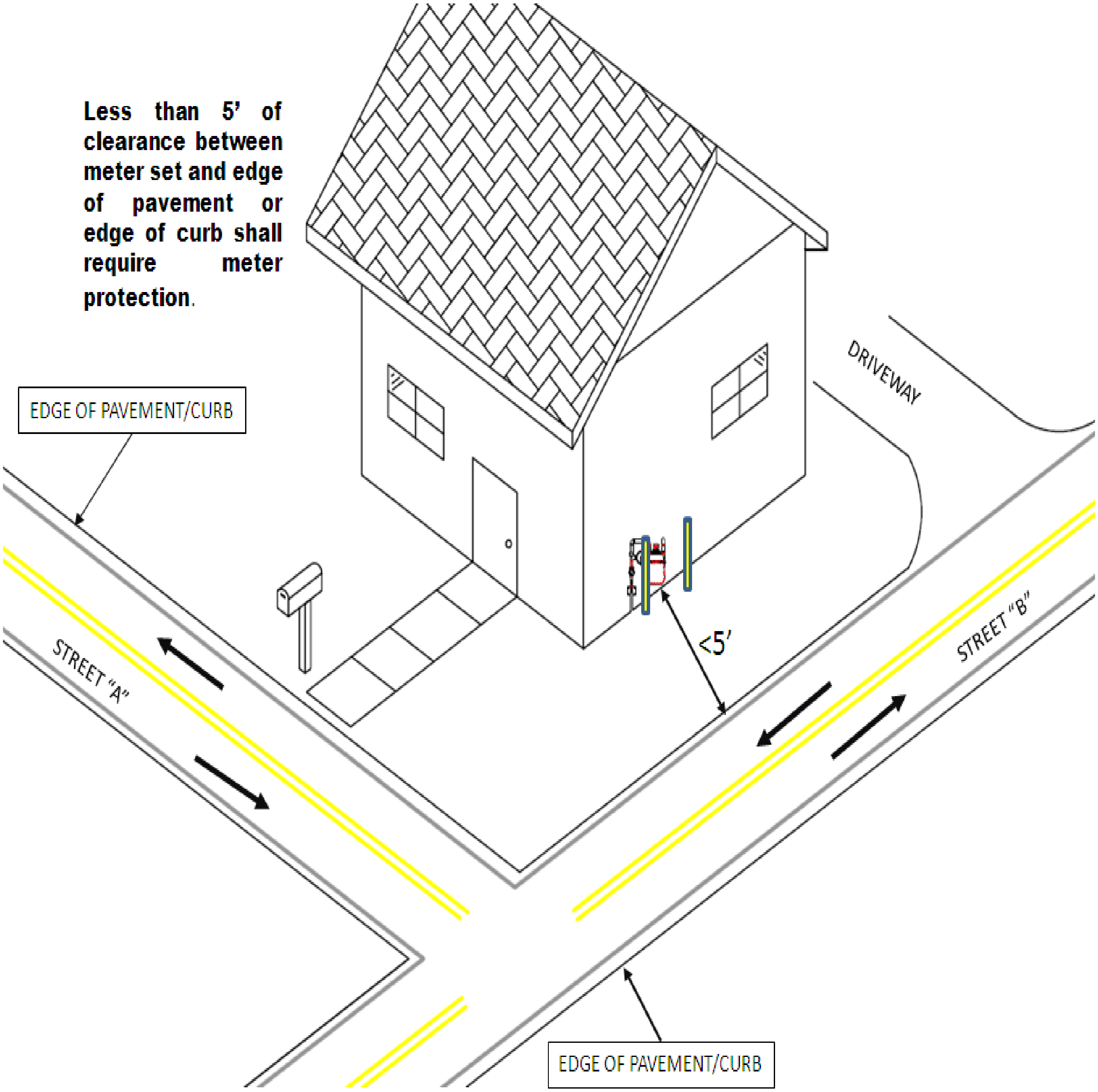
Service Regulator Vent Terminal Requirements



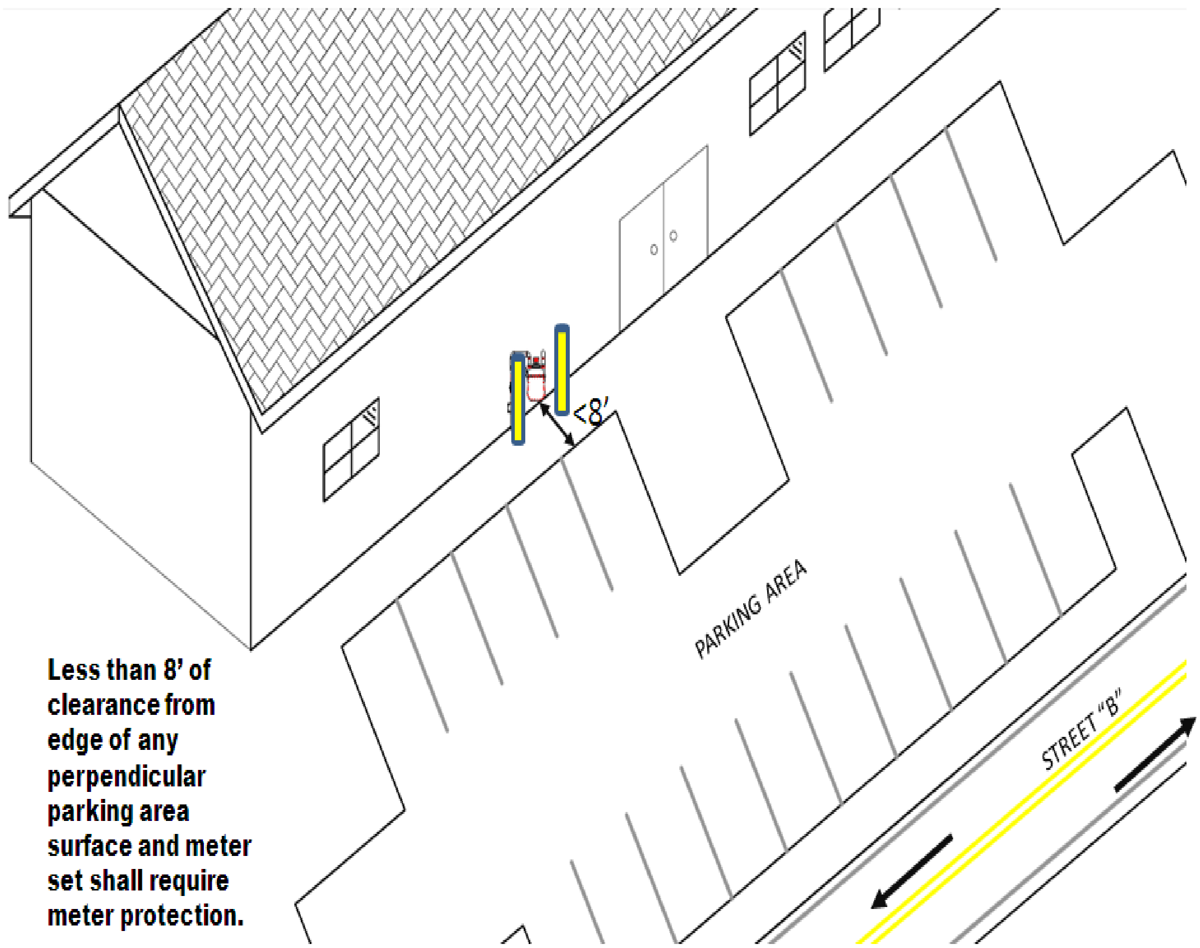
APPENDIX F – Meter Set Assembly Protection

Meter Set Assembly Protection

Less than 5' of clearance between meter set and edge of pavement or edge of curb shall require meter protection.

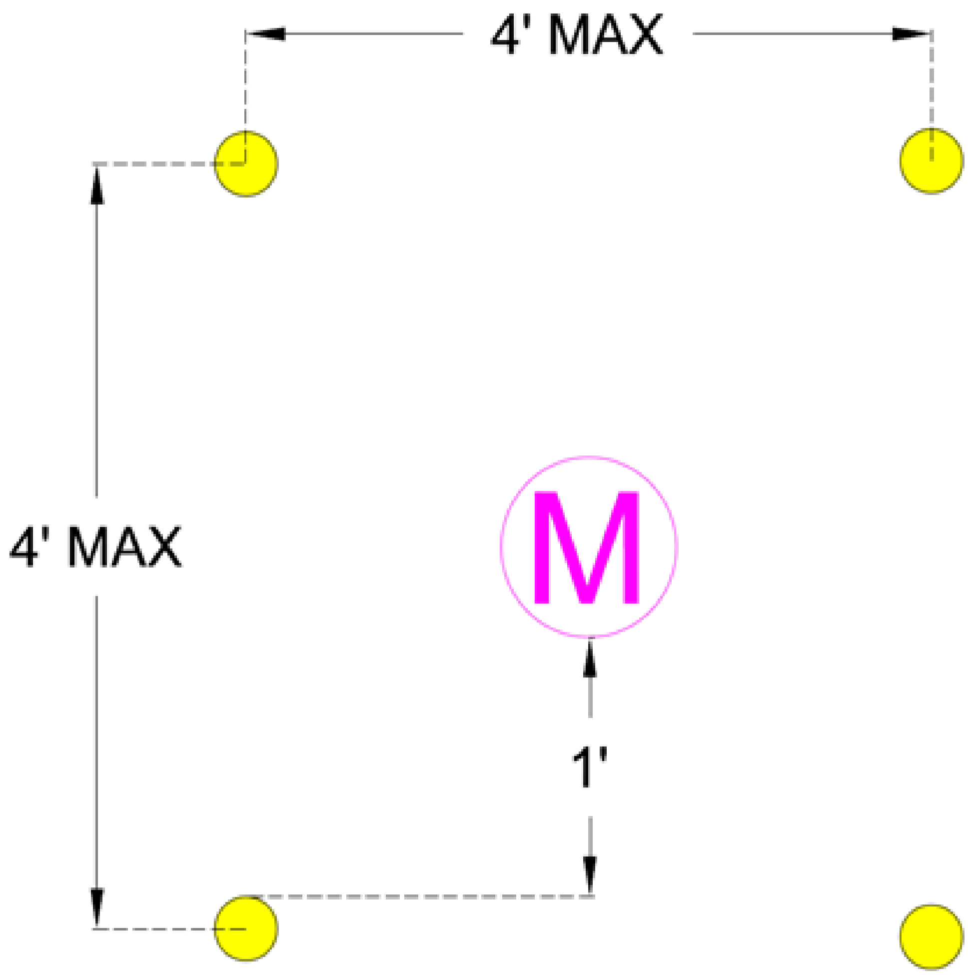


Meter Set Assembly Protection



Meter Set Assembly Protection

Typical Remote Meter Set



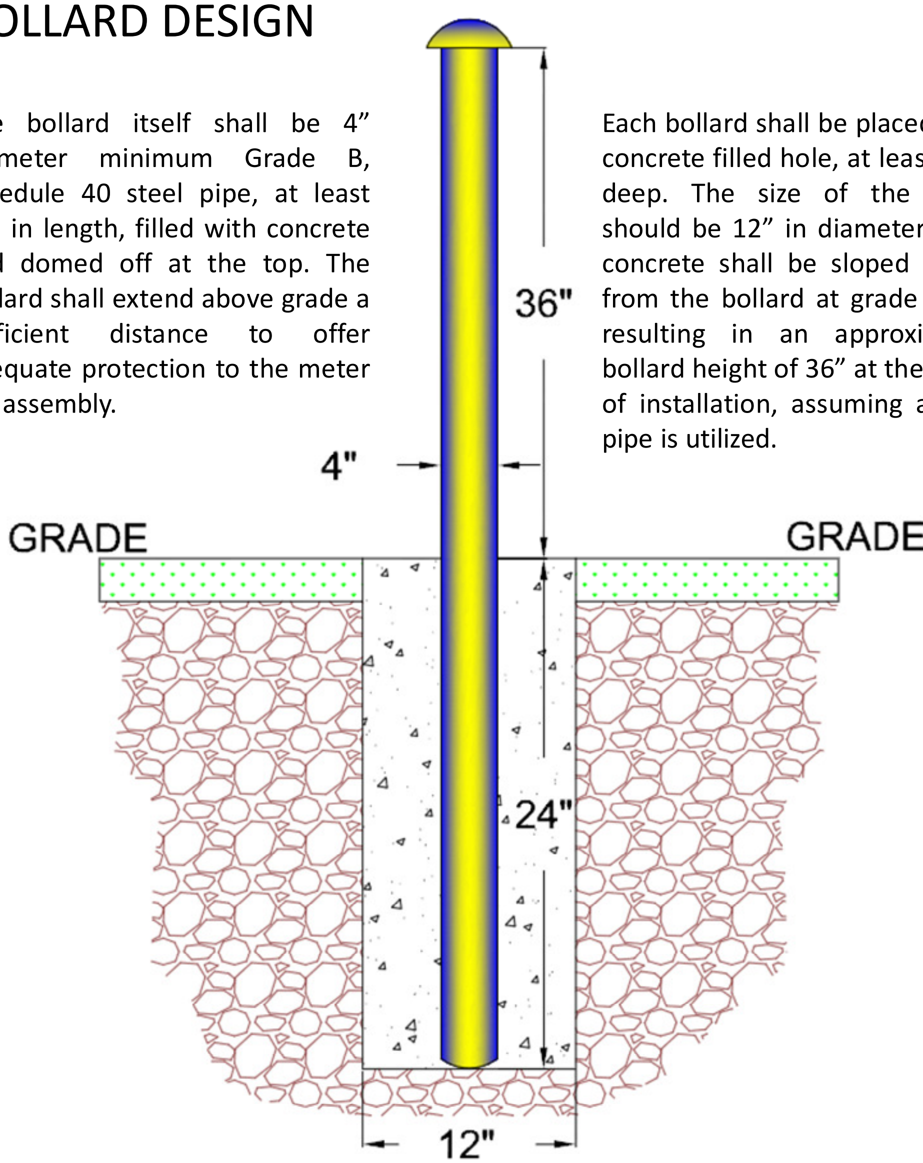
NOTE: Actual site location will dictate if bollards need to be spaced closer than 4’ apart (e.g., farm field or wooded area where snowmobiles or all-terrain vehicle may be anticipated in the area.)

Meter Set Assembly Protection

STANDARD BOLLARD DESIGN

The bollard itself shall be 4” diameter minimum Grade B, schedule 40 steel pipe, at least 60” in length, filled with concrete and domed off at the top. The bollard shall extend above grade a sufficient distance to offer adequate protection to the meter set assembly.

Each bollard shall be placed in a concrete filled hole, at least 24” deep. The size of the hole should be 12” in diameter. The concrete shall be sloped away from the bollard at grade level resulting in an approximate bollard height of 36” at the time of installation, assuming a 60” pipe is utilized.



APPENDIX G - Forms

Form 1 – C-3363, "Operator Qualification Card"

Operator Qualification Card

Please **PRINT CLEARLY** (Contractor must complete all information on top portion only)

Name: ____

Employer (or) Company Name: ______________________________

Qualifying Agency: ______________________________________

Qualification ID# : ☐☐☐☐☐☐☐☐☐☐☐☐

Job Address (Include City) _________________________________

Operator Qualification Work Performed by Person Above

Service Line ○ New Installation ○ Renewal ○ Repair / Other

Meter Setting ○ New Installation ○ Renewal ○ Repair / Modification / Relocation

I attest that all work performed and materials used fully comply with all Federal, State, and Local rules, regulations, codes and standards, and all applicable Columbia Gas Policies and Procedures, regulations, and standards, including, but not limited to: 49 CFR 192, Subpart N; Standards for Customer Service Lines, Meters, and Regulators; Tariffs; and Approved Materials for Gas Piping on Customer Owned Service Lines. I further attest that I am enrolled in a Drug and Alcohol plan in accordance with 49 CFR 199. I understand and agree that Columbia's acceptance of a Qualifier's written program shall in no way constitute an assumption or acceptance by Columbia Gas of responsibility for the installation or repair work performed by me, and I remain responsible for any work performed.

Signature: ______________________________ **Date:** ____/____/____

Note: Operator Qualification Cards can be printed from: www.columbiagasohio.com/business/plumbers or www.columbiagaspamd.com/products_services/plumber_information.htm

Form C – 3363 (11/04)

Information Below - For Columbia Use Only

PSID: ☐☐☐ ☐☐☐ ☐☐☐ **SEQ:** ☐☐

☐ **No Gas Service Established**

(Columbia Action Required)

○ Curb valve - Leaks through or out; Requested stop change

○ Other ____

(Contractor Requirement(s) that Failed)

○ **Qualifications not valid and/or OQ card completion unacceptable***

○ **Unable to visual service line where required***

○ **Service Line / Meter Setting installation violation(s) ***

○ **Service Line / Meter Setting failed pressure test(s) ***

○ Service Line / Meter Setting required clearances not met

○ Non OQ related problem(s)

Name (*print*) ______________________________ **Date:** ___/___/___

*Note: Selections indicated in *BOLD* require card collection - Leave blank OQ replacement card

☐ **Established Gas Service**

Name (*print*) ____________________ **Date card picked up:** ___/___/___

Important

Proper Completion Requirements!

- Card must have all contractor information (top portion) properly filled out. *Please note: You may enter data into each required field prior to printing.*
- Card must be legible.
- Card may not have the signature electronically duplicated.
- Card must be protected from the elements such as rain, frost, snow, etc.
- All applicable qualification work performed by an individual on a meter setting and/or service line must be marked. Blacken or make a distinctive checkmark in appropriate circle(s).
- All individuals, not just the crew leader, who are performing qualification work on a meter setting and/or service line, and who are not directly observed by a qualified individual, must leave a properly filled out Operator Qualification card.

WARNING!

Fraudulent or misuse of cards may ultimately lead to an individual or company being banned from working on Customer owned facilities in Columbia Gas of Ohio's or Columbia Gas of Pennsylvania's service areas.

INDEX

In addition to the Index, refer to the Definitions section for more information.

MANAGEMENT AND OPERATIONS AUDIT

COLUMBIA GAS OF PENNSYLVANIA, INC.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
BUREAU OF AUDITS
ISSUED JUNE 2020

Docket No. D-2019-3011582

COLUMBIA GAS OF PENNSYLVANIA, INC.
MANAGEMENT AND OPERATIONS AUDIT

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LIST OF EXHIBITS

COLUMBIA GAS OF PENNSYLVANIA, INC.

I. INTRODUCTION

In accordance with the Pennsylvania Public Utility Commission's (PUC or Commission) program to identify improvements in the management and operations of fixed utilities under its jurisdiction, it was determined that a management and operations audit should be conducted of Columbia Gas of Pennsylvania, Inc. (CPA or company). Management and operational audits are required of certain utility companies pursuant to 66 Pa. C.S. § 516(a) and fall under the Commission's general administrative power and authority to supervise and regulate all public utilities in the Commonwealth, 66 Pa. C.S. § 501(b). Specifically, the Commission can investigate and examine the condition and management of any public utility, 66 Pa. C.S. § 331(a).

This report summarizes the work of the PUC's Management Audit Division and outlines its conclusions. The findings presented in the report identify areas and aspects where weaknesses or deficiencies exist. In all cases, recommendations are offered to improve, correct, or eliminate these conditions. The final, and most important step, in the management audit process is to initiate actions toward implementation of the recommendations.

A. Objectives and Scope

The objectives of this management and operations audit were:

- to provide the Commission, CPA, and the public with an assessment of the efficiency and effectiveness of the company's operations, management methods, organization, practices, and procedures;
- to identify opportunities for improvement and develop recommendations to address those opportunities; and,
- to provide an information base for future regulatory and other inquiries into CPA's management and operations.

The scope of this audit was limited to certain functional areas within CPA as explained in Section B, Audit Approach.

B. Audit Approach

The management and operations audit was performed by the Management Audit Division of the PUC's Bureau of Audits (auditors). The process began with a pre-fieldwork analysis as outlined below:

- A five-year internal trend (2014-2018) and ratio analysis was completed using financial and operational data obtained from CPA, the Commission, and other available sources.

- Input was solicited from PUC bureaus and offices, external parties, and CPA regarding any concerns or issues they would like addressed during our review.

- Prior management and operations audits, follow-up management efficiency investigations, implementation plans, implementation plan progress reports, other Commission conducted audits, annual diversity reports, and other available documents were reviewed.

This information was used to focus the auditors' work efforts. Specifically, the listed functional areas were selected for in-depth analysis and are included in this report:

- Executive Management and Organizational Structure
- Corporate Governance
- Affiliated Interests and Cost Allocations
- Financial Management
- Gas Operations
- Customer Service
- Purchasing and Materials Management
- Emergency Preparedness
- Human Resources
- Fleet Management
- Information Technology

The pre-fieldwork analysis should not be construed as a comprehensive evaluation of the management or operations in the functional areas not selected for in-depth examination. Had we conducted a thorough review of those areas, weaknesses or deficiencies may have come to our attention that were not identified in the limited pre-fieldwork review.

Fieldwork began on September 16, 2019 and continued intermittently through January 29, 2020. The principal components of the fact gathering process included:

- interviews with CPA personnel as well as other Commission bureaus;

- analysis of records, documents, and reports of a financial and operational nature focused primarily on the period 2014-2018, and the year 2019, as available; and,

- visits to CPA's Headquarters in Canonsburg, Pennsylvania, the Smithfield Customer Care Center, select local operations and training centers, select NiSource Corporate Services Company offices in Columbus, Ohio, and observation of several other selected work practices.

C. Functional Area Ratings

For the functional areas selected for in-depth examination, the auditors rated the operating or performance level relative to the expected performance level at the time of the audit. This expected performance level is the state at which each functional area should be operating given the company's resources and general operating environment. Expected performance is not a "cutting edge" operating condition; rather, it is management of a functional area such that it produces reasonably expected operating results.

Listed below are the evaluative categories used to rate each functional area's operating or performance level:

- Meets Expected Performance Level
- Minor Improvement Necessary
- Moderate Improvement Necessary
- Significant Improvement Necessary
- Major Improvement Necessary

Our ratings for each reviewed functional area can be found in Exhibit I – 1 on the next page.

Exhibit I – 1
Columbia Gas of Pennsylvania, Inc.
Management and Operations Audit
Functional Area 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				
Customer Service			X		
Purchasing and Materials Management	X				
Emergency Preparedness	X				
Human Resources		X			
Fleet Management		X			
Information Technology	X				

D. Benefits

Where possible, the auditors estimated the potential savings expected from implementing the recommendations made in this report. The audit report contains potential cost savings of $272,000 to $332,000, annually. We tried to identify, whenever practical, the potential savings, net of the projected costs, for implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues; whereas, others would result in 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, actual benefits from effective implementation of the recommendations are subject to uncertainty and could be higher or lower than the estimate. An overall summary of the annual and one-time costs savings quantified in the audit report are shown in Exhibit I – 2 on the next page.

Exhibit I – 2
Columbia Gas of Pennsylvania, Inc.
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Implement various strategies to reduce arrearage levels such as increasing CAP enrollment and effective calculation of internal arrearage data to appropriately monitor and manage arrearage performance. (VIII – 2)	$92,000	
Complete an analysis of the third-party retention application to evaluate program efficacy in reducing CSR turnover rates by December 31, 2020. (VIII – 5)	$180,000 - $240,000	
Total	**$272,000 - $332,000**	**-**

For most of the recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was 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 nor was not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

CPA will have options to implement the recommendations and, as a result, the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Recommendation Summary

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

- INITIATION – Estimated time frame for how quickly CPA should be able to initiate its implementation efforts given CPA's resources and general operating environment. The time necessary to complete implementation will vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to implement the recommendation.

- BENEFITS – Net quantifiable benefits are provided, where they could be estimated, as discussed in Section D – Benefits. Our estimated overall level of benefit rankings is not solely based on quantifiable dollars but considers the auditors' assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of CPA and/or the services it provides.

  - HIGH BENEFIT – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

  - MEDIUM BENEFIT – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

  - LOW BENEFIT – Implementation of the recommendation is likely to result in service improvements, improvements in management practices and performance, and/or enhanced cost controls.

Columbia Gas of Pennsylvania, Inc.
Summary of Recommendations

Rec. No.	Recommendation	Page No.	Initiation Time Frame	Benefits (including $ estimate)
Chapter III – Executive Management and Organizational Structure				
III – 1	Perform and retain documentation of span of control analysis upon completion of the reorganization at year-end 2020.	16	Within 1 year	Low
III – 2	Analyze processes where data is being reported on by a different group than those responsible for the business activities to ensure that appropriate levels of communication and review are maintained.	16	6 months	Medium
Chapter IV – Corporate Governance				
IV – 1	Formally record and retain minutes of all NGD and CPA management committee meetings during which corporate governance activities are performed. Alternatively, establish an Executive Committee for the NGD and CPA Boards of Directors, respectively, which would record and retain meeting minutes.	20	3 – 6 months	Low
Chapter V – Affiliated Interests and Cost Allocations				
V – 1	Develop and implement controls to ensure that borrowing activities comply with regulatory approvals and notification requirements.	28	3 months	Medium
V – 2	Develop and implement a review schedule to regularly update the NCSC CAM consulting the NARUC Guidelines for Cost Allocations and Affiliate Transactions.	28	3 months	Medium
V – 3	Review and strengthen internal control subsequent to the NCSC accounting function reorganization.	28	3 months	Medium
V – 4	Develop and implement cost allocation training for employees subsequent to the review and update of the CAM.	28	6 months	Medium
Chapter VI – Financial Management				
VI – 1	Revise the Dividend Policy to provide advance notice, including explanation of rationale, to the Commission whenever a dividend payment would exceed 85% of net income.	38	3 months	Low
VI – 2	Include an O&M budget variance section that requires documented explanations when budget variances fall outside of defined variance tolerance levels in the O&M Policy.	38	3 months	Low
VI – 3	Update the delegation of authority table to include approval levels for internal transactions.	39	3 months	Medium

Columbia Gas of Pennsylvania, Inc.
Summary of Recommendations

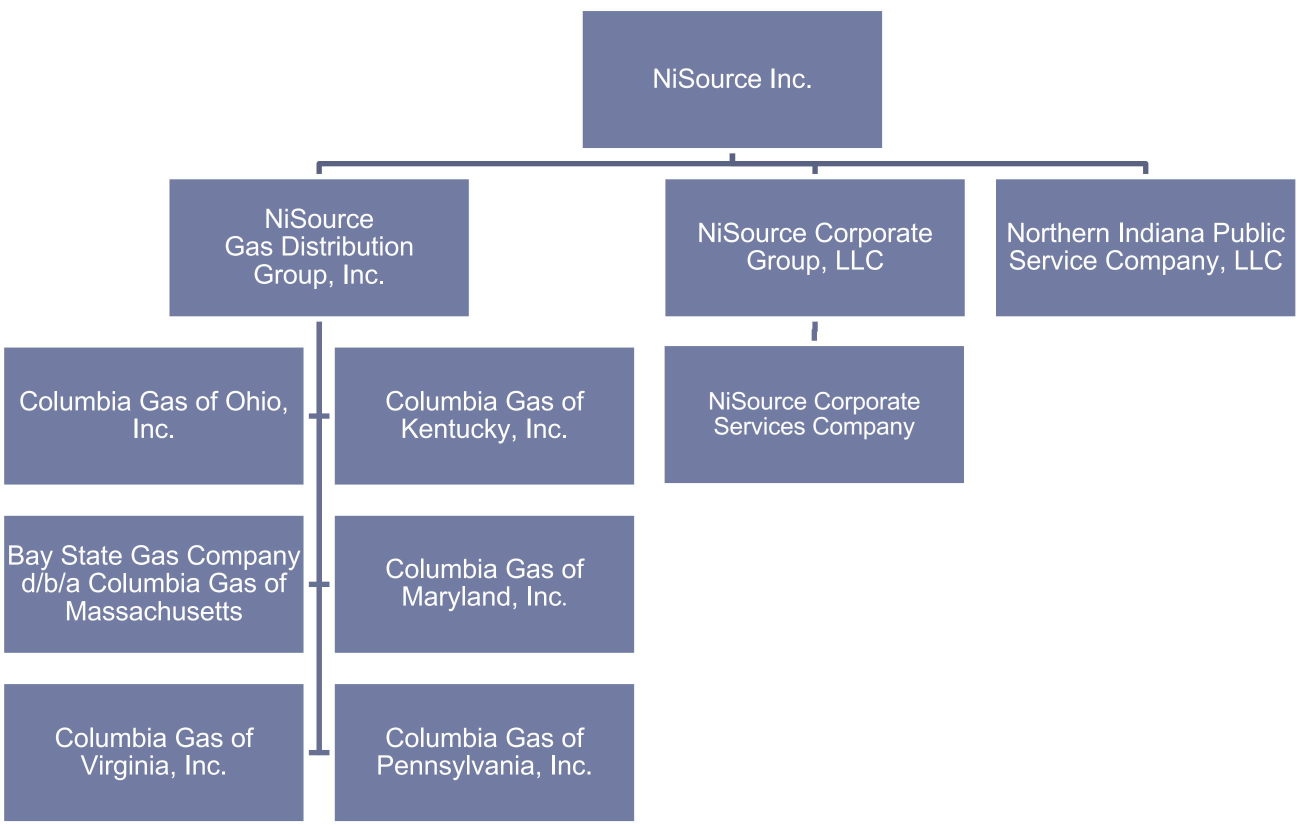
Rec. No.	Recommendation	Page No.	Initiation Time Frame	Benefits (including $ estimate)
Chapter VI – Financial Management (Continued)				
VI – 4	Revise the Treasury Operations Payment Guidelines, the O&M Policy, the Delegation of Authority Table, and Cash Collections Policy to include a responsibility and scope section.	39	3 months	Low
Chapter VII – Gas Operations				
	None	---	---	---
Chapter VIII – Customer Service				
VIII – 1	Develop and implement a review schedule to ensure the metering and billing policies and procedures are kept current.	59	3 months	Low
VIII – 2	Implement various strategies to reduce arrearage levels such as increasing CAP enrollment and effective calculation of internal arrearage data to appropriately monitor and manage arrearage performance.	59	9 months	High $92,000 Annual Savings
VIII – 3	Develop and implement net collection goals with which to manage third-party collection efforts by benchmarking with similar utilities.	59	6 months	Medium
VIII – 4	Develop and implement a documented TOS program.	59	3 months	Low
VIII – 5	Complete an analysis of the third-party retention application to evaluate program efficacy in reducing CSR turnover rates by December 31, 2020.	59	9 months	High $180,000-$240,000 Annual Savings
Chapter IX – Purchasing and Materials Management				
	None	---	---	---
Chapter X – Emergency Preparedness				
	None	---	---	---
Chapter XI – Human Resources				
XI – 1	Analyze influencing factors when developing future safety performance targets to ensure goals are set at challenging, attainable levels while continuing to prioritize the safety culture to bolster continuous improvement toward long-term safety performance goals.	73	6 – 9 months	Low
Chapter XII – Fleet Management				
XII – 1	Develop and regularly review a historical summary report of annual vehicle utilization data to ensure optimal fleet efficiency.	76	3 months	Low
Chapter XIII – Information Technology				
	None	---	---	---

II. Background

Columbia Gas of Pennsylvania, Inc. (CPA or company) is a subsidiary of NiSource Gas Distribution Group, Inc. (NGD), which is owned by the energy holding company, NiSource Inc. An organization the size and complexity of NiSource Inc. is continuously developing and evolving; however, beginning in 2015, it has been initiating major restructuring efforts relative to both the corporate structure and to the reorganization of the remaining core regulated utility business focused on electric transmission and distribution and natural gas distribution.

On July 1, 2015, NiSource Inc. separated from its former interstate pipeline subsidiaries, Columbia Transmission Company and Columbia Gulf, creating two separate entities, NiSource Inc. and Columbia Pipeline Group Inc. TransCanada PipeLine USA Ltd acquired all shares of Columbia Pipeline Group Inc. and it is no longer affiliated with NiSource Inc. NiSource Inc. currently has three direct subsidiaries and those subsidiaries have twenty-one additional subsidiaries. Exhibit II – 1 shows NiSource Inc.'s corporate structure.

Exhibit II – 1
NiSource Inc. Corporate Structure
As of September 30, 2019



Source: Data Request EM-23

As mentioned earlier, CPA is a subsidiary of NGD. NGD is the holding company for six of the seven natural gas distribution companies ultimately owned by NiSource Inc. Northern Indiana Public Service Company, LLC (NIPSCO) is a combined electric and gas utility. Within NIPSCO are an electric public utility transmission provider, a retail electric service provider, wholesale power trading operations, and the remaining natural gas distribution company. Although NIPSCO holds ownership of the seventh natural gas distribution company, it is managed with the other six natural gas distribution companies through the Gas Segment. The other entities of NIPSCO make up the Electric Segment. NiSource Corporate Services Company (NCSC) provides many shared services to the entities of the corporation. More information about the shared services provided by NCSC as well as the routine transactions between the NiSource Inc. subsidiaries is provided in Chapter V – Affiliated Interests and Cost Allocations.

NiSource Inc.'s natural gas distribution operations serve more than 3.5 million customers in seven states and operate approximately 60,000 miles of pipeline. NiSource Inc.'s 2019 consolidated operating revenue totaled $5.2 billion of which $3.5 billion resulted from natural gas distribution operations. CPA's 2019 operating revenue totaled $602 million which accounted for 17.2% of the Gas Segment operating revenue and 11.6% of total consolidated NiSource Inc. operating revenue.

As of the year-ended December 31, 2019, CPA had 436,595 total sales and transportation customers serviced by approximately 8,000 miles of pipeline. CPA's customers were comprised of 399,076 residential, 37,254 commercial, and 265 industrial customers. Gas sales statistics for each customer class are presented in Exhibit II – 2.

Exhibit II – 2
Columbia Gas of Pennsylvania, Inc.
Gas Sales Statistics by Customer Classification
For the Year Ended December 31, 2019

Customer Class	# of Sales Customers	% of Customers	MCF Sold	% of MCF Sold	Revenue	% of Revenue
Residential	399,076	91.4%	32,642,666	41.3%	$443,641,575	73.8%
Commercial	37,254	8.5%	23,536,207	29.8%	$133,446,660	22.2%
Industrial	265	0.1%	22,786,533	28.9%	$24,143,948	4.0%
Totals	**436,595**	**100.0%**	**78,965,406**	**100.0%**	**$601,232,183**	**100.0%**

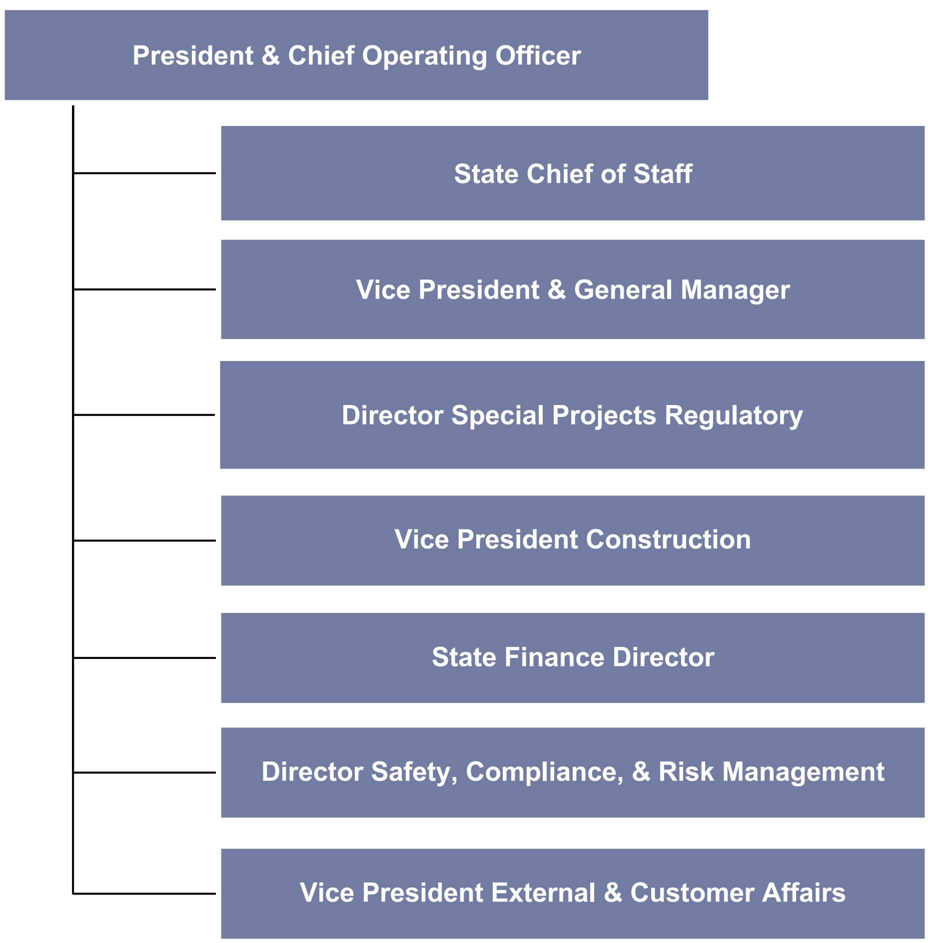
Source: CPA's 2019 Annual Report to the Pennsylvania Public Utility Commission and Auditor Analysis

III. EXECUTIVE MANAGMENT AND ORGANIZATIONAL STRUCTURE

Background

As discussed in Chapter II – Background, Columbia Gas of Pennsylvania, Inc. (CPA or company) is a subsidiary of NiSource Gas Distribution Group, Inc. (NGD) which is owned by the energy holding company, NiSource Inc. CPA and Columbia Gas of Maryland (CMD) are managed by the same executive team and share the headquarters office located in Canonsburg, Pennsylvania. The organizational structure of CPA's executive team is shown below in Exhibit III – 1. CPA's President & Chief Operations Officer (COO) reports to the Executive Vice President & President, Gas Utilities who oversees NGD which is also known as the Gas Segment.

Exhibit III – 1
Columbia Gas of Pennsylvania, Inc.
Executive Team Organization
As of December 2019



Source: Data Request EM-29

The executive team structure as presented in Exhibit III – 1 is the result of reorganization efforts beginning in 2018. Prior to reorganization, field operations, as well as construction and safety were centralized under corporate shared services. Currently, the responsibilities of these functions have shifted to local state gas distribution company executive teams to ensure authority and accountability are closer to the work being done.

Although there were many similarities among the different local state gas distribution companies, there were unique differences such as identified risks, work priority due to the natural and regulatory environment, and customer expectations that motivated this strategic change. Cross functional teams within the Gas Segment, composed of leaders, subject matter experts, and other business partners, will continue to provide centralized support of these functional areas to help maintain optimal standards and drive best practices. In addition, this structure supports the Safety Management System (SMS) operating model NiSource Inc. initiated in 2015. More information about the SMS is provided in Chapter XI – Human Resources. The roles and responsibilities of the executive team are as follows:

- **President & COO** – works with the NGD executive team to develop the strategic plan and corresponding business activities and goals and monitors the successful execution of the overall operation of CPA and CMD gas distribution companies; prior to reorganization, this role was primarily focused on the financial and regulatory management responsibilities of the local state gas distribution company

- **State Chief of Staff**[1] – enables the success of CPA/CMD's leadership team as a strategic partner and trusted advisor of the President & COO; newly created position post reorganization

- **Vice President & General Manager** – leads CPA/CMD's field operations function in its execution of the delivery of safe, reliable, efficient natural gas distribution; role decentralized to focus on local state initiatives post reorganization

- **Director Special Projects Regulatory** – oversees the timely completion of special projects in the communications, community relations, regulatory, and legislative functions of CPA/CMD to achieve a positive external and internal environment so that financial and non-financial business objectives can be realized; role redefined post reorganization

- **Vice President Construction** – leads CPA/CMD's construction operations function in its execution of the delivery of safe, reliable, efficient natural gas distribution with a blanket capital budget of $200 million plus annually; role decentralized to focus on local state initiatives post reorganization

[1] This unique position was added to the organization at the end of audit fieldwork; therefore, the auditors were unable to review this position further during this audit

- **State Finance Director** – analyzes and supports the financial planning, forecasting, and budgeting processes at the local state gas distribution company level; role repositioned post reorganization

- **Director Safety, Compliance, & Risk Management** – provides oversight to assure execution of CPA safety programs; role decentralized to focus on local state initiatives and prioritized to avoid direct influence of the performance pressures of the field operations and construction functions post reorganization

- **Vice President External & Customer Affairs** – develops and executes influence strategies that persuade key stakeholders to take action that will advance shared interest and business goals through the implementation of innovative, customer-centric, and profitable strategies for communications, community relations, municipal relations, and regulatory and external affairs; newly created position post reorganization

Many utility companies' board of directors are the main planning and managerial oversight body; however, within NiSource Inc., the priority focus of the NiSource Inc. Board of Directors (NiSource Inc. Board) is to determine eligible capital to be disbursed between the Electric Segment and the Gas Segment and to maintain the company-wide fiscal and operational excellence that its stockholders expect. It does this by monitoring the Electric Segment's and Gas Segment's achievements toward annual performance measures throughout the year. The NiSource Inc. Board relies on the executive teams of both segments to provide corporate oversight by developing business plans, activities, and remediation actions, when necessary, to reach strategic goals such as prioritizing safety and maintaining excellent customer service while providing reliable and efficient utility service. There are designated executive teams at both the Gas Segment level and the local state gas distribution company level that perform the planning and oversight functions. The structure and activities of each the NiSource Inc. Board and the board of directors of NGD and CPA, respectively, are explained in more detail in Chapter IV – Corporate Governance.

CPA maintains a routine business planning process that begins in April, builds from May through August, and results in the finalization of the following year's operational and financial goals and targets by November. Strategic and financial plan scenarios are clarified which are balanced by risk mitigation mostly guided by the SMS operating model. Corporate, along with Electric Segment and Gas Segment strategies, are reviewed which then allow for the development of specific initiatives and the identification of key metrics and performance indicators.

Every level of employee from top executives through hourly unionized and non-unionized skilled workers participate in the same general compensation program which includes both base pay and incentive pay components. All employees are offered the same benefit options as well. There is a vast array of training available for CPA employees including computer-based curriculum, hands-on and on-the-job training opportunities, and classroom instruction. As employees are developed through training and experience, those with advanced potential and a desire to take on more responsibility are identified within the succession plan managed by NiSource Corporate Services Company. This allows for the varying opportunities that arise within the NiSource Inc. organization to be available to all those working throughout the various subsidiary companies. More detail about compensation, benefits, training, and succession planning is presented in Chapter XI – Human Resources.

Cultural assessment is a routine process within the NiSource Inc. organization. Annual written surveys are administered, and participation is encouraged through full managerial support. Multiple completion and submission formats are available to ensure all employees have the necessary access and comfort to participate in each cultural assessment opportunity. Results are compiled and action steps are prepared to be implemented within the first quarter of each year. Due to the recent major reorganization, the company plans to offer more in-depth cultural assessment processes throughout 2021 which will include interview-style opportunities to ensure employees have a voice relative to the new cultural outcomes. NiSource Inc.'s current cultural priorities are a revitalized commitment to safety, a focus on customer-centric perceptions and value, and a concentration on employee experience to be recognized among the best places to work.

Findings and Conclusions

Our examination of the executive management functional area included a review of executive team organizational structure, planning and performance management, executive compensation; development; and succession planning, corporate culture, and span of control. Based on our review, NiSource Inc. and its subsidiaries should devote additional effort to improving the efficiency and/or effectiveness of the executive management functional area by addressing the following:

1. A span of control analysis would be beneficial upon completion of Columbia Gas of Pennsylvania's reorganization.

Span of control refers to the number of subordinates each manager or supervisor directly supervises throughout an organization. Factors affecting span of control include:

- nature of work,
- similarity of work functions,
- control practices maintained,
- geographic proximity,
- necessary degree of supervisory coordination,
- operational assistance available for delegation,
- effectiveness of communication,
- capacity of subordinates,
- ability of executives, and
- time available for supervision.

To maximize organizational efficiency and effectiveness, a company should ideally aim for span of control ranges of 1:4 to 1:9. Overly narrow spans of control are considered inefficient typically resulting in micro-management, excess supervision, and higher than necessary compensation costs. Excessively wide spans of control can result in poor performance due to the lack of effective management oversight and control.

There are situations which may warrant a span of control outside of the ideal ranges. For example, complex processes may require management of a function as opposed to managing employees (i.e., low span of control), while other highly repetitive work tasks, routinely performed by larger pools of employees, may be well managed within higher spans of control.

A span of control analysis should be periodically performed to ensure there are effective levels of management oversight in each department and to verify job titles adequately identify and reflect levels of responsibility. Retaining the analysis documentation provides historical data to allow for trending and informed decision making. Proper documentation would include explanations of variances outside established span of control guidelines.

Although NiSource Inc. provides written guidelines relative to organization planning, job titling, and span of control and the NiSource Inc. entities indicate these are routinely reviewed areas, CPA does not maintain documentation of the results of this analysis. NiSource Inc. and its subsidiaries have been in active entity and structure reorganization since 2015. Reorganization is projected to be complete by the end of 2020. A span of control analysis performed prior to completion of reorganization would not be meaningful; however, failure to perform a span of control analysis upon completion could result in supervisory/management levels in misalignment with established span of control guidelines which could further result in inefficiencies and ineffectiveness.

2. There is insufficient communication between those responsible for performing and managing some functional business activities and those reporting on the performance of those functional business activities to both management and regulatory bodies.

The auditors, while conducting interviews with various departments' management and staff throughout audit fieldwork, identified communication deficiencies. Some examples of these communication deficiencies are as follows:

- During an interview with the Director, Safety, Compliance, & Risk Management, it was explained that neither he nor his direct staff gather, review, nor submit the data to the American Gas Association through whom safety metrics such as OSHA Recordable Rate and related metrics are benchmarked with those of like utilities.

- During an interview with management and staff of the Revenue Recovery group, the auditors asked for an explanation of why CPA's average arrearage, as reported to the Pennsylvania Public Utility Commission's Bureau of Consumer Services (BCS) for use within BCS' Universal Service Programs and Collections Performance Report (USP & Collections Report), is higher than the average arrearage of the other natural gas distribution companies compared in the presented panel. The Revenue Recovery personnel were not aware that data was being submitted to BCS nor that the USP & Collections Report reported comparison data of average arrearage which may have contributed to its less rigorous management of arrearage levels as discussed further in Finding and Conclusion No. 2 of Chapter VIII – Customer Service.

- During an interview with the Vice President, Customer Care Centers, it was mentioned that the performance metrics that are monitored by management relative to the Smithfield, PA Customer Care Center (CCC) are set up differently and capture different data from the data gathered and submitted to BCS, and CCC management does not review, nor have a role in, the regulatory reporting activities.

These were several examples encountered by the auditors during audit fieldwork. It is likely that there are other processes experiencing similar disconnect.

Those responsible for reporting on functional business unit performance should communicate with those actively working within the functional business units to ensure that accurate data is being gathered and reported to both management and regulatory bodies. In addition, departmental goals and performance expectations should align with regulatory requirements to ensure that business plans and activities are centered around appropriate outcomes. Each functional business unit should have opportunity and expectation to review data being gathered to report on functional business unit performance as well as to understand the consulted data sources and the data collection methodology being used during performance report preparation.

Recommendations

1. **Perform and retain documentation of span of control analysis upon completion of the reorganization at year-end 2020.**

2. **Analyze processes where data is being reported on by a different group than those responsible for the business activities to ensure that appropriate levels of communication and review are maintained.**

IV. CORPORATE GOVERNANCE

Background

As discussed in Chapter II – Background, Columbia Gas of Pennsylvania, Inc. (CPA or company) is a subsidiary of the NiSource Gas Distribution Group, Inc. (NGD), which is owned by the energy holding company, NiSource Inc. NiSource Inc. is a publicly traded company listed on the New York Stock Exchange (NYSE) under the symbol "NI"; as such, it is subject to the corporate governance requirements contained in both the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley) and the corporate governance rules of the NYSE.

As of December 2019, NiSource Inc. has an eleven-member Board of Directors (NiSource Inc. Board) comprised of the President and Chief Executive Officer (CEO) of NiSource Inc. along with 10 independent board members. The NiSource Inc. Board has adopted independence provisions within its Corporate Governance Guidelines, to assist in ensuring director independence in accordance with NYSE and Securities and Exchange Commission (SEC) requirements. The NiSource Inc. Board provides oversight to its subsidiary gas and electric distribution companies through review of collective gas and electric segments instead of by individual entity. Its main role is to assign available capital between the Gas Segment and the Electric Segment to then be further divided amongst the distribution companies as the executive teams of NGD and the Northern Indiana Public Service Company[2] (NIPSCO) determine appropriate. The NiSource Inc. Board conducts business through the following five, charted committees:

- Audit Committee – five independent and financially literate members, of which three qualify as SEC-defined financial experts, responsible for monitoring the integrity of the financial statements; the independence, qualifications, and performance of the external and internal auditors; compliance with legal and regulatory requirements; and, the risk assessment processes – typically meets 9X/year.

- Nominating and Governance Committee – six independent members responsible for identifying individuals qualified to become directors, recommending to the NiSource Inc. Board successful director nominee candidates for consideration during annual stockholders' meetings, developing corporate governance guidelines, evaluating stockholder proposals, and overseeing the annual performance evaluations of the NiSource Inc. Board and its committees – typically meets 5X/year.

- Environmental, Safety and Sustainability Committee – six independent members responsible for assisting in overseeing the programs, performance, and risks relative to environmental, safety, and sustainability matters – typically meets 5X/year.

[2] NiSource Inc.'s electric distribution entity

- Compensation Committee – five independent members responsible for discharging the NiSource Inc. Board's responsibilities relative to evaluation and compensation of NiSource Inc.'s executives; reviewing and recommending to the NiSource Inc. Board incentive compensation plans, policies, and programs intended to attract, retain, and appropriately reward employees to motivate performance toward the achievement of business objectives while aligning long-term interests with those of the NiSource Inc. stockholders; and reviewing the equal employment and diversity programs – typically meets 7X/year.

- Finance Committee – five independent members responsible for reviewing and evaluating the financial plans, capital structure, equity and debt levels, and dividend and financial policies –typically meets 6X/year.

The auditors reviewed the NiSource Inc. Board's and Board Committees' meeting agendas and minutes for the audit period and found that the NiSource Inc. Board and its committees engage in expected activities to fulfill its intended mission, meets regularly, and acts accordingly based on requirements, bylaws, and charters. The Corporate Secretary attends all NiSource Inc. Board and stockholders' meetings and records appropriate votes and minutes.

NGD and CPA are each privately held entities and therefore are not required to meet NYSE, Sarbanes-Oxley, nor SEC corporate governance requirements. Per NGD's and CPA's Bylaws, respectively, the number of directors that shall constitute each entity's board of directors shall not be less than one nor more than five persons. NGD's Board of Directors (NGD Board) is comprised of three NiSource Inc. and subsidiary officers. CPA's Board of Directors (CPA Board) is comprised of three NGD or CPA officers. Neither the NGD Board nor the CPA Board uses committees to conduct business nor does either maintain a routine, face-to-face meeting schedule. The NGD Board as well as the CPA Board engage in such activities as electing officers, declaring dividends, purchasing property, and approving financing activities which are typically performed by written vote.

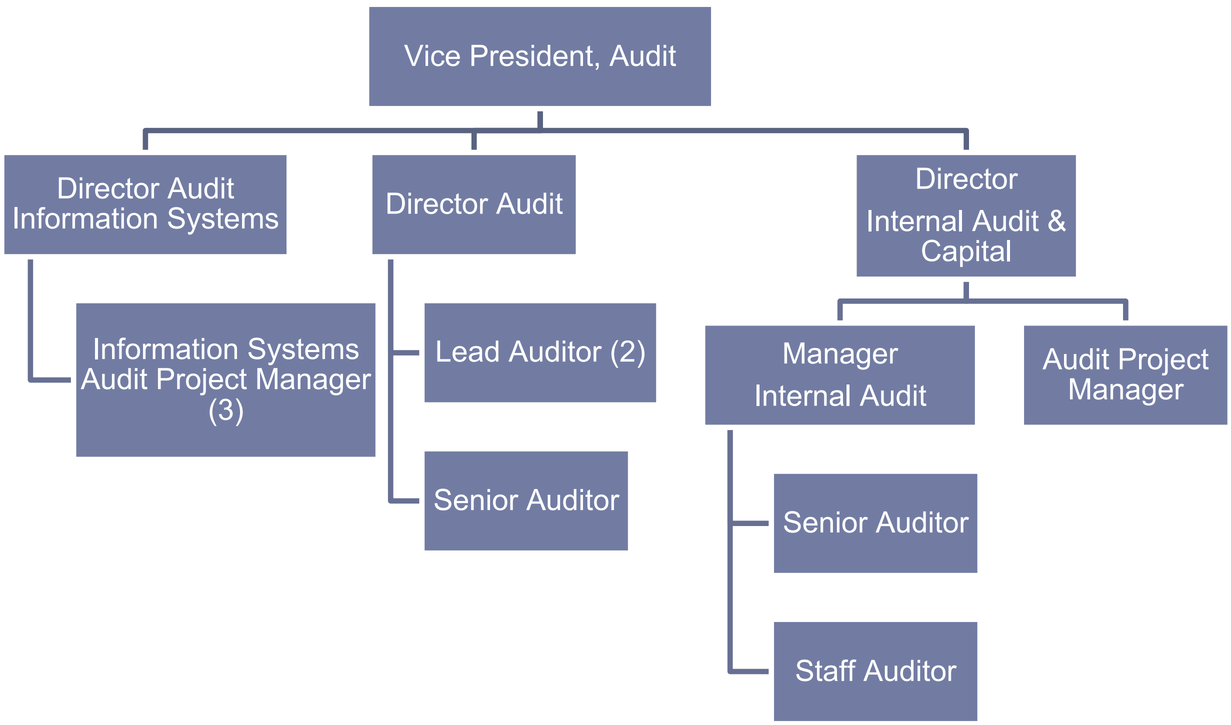
NiSource Inc. maintains a Code of Business Conduct that applies to all directors, officers, and employees of NiSource Inc. and its subsidiaries and affiliates to provide legal and ethical guidance which should be followed while conducting business. Employees can report a potential violation of laws, rules, regulations, or NiSource Inc. entities' policies by contacting a supervisor, human resources, the ethics department, or anonymously via the Ethics Hotline.

The following corporate governance guidelines and related documents are available on the NiSource Inc. website:

- NiSource Inc. bylaws
- NiSource Inc. board committees' charters
- Code of Business Conduct
- Corporate Governance Guidelines

The Internal Audit Department (IAD) performs the internal audit function for all NiSource Inc. entities, including CPA. The Vice President, Audit reports functionally to the NiSource Inc. Board's Audit Committee and administratively to the CEO. The NiSource Inc. Board's Audit Committee retains authority to appoint and replace the senior internal auditing executive. The organizational structure of the IAD is shown in Exhibit IV-1. As shown in the organization chart, the IAD is comprised of three Directors each with respective oversight responsibilities of Information Systems, NIPSCO, and Internal Audit and Capital related to all other NiSource Inc. entity operations.

Exhibit IV – 1
NiSource Inc.
Internal Audit Department Organization
As of December 2019



Source: Data Request CG-45

The IAD Charter describes the mission, scope of audit work, accountability, independence and objectivity, responsibility, authority, and standards of the IAD. All employees of the IAD participate in a group membership of the Institute of Internal Auditors. The Vice President, Audit formally presents the annual Internal Audit Plan to the NiSource Inc. Board's Audit Committee for approval. The IAD maintains an Internal Audit Manual which guides the employees through the preparation of the annual Internal Audit Plan, specific audit processes, communication of results, follow-up processes, and audit documentation.

Deloitte & Touche LLP (Deloitte) has served as NiSource Inc.'s external auditor since 2002. The lead partner and all lead engagement team members follow the standard rotation policy under Sarbanes-Oxley to ensure auditor independence.

NiSource Inc. searches for an external auditing firm on an as needed basis with the last search concluding in 2002. NiSource Inc. Board's Audit Committee performs an annual management survey and evaluation of Deloitte's services.

Findings and Conclusions

Our examination of the corporate governance functional area included a review of the various boards of directors including relative board committees' structure, activities, and charters; corporate governance policies and procedures; codes of business conduct and ethics; IAD functionality; and interactions with the external auditor. Based on our review, NiSource Inc. and its subsidiaries should devote additional efforts to improving the efficiency and/or effectiveness of its corporate governance functional area by addressing the following:

1. The corporate governance activities of Natural Gas Distribution Group, Inc. and Columbia Gas of Pennsylvania, Inc. are not adequately documented.

As mentioned above, the NGD Board and the CPA Board perform the legally required corporate governance activities but do so by written vote and do not conduct routine face-to-face meetings. The executive teams of both NGD and CPA conduct other corporate governance activities such as strategic planning, capital disbursement, budget approval, and performance review through non-chartered management committees which do not record formal meeting minutes.

Because the NiSource Inc. Board discusses the corporate governance of its subsidiaries at the Gas Segment and Electric Segment levels instead of by individual distribution company, its meeting minutes are too high-level to document the critical corporate governance activities of NGD and, furthermore, CPA. Maintaining adequate documentation of these activities at the subsidiary level is crucial for historical retention of decisions made and actions taken.

Recommendation

1. Formally record and retain minutes of all NGD and CPA management committee meetings during which corporate governance activities are performed. Alternatively, establish an Executive Committee for the NGD and CPA Boards of Directors, respectively, which would record and retain meeting minutes.

V. AFFILIATED INTERESTS AND COST ALLOCATIONS

Background

This chapter presents the results of the auditors' review of the transactions between Columbia Gas of Pennsylvania, Inc. (CPA or company) and its affiliates. As discussed in Chapter II – Background, CPA is a subsidiary of NiSource Gas Distribution Group, Inc. (NGD) which is owned by the energy holding company, NiSource Inc. CPA provides natural gas service to approximately 437,000 customers in 26 counties. CPA has various affiliates, but regular, material transactions occur between NiSource Inc., NiSource Corporate Services Company (NCSC), Columbia Gas of Ohio (COH), Columbia Gas of Maryland (CMD), Columbia Gas of Massachusetts (CMA), Columbia Gas of Virginia (CVA), and Columbia Gas of Kentucky (CKY).

NCSC's costs are billed to affiliates in accordance with FERC methods of allocation using PeopleSoft 9.1 Financial software. PeopleSoft 9.1 Financial is an Oracle integrated Enterprise Resource Planning system that contains the general ledger, accounts payable, and automated allocations applications used to support all direct billing and cost allocations. This system utilizes a 4-digit billing pool value used to calculate and bill charges to affiliates. Costs are directly charged to an affiliate whenever possible; however, some charges involve more than one affiliate and the billing pool details how expenses are then allocated among participating affiliates. NCSC currently updates the statistical data used in the approved allocation bases semi-annually or more frequently as needed.

CPA, as well as other NiSource Inc. affiliates, employ accounting procedures wherein department heads, or assigned delegates, are accountable for individual department costs and hold ultimate responsibility for the validity of any charge billed to a department by an affiliate. Intercompany charges are initiated, recorded, monitored, and paid by NCSC Corporate Services Accounting. These charges are then reviewed by NCSC's Corporate Services Accounting Manager (Accounting Manager). The Accounting Manager is responsible for overseeing the accounting system that identifies the costs for services that are subsequently billed to affiliates, including CPA; and is therefore, responsible for reviewing overall charges billed to each affiliate by NCSC. The management fee (largest portion of costs allocated to CPA from NCSC) is also a part of operating & maintenance (O&M) expense reviewed by the Gas Segment and Electric Segment controllers during the monthly financial submission process.

NCSC utilizes accrual-based accounting where accruals are made using projections at the time of entry with the potential that true-ups could occur reflecting actual service company billings. Intercompany billings are compiled of transactions that occur daily throughout the month/year. NCSC bills out for prior month activity on the third business day of the current month. Intercompany cash transactions to move funds between affiliates typically occur on the 15th day of the current month; however, the longest lag between billings and affiliate payments is expected to be no longer than 45 days.

Transactions are approved by designated positions within the accounting software at the point of entry. For example, manual journal entries created in the general ledger are approved by the Accounting Manager. Other entries, such as time and labor, are approved by respective supervisors as time sheets are reviewed. Employee expenses and accounts payable invoices are routed to a respective supervisor for approval prior to being posted to the general ledger. NCSC's billing process is mostly automated, and the transactions are posted directly to each affiliate's general ledger. Gas Segment Accounting is notified when NCSC management fee charges are posted to the general ledger and affiliate charges are reviewed as part of a month-end closing financial submission package.

CPA is allocated an expense budget from NCSC for services to be rendered in the future. Each NCSC business unit Budget Sponsor prepares a financial budget of anticipated expenses including the expected timeframe for when these expenses will be incurred. The Budget Sponsor also determines the appropriate allocation codes to be applied for the services to be provided. The NCSC allocations are updated annually based on 12 months of historical data and can be revised based on projected deviations. The Financial Planning and Analysis business unit is then responsible for compiling the NCSC business units' budgets and determining the total budgeted cost of service to be allocated to each affiliate, including CPA. The respective affiliates will then include the total budgeted cost of service allocation in its annual budget preparation.

Exhibits V – 1 and V – 2, on the next page, show the total charges to CPA from affiliates for the years 2017-2019. Charges from NiSource Inc. rose significantly due to the dissolution of NiSource Finance Corp. resulting in CPA's long-term borrowing now being held and passed through to CPA by NiSource Inc. CPA had increased charges from NiSource Inc.'s Money Pool (Money Pool) due to CPA's increased short-term borrowing activity as well as from higher Money Pool interest rates. Interest rates for all borrowings from and investments into the Money Pool are determined monthly as derived from the weighted average daily interest rate on short-term external borrowings and earnings on external investments by NiSource Inc. which were trending upward. CPA's charges from NCSC primarily increased due to payroll funding, on behalf of CPA, that is moved through the Money Pool; payroll liability transfers when employees move between affiliates; miscellaneous cash corrections; and, payroll taxes.

The charges to and from the other state gas distribution companies mainly consist of compensated labor costs by a state distribution company seeking assistance from an affiliate state gas distribution company on various projects which could include O&M work, capital construction projects, or, most often, emergency response activities. The costs fluctuate each year because they are dependent upon projects that arise which require a state gas distribution company to request assistance.

Exhibit V – 1
Columbia Gas of Pennsylvania, Inc.
Charges from Affiliates
For the Years 2017-2019

Business Unit	2017	2018	2019
Columbia Gas of Kentucky	$ 22,503	$ 20,639	$ 63,430
Columbia Gas of Ohio	572,904	749,345	606,767
Columbia Gas of Maryland	1,092,223	1,223,400	1,091,297
Columbia Gas of Virginia	258,620	212,018	200,630
Columbia Gas of Massachusetts	3,495	16,614	28,529
NCSC	186,513,397	175,284,175	197,220,589
NiSource Finance Corp.	29,564,850	---	---
NiSource Inc	2,958,396	34,695,503	37,460,115
Money Pool	774,886	1,361,554	1,561,033
Total - All Affiliates	**$221,761,274**	**$213,563,248**	**$238,232,390**

Source: Data Request AI-2 and Auditor Analysis

Exhibit V – 2
Columbia Gas of Pennsylvania, Inc.
Charges to Affiliates
For the Years 2017-2019

Business Unit	2017	2018	2019
Columbia Gas of Kentucky	$ 30,629	$ 53,018	$ 16,662
Columbia Gas of Ohio	188,077	463,191	596,686
Columbia Gas of Maryland	1,055,707	1,439,403	1,291,942
Columbia Gas of Virginia	311,725	436,018	432,491
Columbia Gas of Massachusetts	---	4,963,610	530,747
NCSC	---	---	14,816
Money Pool	367,700	---	125,005
Total - All Affiliates	**$ 1,953,838**	**$ 7,355,240**	**$ 3,008,349**

Source: Data Request AI-2 and Auditor Analysis

Following are the Commission approved affiliated interest agreements (AIA) on file that allow for the charges, shown above in Exhibits V – 1 and V – 2, among CPA and its affiliates:

- An AIA was filed by CPA on August 18, 2000 at Docket No. G-00000794 among CPA, CKY, CMD, COH, CVA, and Columbia Gas Transmission. The AIA was subsequently approved by the PUC on October 25, 2000 and it pertains to the provision of consulting, financial, regulatory, gas management, information technology, legal, and operations services among these affiliates.

- A securities certificate and AIA were filed by CPA on November 27, 2013 at Docket Nos. S-2013-2395719 and G-2013-2395728 to issue promissory notes to

NiSource Inc. in an amount not to exceed $150 million. Both the securities certificate and AIA were approved by the PUC on January 23, 2014.

- A securities certificate and AIA were filed by CPA on November 30, 2015 at Docket Nos. S-2015-2515414 and G-2015-2515982 to issue promissory notes to NiSource Inc. in an amount not to exceed $130 million. Both the securities certificate and AIA were approved by the PUC on January 28, 2016.

- An amended and restated AIA was filed by CPA on March 1, 2016 at Docket No. G-2016-2531552 among NiSource Inc. and its affiliates, including CPA, to update changes that had occurred since the PUC approved a previous inter-company income tax allocation AIA. On September 7, 2016, an amendment was filed by CPA in order to allow NiSource Inc. to comply with a new Indiana Utility Regulatory Commission policy that states that a contract will expire five years from its effective date. Northern Indiana Public Service Company (NIPSCO), an affiliate of CPA, was subject to the new policy. As such, the AIA has an end date of August 17, 2021. The AIA was subsequently approved by the PUC on September 22, 2016.

- A revised AIA was filed by CPA on August 15, 2017 at Docket No. G-2017-2619362 among NiSource Inc. and several of its affiliates, including CPA, to use a system money pool for short-term borrowing and lending. The revised AIA updated the previous AIA due to the dissolution of NiSource Capital Markets and NiSource Finance Corp. The AIA was subsequently approved by the PUC on October 25, 2017.

- A securities certificate and AIA were filed by CPA on November 6, 2017 at Docket Nos. S-2017-2632449 and G-2017-2632452 to issue promissory notes to NiSource Inc. in an amount not to exceed $160 million. Both the securities certificate and AIA were approved by the PUC on December 7, 2017.

- An AIA was filed by CPA on September 14, 2018 at Docket No. G-2018-3004657 between CPA and CMA to receive and provide operational support and training to and from each other. This AIA was approved by the PUC on September 14, 2018.

- An AIA was filed by NCSC on behalf of CPA on December 17, 2014 at Docket No. G-2014-2458547 to replace an existing Commission approved AIA. The AIA, subsequently approved by the PUC on April 1, 2019, details the provision of many types of services by NCSC for CPA for fees at the lower of cost or market.

NiSource Inc.'s Internal Audit Department performs an annual review of the accounting systems, source documents, allocation methods, and billing procedures used by NCSC to allocate costs/expenses to the respective affiliates. The scope of the audit includes procedures to determine that costs are equitably or otherwise appropriately allocated to all affiliates and to verify that controls are maintained to ensure that all costs are allocated monthly.

NiSource Inc. contends that CPA does not guarantee the borrowings of its affiliates, nor does it pledge its assets as collateral for the borrowings of its affiliates. These two practices insulate CPA's financial strength from that of its affiliates. Additionally, NiSource Inc. states that unregulated affiliates can invest into, but not borrow funds from, the Money Pool which is another form of insulation for CPA from the activities of unregulated affiliates.

Findings and Conclusions

Our examination of the affiliated interests and cost allocations functional area focused primarily on a review of contracts and agreements governing transactions between affiliates; cost allocation methodologies, policies, and practices; employee training on time and expense reporting; ringfencing efforts; internal audits of cost allocations; etc. Based on our review, NiSource Inc. and its subsidiaries should devote additional efforts to improving its affiliated interests and cost allocations functional area by addressing the following:

1. Columbia Gas of Pennsylvania, Inc. exceeded its borrowing limit under an approved securities certificate and did not comply with the reporting requirements of the Pennsylvania Public Utility Commission when it executed a loan.

Pursuant to 66 Pa.C.S. §§ 1901-1904, the PUC has authority to approve utilities' securities certificates detailing limits to the amount of money a utility can borrow in the form of long-term debt. Once a securities certificate is in place, the utility is to notify the PUC's Bureau of Technical Utility Services (TUS) within 60 days of any utility borrowing activities under the umbrella of the approved securities certificate.

At Docket Nos. S-2017-2632449 and G-2017-2632452, by way of Commission Order, CPA was approved for loan amounts from NiSource Inc. not to exceed $160 million. Subsequently, on June 29, 2018, a promissory note for $80 million was executed. Documentation of this loan was provided to the auditors on September 26, 2019. On November 25, 2019, CPA provided a schedule of inter-company loans with two additional loans listed without promissory notes. Upon request for the corresponding promissory notes, CPA disclosed the events surrounding an overborrowing situation of $20 million that had occurred. It was further explained that in September 2019, NiSource Inc. had issued another promissory note of $100 million. Shortly after the $100 million issuance, CPA had realized that the $100 million loan had exceeded its approved debt issuance under Docket No. S-2017-2632449. Counsel for CPA contacted TUS to inform them of the overborrowing and its intention to rescind the September 2019 promissory note. TUS concurred with CPA's rescission of the issuance; therefore, in November 2019, CPA rescinded the $100 million promissory note and re-issued for $80 million.

In discussions with TUS, it was also brought to the auditors' attention that CPA had not notified the PUC of the $80 million loan executed on June 29, 2018 within the 60-day notification requirement. The Commission was unaware of this activity until the overborrowing conversations had occurred between CPA and TUS in late 2019. As a result, CPA did not comply with the notification requirement when executing borrowing activities.

CPA has insufficient control in place to ensure borrowing activities comply with regulatory requirements. Insufficient control allowed for borrowing in excess of the Commission approved limit as well as allowed borrowing activities to commence without proper notification to the PUC per 66 Pa.C.S. § 1901.

2. The Cost Allocation Manual is outdated, and it does not use the NARUC Guidelines for Cost Allocations and Affiliate Transactions.

In March 1998, NARUC developed Guidelines for Cost Allocations and Affiliate Transactions (Guidelines). The Guidelines are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and affiliates in the development of procedures and recording of affiliate transactions. The Guidelines support the use of a cost allocation manual (CAM) which should be an indexed compilation and documentation of a company's cost allocation policies and related procedures. According to the Guidelines, each entity that provides both regulated and non-regulated services or products should maintain a CAM, or its equivalent, and notify the jurisdictional regulatory authorities of the CAM's existence. At a minimum, the CAM should contain the following:

1. organization chart of the holding company depicting all affiliates and regulated entities;
2. description of all assets, services, and products provided to and from the regulated entity and each of its affiliates;
3. description of all assets, services, and products provided by the regulated entity to non-affiliates; and,
4. description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

On July 31, 2019, the auditors requested review of the current CAM. CPA did not include a CAM with the original response it provided on September 25, 2019, but instead provided a document that detailed the methods of allocations used for each service department or function. During an interview to discuss the reasoning for not maintaining a CAM, it was disclosed that NCSC does have a CAM in effect. NCSC provided its CAM titled the Cost Allocation Manual Guide on January 21, 2020. Upon review of the CAM, it was noted that there was no documentation of review and/or revision. The CAM had a description of 20 total allocation methodologies used along with a department breakdown of which methodologies should be used for billing within each department. It was noted by the auditors that NCSC does not maintain a routine review schedule for its CAM and NCSC reported the last update was completed in August 2017 (not documented within the CAM).

The auditors believe that CPA should consider the NARUC Guidelines. NARUC has noted that the Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. It is intended to provide a framework for regulated entities and regulatory authorities in the development of policies and procedures for cost allocations and affiliated transactions. NCSC echoes that the Guidelines are not intended to be rules or regulations prescribing how cost allocations are to be handled and has not found value in consulting the Guidelines during the development of the CAM. NCSC has service agreements with affiliates that outline the services NCSC provides as well as uses FERC approved methods of allocation and believes this suffices. NCSC contends the CAM is evaluated on an as needed basis to determine if updates are necessary based on organizational changes. NCSC has not updated its CAM in recent years even though it has been going through significant reorganization.

Using an outdated CAM may result in employees incorrectly charging expenses to CPA or other affiliates. Errors in assigning charges can negatively affect ratepayers through inaccurate and/or inappropriate recovery. Like other company policies and procedures, the CAM should be regularly reviewed and updated to ensure appropriate guidance is available to staff responsible for completing work tasks.

3. NiSource Corporate Services Company has internal control deficiencies within certain accounting processes.

In discussions with CPA, it was disclosed that CMA charged CPA an amount of $23,745 without having first obtained approval of an AIA from the Commission. NCSC identified this omission during its year-end review and reversed approximately $13,000 of the charge due to the transaction having exceeded the $10,000 maximum amount allowed without an approved AIA on file with the Commission. According to NCSC, this occurred because the costs were incorrectly coded and then automatically charged from CMA to CPA as a part of the standard labor allocation process. Upon review, the labor charges were identified and reversed.

Internal control ensures operational effectiveness and efficiency; reliable financial reporting; and, compliance with laws, regulations, and policies. Deficiencies in internal control within accounting processes have resulted after reorganization of the NCSC accounting function[3]. Maintaining appropriate internal controls over certain accounting processes could have prevented the error described above. Failing to maintain appropriate internal control over certain accounting processes increases the risk of costly accounting errors which could result in penalties being assessed to an entity.

[3] NCSC accounting has recently moved to a centralized organizational design that has consolidated gas and electric transactional activities under a shared service center with remaining activities supported by gas and electric segment-aligned teams -- previously, there had been an NCSC controller position which has been eliminated

4. NiSource Inc. does not provide cost allocation training for employees.

Although NCSC has a CAM as an available resource, employees are not provided direct charge or cost allocation training to learn these general procedures and may not be aware that the CAM is available. Ultimate responsibility for selecting the appropriate method of direct charge or allocation lies with the employee or end user closest to the work being performed. It was further explained that when employees or end users have questions pertaining to allocation procedures, the accounting department would be available to provide guidance which places the burden on employees to know when they need guidance and to follow through by requesting guidance. Without introductory training however, employees may not be aware of the proper contacts or procedures.

Cost allocation training should be provided to NiSource Inc.'s employees, especially new hires, who are responsible for charging work task related expenses to respective NiSource Inc. affiliates. All resource materials referenced during training should be current and the work practices described therein should be in concert with actual work practices.

NCSC currently provides cost allocation spot training based on business needs or at the request of business partners and deems this method of cost allocation training sufficient. Therefore, NCSC does not believe there is a need for introductory cost allocation training or additional cost allocation refresher training. The auditors, however, believe that without introductory and additional refresher training, there is risk of inaccurate and/or inconsistent application of direct charge and/or cost allocation procedures. Because NCSC and its affiliates, including CPA, extensively use direct charge and cost allocation, there is a greater risk of employee error. Additionally, direct charge and cost allocation activity increased over the audit period. Errors in the assignment of direct charges or cost allocations could negatively impact CPA ratepayers, or the ratepayers of affiliates, through inaccurate and/or inappropriate recovery.

Recommendations

1. **Develop and implement controls to ensure that borrowing activities comply with regulatory approvals and notification requirements.**

2. **Develop and implement a review schedule to regularly update the NCSC CAM consulting the NARUC Guidelines for Cost Allocations and Affiliate Transactions.**

3. **Review and strengthen internal control subsequent to the NCSC accounting function reorganization.**

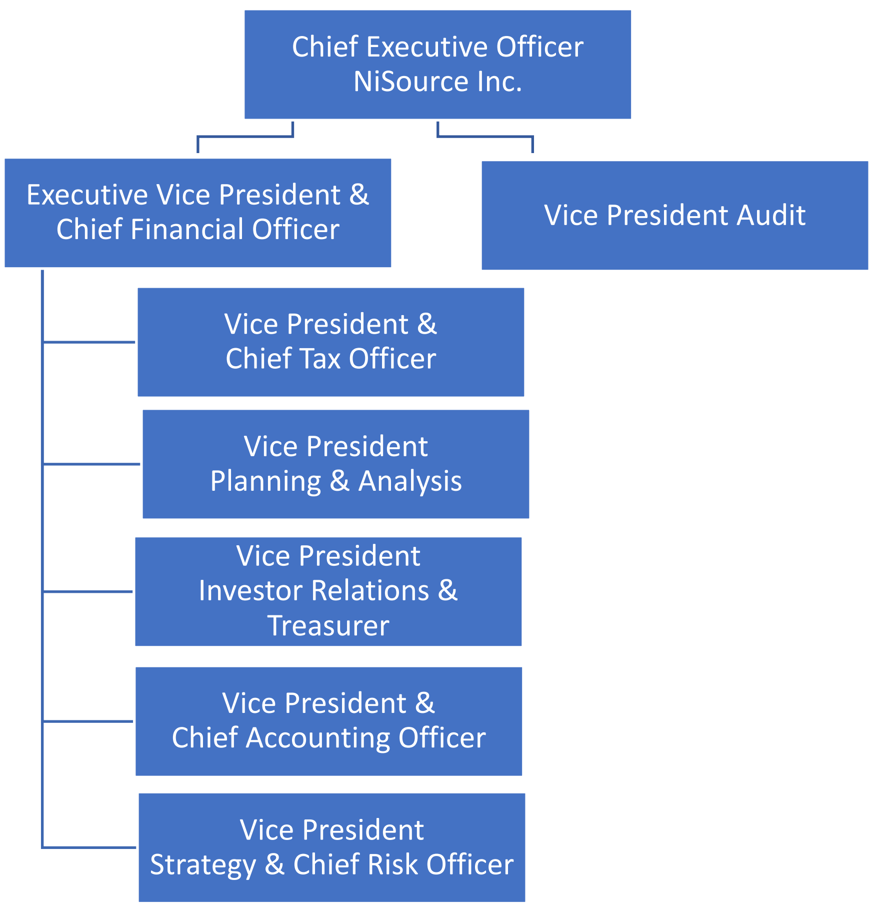
4. **Develop and implement cost allocation training for employees subsequent to the review and update of the CAM.**

VI. FINANCIAL MANAGEMENT

<u>Background</u>

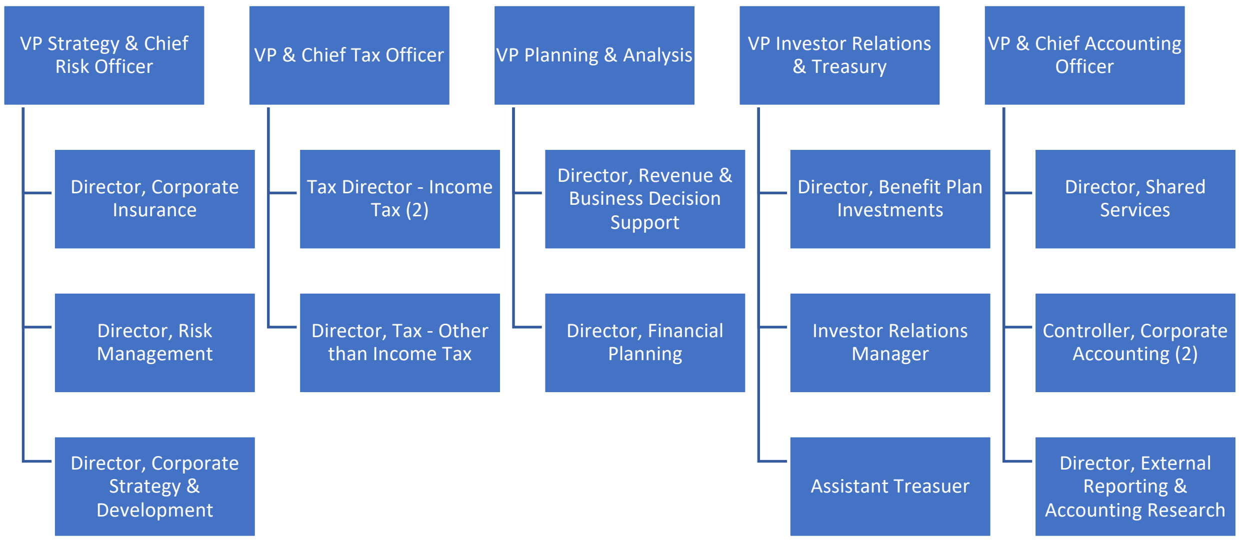
NiSource Corporate Services Company's (NCSC) Finance Department is overseen by an Executive Vice President and Chief Financial Officer (CFO). As shown in Exhibit VI – 1, the CFO leads several business units that include Tax, Planning and Analysis, Investor Relations and Treasury, Accounting, and Strategy and Risk Management. The Vice President, Audit directly reports administratively to the Chief Executive Officer of NiSource Inc. as well. Each business unit is shown in Exhibit VI – 2 and is described thereafter.

Exhibit VI – 1
NiSource Corporate Services Company
Executive Vice President & Chief Financial Officer and Vice President Audit
As of December 2019



Source: Data Request EM-3

Exhibit VI – 2
NiSource Corporate Services Company
Strategy & Risk Management, Tax, Planning & Analysis, Investor Relations & Treasury, and Accounting
December 2019



Source: Data Request EM-3

The Tax business unit (Tax) has the primary responsibility for compliance with all tax regulations, as well as planning, developing, and implementing strategies to optimize NiSource Inc.'s tax position. Tax must ensure that all tax reporting and accounting is accurate and in accordance with applicable local, state, and federal tax and accounting regulations. Tax's responsibilities also include, but are not limited to, acting as the primary interface for external auditors on all tax matters, ensuring adherence to internal procedures and controls, reviewing major and complex transactions in formative stages, and researching and implementation of compliance to new tax laws and reporting requirements.

The Financial Planning business unit's (FP) primary responsibility is to provide timely and accurate financial plans and scenario-based analysis that produces meaningful insights against prior year's financial plans. FP's responsibilities also include, but are not limited to, setting and communicating goals, providing management with upside and downside financial analysis and risk-based plan scenarios, analyzing root cause drivers of performance, and supporting scenario management with tracking progress against stated goals.

The Investor Relations business unit (IR) has the primary responsibility of the adherence and successful execution of NiSource Inc.'s investor relations program and managing corporate financing which includes maintaining key investment and banking community relationships. IR's responsibilities also include, but are not limited to, developing and presenting materials that help investors understand NiSource Inc.'s business strategy and financial results, monitoring capital markets' activity, participating in all aspects of the quarterly earnings process, and satisfying rate case informational requests.

The Corporate Accounting (CA) business unit has the primary responsibility of appropriately consolidating and reporting financial information in compliance with Security and Exchange Commission requirements. CA is also responsible for all regulated utilities, including Columbia Gas of Pennsylvania, Inc.'s (CPA or company), financial statements and the maintenance of both GAAP and FERC books. Encapsulated within CA are those responsible for asset accounting, accounts payable, and Sarbanes-Oxley Act duties which include maintaining accurate detail of all asset account activity, ensuring prompt and precise payment of vendor invoices, and verifying compliance with the internal control framework.

The Corporate Insurance business unit's primary mission is to manage and mitigate risk by employing best practice risk management principles, claims management, strategic procurement of insurance, and the willingness to adapt to the changing landscape of the insurance industry efficiently and effectively.

CPA's chain of command, which includes the State Finance Director (SFD), is shown in Exhibit VI – 3. The SFD is responsible for analysis and support of the financial planning, forecasting, and operating & maintenance (O&M) and capital budgeting processes for the company with CPA management and the NCSC finance department as primary internal stakeholders. While not directly responsible for compiling plans and variance reports, this position is the primary quality control and accountability point for the plan and vehicle by which variance analysis insights are communicated and translated into CPA's plan achievement. The SFD supports timely and accurate financial plans based on key strategic assumptions and presents variance analysis against the plans. The SFD also monitors actual performance for corporate functions that impact CPA and ensures that projected financial performance is accurately reflected in regulatory assumptions for revenue recovery.

Exhibit VI – 4 shows CPA's long and short-term debt for the years of 2014-2019. The $100 million loan, issued September 30, 2019, was rescinded and was re-issued for $80 million on November 22, 2019 (explained in more detail in Chapter V – Affiliated Interests and Cost Allocations). NiSource Inc. generates long-term borrowings by issuing unsecured notes through debt capital markets. CPA generates long-term debt by issuing inter-company promissory notes to NiSource Inc. CPA does not currently have long-term investments. CPA participates in NiSource Inc.'s centralized cash program, referred to as the NiSource Inc. Money Pool (Money Pool). When a participant has funds in excess of short-term cash needs, these funds are made available for use by other Money Pool participants and vice versa. CPA does not hold third-party investments or borrowings outside of the Money Pool. Exhibit VI – 5 shows where CPA has positioned itself through debt and equity financing at the end of the years 2014-2018, and as of September 30, 2019.

Exhibit VI – 3
Columbia Gas of Pennsylvania, Inc.
State Finance Director
As of December 2019

Source: Data Request EM-2

Exhibit VI – 4
Columbia Gas of Pennsylvania, Inc.
Long and Short-Term Debt
For the Years 2014-2019

		Amount	Interest Rate	Issuance Date	Maturity Date
CPA	Intercompany LT Debt	$ 30,000,000	4.43%	12/18/2014	12/16/2044
CPA	Intercompany LT Debt	$ 60,000,000	4.15%	3/24/2015	3/24/2045
CPA	Intercompany LT Debt	$ 60,000,000	4.51%	9/28/2015	9/28/2035
CPA	Intercompany LT Debt	$ 45,000,000	4.19%	3/31/2016	3/30/2046
CPA	Intercompany LT Debt	$ 85,000,000	4.44%	1/31/2017	1/31/2047
CPA	Intercompany LT Debt	$ 80,000,000	4.53%	6/29/2018	6/29/2048
CPA	Intercompany LT Debt	$ 100,000,000	3.57%	9/30/2019	11/21/2019
CPA	Intercompany LT Debt	$ 80,000,000	3.69%	11/22/2019	11/22/2049
Total	**Intercompany LT Debt**	**$ 540,000,000**	**4.19%**		
CPA	Intercompany ST Debt (Money Pool)	$ 89,796,655	2014	Ongoing	N/A
CPA	Intercompany ST Debt (Money Pool)	$ 28,258,102	2015	Ongoing	N/A
CPA	Intercompany ST Debt (Money Pool)	$ 110,693,700	2016	Ongoing	N/A
CPA	Intercompany ST Debt (Money Pool)	$ 147,016,107	2017	Ongoing	N/A
CPA	Intercompany ST Debt (Money Pool)	$ 73,830,119	2018	Ongoing	N/A
CPA	Intercompany ST Debt (Money Pool)	$ 142,397,626	2019	Ongoing	N/A

Source: Data Request AI-30

Exhibit VI – 5
Columbia Gas of Pennsylvania, Inc.
Capitalization Ratios
For the Years 2014-2019

	Debt	Equity
12/31/2014	46.38%	53.62%
12/31/2015	46.36%	53.64%
12/31/2016	46.04%	53.96%
12/31/2017	47.89%	52.11%
12/31/2018	46.21%	53.79%
09/30/2019	47.66%	52.34%

Source: Data Request FM-41

Exhibit VI – 6 below shows NiSource Inc.'s pension funding percentage as of December 31, 2018. This valuation was calculated through the most recent actuarial study performed by Aon. NiSource Inc. claims that its current pension plan funding policy is to contribute no less frequently than annually an amount equal to or greater than the minimum contribution required by law.

Exhibit VI – 6
NiSource Inc.
Qualified and Nonqualified Pension Plans Funding Status
As of December 31, 2018

Benefit Obligation	$ 1,981,278,487
Fair Value of Plan Assets	$ 1,867,699,564
Underfunded Amount	$ (113,578,923)
Funding Percentage	**94.3%**

Source: Data Request FM-33

NCSC's Internal Audit Department, which is discussed in more detail within Chapter IV – Corporate Governance, develops an annual Internal Audit Plan based on a corporate wide risk assessment. There is no set number of audits required to be conducted for CPA each year; however, CPA benefits from many internal audits covering multiple NiSource Inc. affiliates each year.

Findings and Conclusions

Our examination of the financial management functional area focused primarily on a review of accounting policies and procedures, the capital and O&M budget processes, budget variance tracking and reporting, long and short-term financing policies and activities, dividend policies, internal audit, and the pension program funding. Based on our review, NiSource Inc and its subsidiaries should devote additional efforts to improving its financial management functional area by addressing the following:

1. The Dividend Policy does not require the company to inform the Pennsylvania Public Utility Commission when the company plans to issue dividend payments in excess of 85% of net income.

On July 28, 2013, CPA's President signed into effect a formal Dividend Policy. The Dividend Policy details the process for determining whether dividends should be paid to NiSource Inc. and ultimately its shareholders. On a quarterly basis, NiSource Inc.'s CFO conducts an analysis that considers the following factors:

- total capitalization,
- net rate base,
- debt to equity ratio,
- regulatory precedent regarding capital structure,
- planned retirement/issuance of long-term debt,
- planned infusions of equity,
- liquidity,
- anticipated capital budget,
- cash from operations,
- planned/ongoing regulatory activity, and
- other factors as appropriate.

Upon completion of the analysis, the CFO would provide recommendations for consideration regarding a potential dividend payment. The CFO's recommendation with supporting documentation are then submitted to CPA's Board of Directors for consideration and approval. All such dividend payments are made in accordance with applicable Pennsylvania law; however, no explanation is routinely provided to the Pennsylvania Public Utility Commission (PUC or Commission) for dividend payments in excess of 85% of net income.

In general, it is not a sound business practice to pay a dividend to a parent company of more than 85% of the utility's net income on a consistent basis; however, there may be situations when higher than normal dividends are warranted for a particular period/year. Should such a situation occur, it would be a best business practice for the utility's dividend policy to include a provision for the utility to notify the Commission if it intends to pay dividend payments in excess of 85% of net income to explain the rationale for the dividend payment(s).

Per NiSource Inc.'s response, the PUC has not requested a written explanation of dividend payments in excess of a certain percentage of net income; therefore, the Dividend Policy does not include this requirement. Although CPA has not paid out dividends since 2013, including this provision in the Dividend Policy is a best business practice to ensure that CPA has adequately informed the Commission of a pending dividend payment that would be in excess of 85% of net income.

2. The NiSource Operating and Maintenance Governance Policy does not include a budget variance section to provide appropriate guidance to staff responsible for managing operating and maintenance budget variances.

Monthly O&M budget and capital budget variance reports are provided to CPA management from the NCSC financial planning and analysis department as well as through system reports. The SFD reviews the monthly and year-to-date results with the President of CPA, and field operations budget variances are reviewed during monthly staff meetings with CPA's Vice President/General Manager of Operations. A summary of material O&M and capital budget variances is discussed during the President of CPA's bi-weekly meetings with the executive management team and regulatory support personnel from Regulatory/Legal, Engineering, Construction, Operations, Large Customer Relations, and Marketing. The President of CPA provides current budget status as well as updates on projected budget variances throughout the remainder of the year. The meeting participants then propose plans for budget variance remediation as appropriate.

NiSource Inc.'s Capital Governance Policy has a project overruns section that details three levels of budget variances and how they should be managed moving forward; however, its Operating and Maintenance Governance Policy (O&M Policy) does not provide enough detail to provide guidance on how to manage O&M budget variances. Section 2.1 Item b. of the O&M Planning Process within the O&M Policy states, "Monthly variance reporting which measures financial performance relative to the Annual Financial Plan and prior year results"; however, there is not a section that provides appropriate guidance to staff relative to how O&M budget variances are to be managed.

Throughout the period of 2014-September 30, 2019, the O&M budget had several instances of large annual variances either in dollar amount or percentage (greater than ten percent). High dollar amount and percentage variances are shown below in Exhibits VI-7 and VI-8, respectively.

Exhibit VI – 7
Columbia Gas of Pennsylvania, Inc.
High Variances in Dollars
For the Years 2014-September 2019

	2014	2015	2016	2017	2018	September 2019
Corporate Service Fee	$2.8 million (6%)		$1.5 million (3%)	$1.5 million (2%)	$5.9 million (9%)	$1.5 million (4%)
Labor		17% ($682,000)		132% ($8.2 million)		$2.4 million (13%)
Outside Services		$1.2 million (5%)		$3.3 million (13%)	$1.7 million (7%)	$1.0 million (7%)
Benefits					$1.4 million (12 %)	
Other*	$1.0 million (6%)	$2.8 million (11%)	$2.6 million (10%)			$1.0 million (7%)
Trackers (Universal Service)			$2.5 million (11%)	$3.0 million (11%)		

* – Gas costs, rents and leases, corporate insurance, employee expenses, dues and donations, uncollectible accounts, vehicle and tool costs, other taxes, depreciation and amortization, and other miscellaneous expenses
Source: Data Request FM-15 and Auditor Analysis

Exhibit VI – 8
Columbia Gas of Pennsylvania, Inc.
Variances Greater Than 10% of Budget
For the Years 2014-September 2019

	2014	2015	2016	2017	2018	September 2019
Materials and Supplies				18% ($962,000)	19% ($1.3 million)	
Benefits		17% ($682,000)		132% ($8.2 million)		36% ($2.2 million)
Outside Services		5 % ($1.2 million)		13% ($3.3 million)	7% ($1.7 million)	7% ($1.0 million)
Benefits					12 % ($1.4 million)	
Other*					30% ($6.6 million)	
Trackers (Universal Service)	37% ($6.8 million)	47% ($8.5 million)				

* – Gas costs, rents and leases, corporate insurance, employee expenses, dues and donations, uncollectible accounts, vehicle and tool costs, other taxes, depreciation and amortization, and other miscellaneous expenses
Source: Data Request FM-15 and Auditor Analysis

The company provided the auditors variance reports with explanations for O&M expenses in 2019. Based on this review, it appears that NiSource Inc. uses a monthly threshold of $500,000 or 5%, or an annual threshold of $1 million or 10% during O&M variance analysis in practice; however, the company does not include these expectations within its O&M Policy.

An O&M budget variance section within the O&M Policy that requires documented explanations for variances that fall outside +/- 10%, at a minimum, of original budgeted amounts would provide appropriate guidance to staff responsible for managing O&M budgeting processes both in the current year as well as during planning processes for future years. Setting reasonable budget variance tolerance levels as well as requiring documented explanations for variances outside set tolerance levels allows for better management of the O&M budgeting and spending processes and promotes more accurate forecasting potentially reducing variances year after year.

3. NiSource Inc. does not maintain approval levels for internal transactions within its delegation of authority table.

CPA provided NiSource Inc.'s Accounting Policy: Requisition and Disbursement Approval Levels with the scope of this policy being limited to external procurement and disbursements; therefore, no approval levels for internal transactions are included. In addition, all inter-company transfers, except for intercompany financing, can be approved without limit by the Assistant Treasurer, Accounting Managers, Treasury Managers, Assistant Controllers, and Controllers. All intercompany financing is approved by the CFO.

Sizable internal transactions may be occurring that should be approved through appropriate levels of management within NiSource Inc. to ensure sufficient financial control, and additionally, there are examples of internal control deficiencies within certain monetary transactions (see Chapter V – Affiliated Interests and Cost Allocations Findings and Conclusions Nos. 1 and 3).

Maintaining appropriate approval levels over internal transactions within the delegation of authority table strengthens internal control over monetary transactions between affiliates. This is especially important in large organizations consisting of many entities. NiSource Inc. stated that because no funds are leaving the organization, including approval levels for internal transaction within the delegation of authority table is unnecessary. One benefit missed by NiSource Inc. is having layers of management approvals for inter-company transfers as an internal control to minimize errors. Even though funds are not leaving the organization, ratepayers can be affected by erroneous inter-company transactions.

4. Some of NiSource Inc.'s finance and accounting policies and procedures are incomplete and do not assign responsibility to who should ensure procedures are followed.

During fieldwork, the auditors noted that some of NiSource Inc.'s accounting and finance policies and procedures did not designate a responsible party nor scope. Listed below are demonstrations of this situation:

- Policies/procedures missing both scope and designated responsible party:
  - Treasury Operations Payment Guidelines

  - Cost Allocation Manual Guidelines
  - Cash Collections

- Policies/procedures missing designated responsible party:
  - The Accounting Policy: Requisition and Disbursements Approval Levels

The auditors noted that the Capital Planning Procedures, Operating & Maintenance Governance Policy, and Capital Governance Policy designated the responsible party and scope.

NiSource Inc. stated that for the Treasury Operations Payment Guidelines' responsibilities, it is implied that treasury operations owns the document, but it is not directly stated who is the owner.

NiSource Inc. contends that there is no direct responsibility listed for the Accounting Policy: Requisition and Disbursements Approval Levels (RDAL) as it is indirectly inferred that accounts payable owns the responsibility on the bottom of page 1 on question 7 "Any questions regarding this policy should be directed to Accounts Payable". The RDAL is owned by the Manager - Accounts Payable, and the approval thresholds contained in the RDAL were assigned to the Vice President and Chief Accounting Officer; however, neither are stated as such within the policy.

The Cost Allocation Manual Guidelines are available on the NiSource Inc. intranet and does not have a responsibility or scope section, but NiSource Inc. expects that users would reach out to NCSC accounting as questions arise. NiSource Inc. asserts that a scope can be explicitly outlined in future versions if considered a best business practice to do so.

As a best business practice, all policies and procedures should designate the scope and responsible party to provide appropriate guidance to staff performing work activities. Implications in policies allow for employee interpretation and misinterpretation. To ensure proper accountability, policies and procedures should designate a single employee as a responsible party. If multiple employees work under the governance of a policy/procedure, the department head should be the designated party. Policies and procedures that do not designate a responsible party and/or scope can lead to confusion, process gaps, and a lack of accountability.

Recommendations

1. **Revise the Dividend Policy to provide advance notice, including explanation of rationale, to the Commission whenever a dividend payment would exceed 85% of net income.**

2. **Include an O&M budget variance section that requires documented explanations when budget variances fall outside of defined variance tolerance levels in the O&M Policy.**

3. **Update the delegation of authority table to include approval levels for internal transactions.**

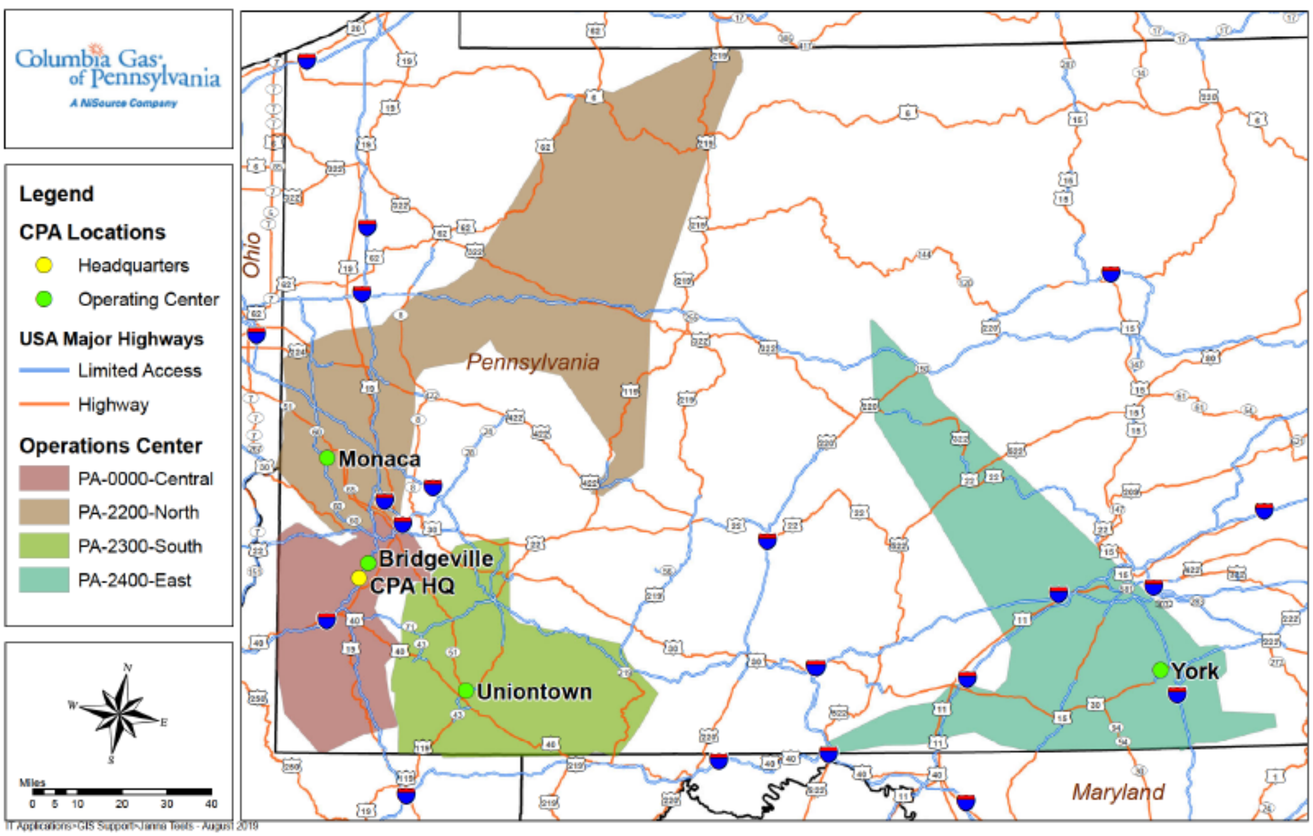
4. **Revise the Treasury Operations Payment Guidelines, the O&M Policy, the Delegation of Authority Table, and Cash Collections Policy to include a responsibility and scope section.**

VII. GAS OPERATIONS

Background

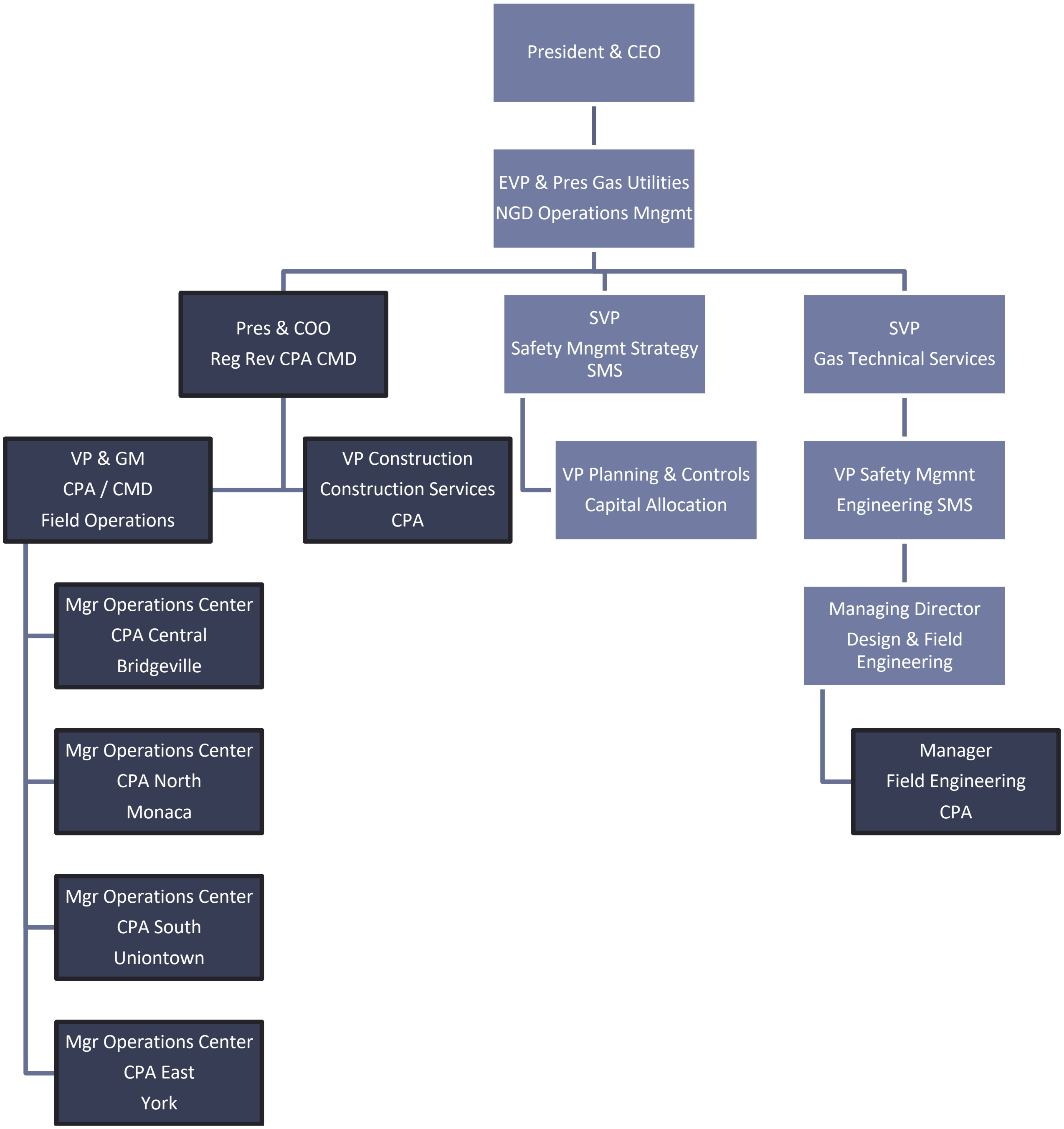
Gas operations functions managed by Columbia Gas of Pennsylvania, Inc. (CPA) include field operations, engineering, construction, metering and regulation, corrosion and leaks, emergency response, and damage prevention. NiSource Corporate Services Company (NCSC) provides assistance to CPA and NiSource Gas Distribution Group, Inc.'s other natural gas distribution companies by supporting operations related systems such as Supervisory Control and Data Acquisition (SCADA), Automated Roster Call Out System (ARCOS), and Work Management System (WMS). Exhibit VII – 1 displays the operating territory for CPA while Exhibit VII – 2 displays the organizational structure for gas operations functions at CPA.

Exhibit VII – 1
Columbia Gas of Pennsylvania, Inc.
Service Territory
As of December 2019



Source: Data Request GO-1

Exhibit VII – 2
Columbia Gas of Pennsylvania, Inc.
Gas Operations Function Organization[4]
As of December 2019



Source: Data Requests EM-2, EM-3, and Auditor Analysis

[4] Darker shaded boxes indicate CPA employees and lighter shaded boxes indicate NCSC employees

The positions which oversee the various responsibilities for CPA operations are as follows:

- VP & GM CPA / CMD Field Operations – operating and maintenance, metering and regulation, corrosion, inspections, leak surveys, damage prevention, emergency response
- Managers of Operations Centers – responsible for field operations at the four regional operations centers; note the East Operations Center being non-contiguous with the North, Central, and South regions
- VP Construction, Construction Services CPA – coordination for capital related construction projects
- VP Planning & Controls, Capital Allocation (NCSC Position) – capital budget planning, allocation, and monitoring
- Manager of Field Engineering (NCSC Position) – engineering, planning, repair/replace analysis

To assist with gas operations, CPA uses a WMS system which was custom designed by the company in the early 1990's and has been continuously enhanced since inception. The WMS contains work, asset management, and labor reporting for all maintenance and capital construction activities. The WMS interfaces with numerous systems and has various reporting capabilities. Some of the interrelated systems include financial and accounting systems, payroll and time reporting, customer information, service and main line leak information, abnormal operating conditions, distribution integrity management program (DIMP), geographic information systems, repair/replace prioritization software (*Optimain*), ARCOS, and SCADA.

To ensure uniform unaccounted-for gas (UFG) reporting, the Pennsylvania Public Utility Commission (PUC or Commission) adopted standard reporting requirements for UFG calculations in 2013 at 52 Pa. Code § 59.111. The standard reporting requirements distinguish and separate the UFG values for distribution, transmission, storage, and gathering losses. The auditors investigated UFG calculations based on the standard reporting requirements and found that CPA was appropriately calculating and including the necessary adjustments as identified in the PA Code. Additionally, CPA reported UFG levels are well within the distribution metrics specified in 52 Pa. Code § 59.111.

As part of the gas operations review, the auditors reviewed CPA's field operations staffing levels from 2014-2019. CPA staffing and overtime levels appear reasonable throughout this six-year period. There was a noticeable increase in staffing in 2019 for field operations due to the construction department decentralizing from NCSC back to local state operations in August 2019. Staffing and overtime (OT) for CPA's field operations is displayed in Exhibit VII – 3.

Exhibit VII – 3
Columbia Gas of Pennsylvania, Inc.
Gas Operations Field Staffing
As of December 2019

	2015		2016		2017		2018		2019	
Operations Center	**Staffing**	**OT**	**Staffing**	**OT**	**Staffing**	**OT**	**Staffing**	**OT**	**Staffing**	**OT**
CPA North	164	8.6%	170	7.0%	176	8.3%	176	11.7%	189	9.6%
CPA South	94	8.5%	99	7.0%	100	9.1%	102	13.2%	105	10.9%
CPA East	118	9.1%	122	9.1%	127	11.9%	137	14.8%	159	12.1%
CPA Central-Bridgeville	91	6.5%	93	6.8%	95	7.8%	94	10.9%	107	10.4%
CPA Central-Washington	64	7.8%	60	8.0%	61	8.9%	61	12.4%	63	11.7%
Total	**531**	**8.2%**	**544**	**7.6%**	**559**	**9.2%**	**570**	**12.7%**	**623**	**10.8%**

Source: Data Requests GO-4 and GO-34

Field operations staff is unionized, and each operating region is represented by one of five local branches of two different unions as listed below:

- **PA North** – Utility Workers Union of America AFL-CIO, Local Union No. #475
- **PA Central** – Bridgeville – Utility Workers Union of America AFL-CIO, Local Union #479
- **PA Central** – Washington – United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial, and Service Workers International Union AFL-CIO-CLC, Local Union No. 7139-03
- **PA South** – United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial, and Service Workers International Union AFL-CIO-CLC, Local Union No. 13836-14
- **PA East** – United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial, and Service Workers International Union AFL-CIO-CLC, Local Union No. 1852-17

Based on the 2018 Department of Transportation annual report (which contains data as of mid-year 2018), CPA had approximately 1,200 miles of unprotected bare steel and 80 miles of cast/wrought iron in its system. According to CPA, all priority pipe (bare steel and cast iron) is planned to be replaced by the end of 2029. The auditors reviewed CPA's capabilities to meet this 2029 targeted date including a review of the previously mentioned DIMP plan and *Optimain* software which utilizes established company algorithms and prioritization of pipeline replacement. The auditors found CPA's methodology and processes to be effective. The auditors also reviewed historical and planned replacement rates for priority pipe for CPA; specifically, the replacement rates specified in the approved Long-Term Infrastructure Improvement Plan (LTIIP), on file with the Commission, against actual company performance. In

2018, CPA replaced 27.4 miles less than planned due to changes in the company's policies and procedures regarding work on low pressure systems. To address this shortage, CPA replaced an additional 25.1 miles in 2019 and plans on replacing an additional 2.3 miles in 2020 from the previous planned replacement schedule in the current LTIIP. Exhibit VII – 4 displays this information along with planned replacement rates for 2020-2022.

Exhibit VII – 4
Columbia Gas of Pennsylvania, Inc.
Pipeline Replacement Rates
For the Years 2018-2022

Year	Approved LTIIP Pipe Replacements (Mi)	Actual Pipe Replacements (Mi)	*Anticipated Planned Pipe Replacements (Mi)*	Actual or *Anticipated* Variance (Mi)
2018	130.7	103.3		-27.4
2019	130.7	155.8		25.1
2020	138.3		*140.6*	*2.3*
2021	141.1		*141.1*	*0.0*
2022	142.0		*142.0*	*0.0*

Source: Data Request GO-39

Findings and Conclusions

Our examination of the gas operations functional area included a review of assigned responsibilities, policies and procedures, capital and operating and maintenance budgets and expenditures, system operations, preventative maintenance, capital planning, workforce management, emergency response, gas control, unaccounted-for-gas, safety, and related operations-based software systems, etc. Based on our review, no evidence came to our attention that would lead the auditors to conclude that areas reviewed were not being adequately addressed.

Recommendations

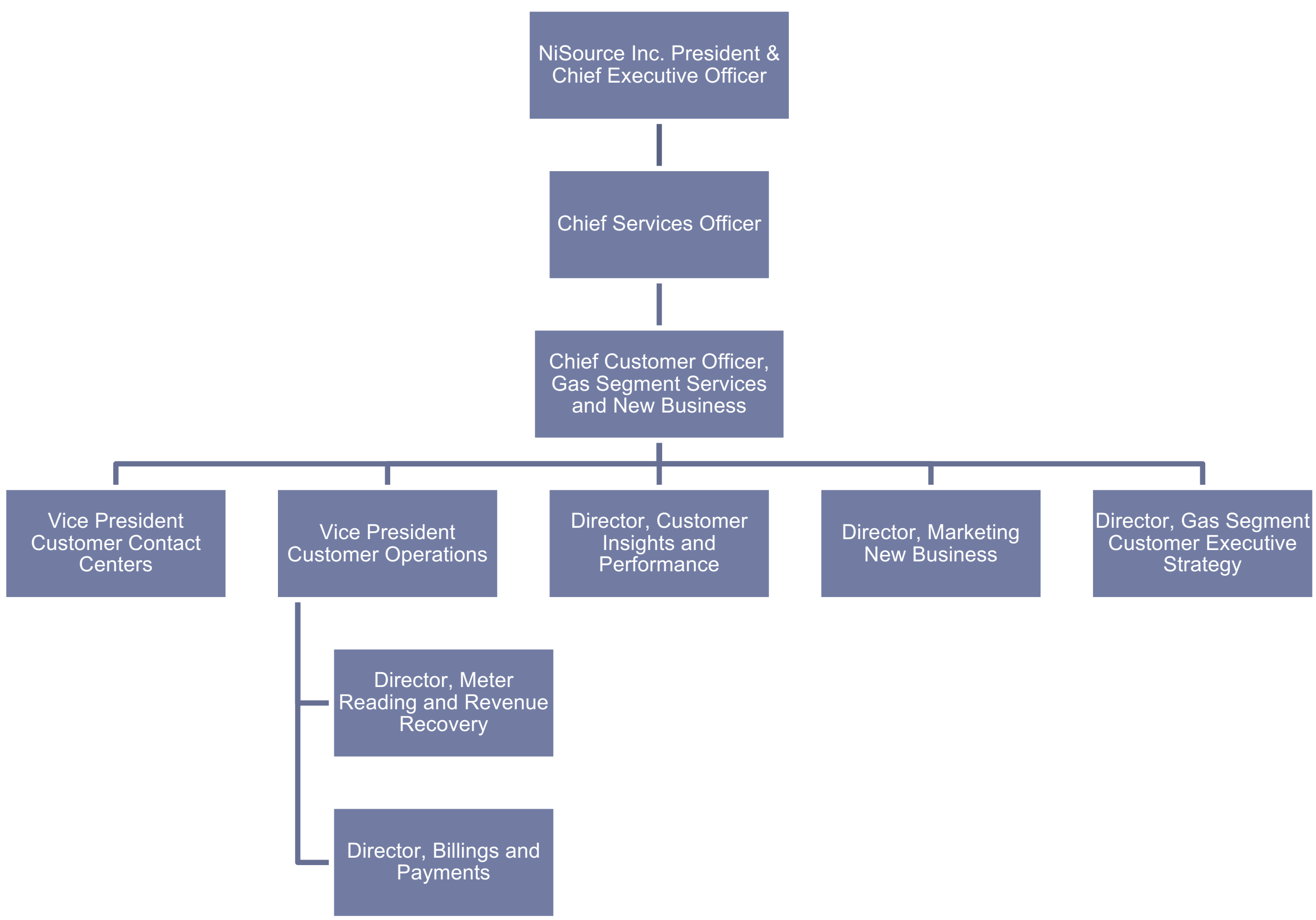
None

VIII. CUSTOMER SERVICE

Background

The primary focus of this chapter is the customer contact center operations and meter to cash functions which generally include metering, billing, and revenue recovery. NiSource Inc. maintains these and other customer experience focused business units under the leadership of the Chief Services Officer who reports directly to the President & Chief Executive Officer. As shown in Exhibit VIII – 1, NiSource Corporate Services Company's (NCSC) Gas Segment Customer Service & New Business is the business unit which oversees the customer contact center operations and meter to cash functions and is led by the Chief Customer Officer who reports to the Chief Services Officer. In addition to call center operations and the meter to cash functions, this business unit also oversees Customer Insights & Performance, New Business Marketing, and Gas Segment Customer Executive Strategy.

Exhibit VIII – 1
NiSource Corporate Services Company
Customer Service Organization
As of December 2019



Source: Data Requests EM-3 and CS-82

NCSC maintains three customer contact centers each dedicated to service the customers of specifically designated NiSource Inc. regulated utilities. The Smithfield Customer Contact Center (CCC) located in Smithfield, PA services Columbia Gas of Pennsylvania, Inc.'s (CPA or company) customers as well as the customers of the Ohio, Virginia, Kentucky, and Maryland state gas distribution subsidiaries.

The CCC organizational structure is shown in Exhibit VIII – 2. The Director, Customer Contact Center reports to the Vice President, Customer Contact Center who reports to the Chief Customer Officer as described earlier in the chapter. The Director, Customer Contact Center has ultimate responsibility for maintaining excellent service standards through the function's ability to respond to customer inquiries. Customer inquiries are made via telephone, email, or online form and typically, fall into one of three categories:

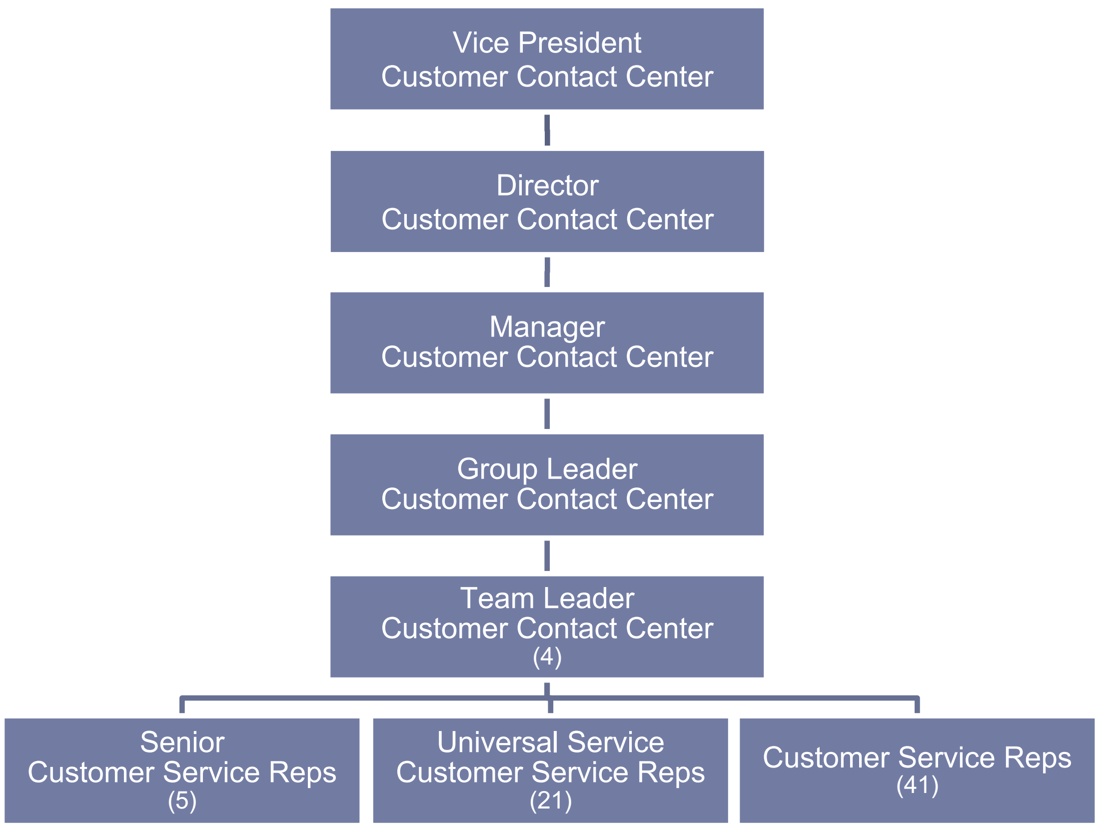
- Customer Service – inquiries relative to billing issues; credit and collection issues; or requests to connect, disconnect, or transfer utility service
- Emergency – reports of gas odor, fire, explosion, high pressure, or other situations in need of immediate response
- Web Self-Service Help – inquiries relative to technical issues experienced while using the web self-service applications

The Vice President, Customer Contact Center oversees the CCC as well as the Merrillville Customer Contact Center in Merrillville, IN. He works within the Gas Segment Executive Team to establish service targets, performance goals, and strategic plans. NCSC initiated various levels of organizational restructuring beginning in 2016. Prior to 2016, there was a single Director, Customer Contact Center overseeing all three customer contact centers. Currently, there are two director positions. The Director, Customer Contact Center shown in Exhibit VIII – 2 oversees the CCC solely, which is non-unionized, and the second Director, Customer Contact Center oversees the other two unionized facilities.

Along with organizational restructuring efforts, NCSC determined that the CCC, previously outsourced, would be better managed internally to provide customer service to desired standards. The CCC was officially insourced in November 2016. Because root cause analysis had highlighted employee job dissatisfaction as the underlying cause of poor performance when the CCC was outsourced, the primary goal of insourcing was to improve customer service performance, and ultimately customer satisfaction, by improving corporate culture and working conditions through the implementation of an employee-focused environment and organizational structure.

Upper level management developed additional layers of leadership for the CCC in order to create a stronger career path for CCC staff. A newly created Manager, Customer Contact Center maintains managerial responsibility over the collective operations of the CCC. Customer Service Representatives (CSRs) are trained to serve general customer inquiries of a specific state gas distribution subsidiary or by specific function such as emergency response, website technical assistance, universal services assistance, or back office administrative functions (e.g., responding to email/website form inquiries, security deposit documentation, processing refund requests). CSRs assigned to serve CPA customers report to one of four CPA Team Leaders. The four CPA Team Leaders report to the CPA Group Leader. Team Leaders motivate CSRs through positive reinforcement activities to achieve customer service excellence and conduct coaching sessions with CSRs when improvement opportunities are identified. The Group Leader supports the efforts of the Team Leaders as well as collaborates with CCC management on performance initiatives. CSRs also have an opportunity to be promoted to Senior CSR who provides front-line, on-the-job mentoring assistance to less experienced CSRs prior to escalating questions to Team Leaders.

Exhibit VIII – 2
NiSource Corporate Services Company
Pennsylvania Customer Contact Center Staff Organization[5]
As of December 2019



Source: Data Requests EM-3 and CS-82

After insourcing, the CCC facility was fully renovated in 2017. A newly organized open format with ergonomic, sit/stand workstations was designed for staff and supervisor efficiency, productivity, safety, and security. Other enhancements provided through renovation included fully equipped training rooms and practice areas, coaching

[5] The CCC provides service to the customers of five of NiSource Inc.'s subsidiary regulated utilities, but is structured to assign dedicated staff to provide service solely to CPA customers – in Exhibit VIII – 2, the Group Leader and below are CPA-dedicated staff and the Manager, Customer Contact Center and above oversee general CCC operations

and team meeting areas, a self-serve cafeteria, and natural gas-powered back-up power generation. Improvements in both employee satisfaction and customer satisfaction were achieved throughout the restructuring and modernization efforts.

In addition to the inquiry response functions, there are three customer contact center support business units as well: Training and Quality Assurance (QA), Workforce Planning and Data Integrity, and Cross Functional Business Process. NCSC is unique in that it maintains much of its customer contact center support functions in-house and develops many of its own programs, tools, and resources. There is well-developed communication and collaboration between the different support functions to ensure seamless application of the various systems and applications used by CCC management and staff.

Training and QA is responsible for providing new hire and continuous development training curriculum as well as for monitoring CSR performance to identify performance gaps, standardize communication processes with customers, and ultimately, improve the customer experience. QA Specialists review and evaluate CSR performance using a monitoring software. The software records the audio of each call as well as displays the CSR's screen activity during each call. This advanced technology allows the reviewer to not only hear the CSR's interaction with each customer, but also to evaluate if the CSR is efficiently and effectively using the resources available to assist customers. Calls can be monitored both in real time and from pre-recorded data allowing for ideal flexibility within the CSR monitoring activities. For pre-recorded data, QA Specialists can pause or rewind and replay a segment of a call to allow for thorough evaluation. This system negates the need for awkward side by side observations used by many utilities which does not represent true CSR performance since the CSR is aware of the ongoing observation and may result in limited evaluation of various call types since the evaluations are limited to the types of calls that are received during planned observations.

QA Specialists review and evaluate five calls per month for each CSR. The calls are strategically selected based on length of call type such as credit, billing, order takes, emergency, and miscellaneous. QA Specialists evaluate the effectiveness of CSR calls by completing a detailed observation checklist which identifies soft and technical skills and contains criteria to measure customer satisfaction and first contact resolution. There are performance targets with corresponding rewards or developmental exercises relative to the results of performance evaluations. If the CSR does not attain a score above 91%, a coaching session is required between the QA Specialist and the CSR. During this coaching session, the CSR will listen to the call and identify areas for improvement before any advice is given by the QA Specialist giving the CSR a chance to self-identify opportunities for improvement. Training and QA also uses trended performance data to identify opportunities to develop and implement refresher training or to improve current curriculum in areas showing consistently low scores. Trended performance data may also be shared with other business units to improve areas of customer service which may be highlighted by increased customer complaints pertinent to a certain service or process.

Workforce Planning and Data Integrity is responsible for reviewing historical trends, evaluating internal and external productivity factors, and benchmarking with industry standards of like utilities to maximize efficiency within the CCC. It reviews performance and call statistics to determine optimal CCC staffing levels. The call statistics monitored are wait time, escalated calls, and total calls handled.

Cross Functional Business Process is responsible for the development, maintenance, and continuous improvement of applications and resources used throughout the CCC. *Call Aid*, introduced in 2002, is a digital, readily accessible knowledge management system which houses current customer service data to assist CSRs working to satisfy customer inquiries. Another such resource is the *NiSource Robotic Automation Technology* (*NiBOT*) which is an auto-loaded CSR assistance application built in-house in 2011. *NiBOT* prompts CSRs during customer interactions based on input criteria and directs CSR responses and actions to apply consistent desired procedures for many service processes.

The CCC operational costs are directly charged to specific state gas distribution companies as appropriate and are otherwise allocated across the five state gas distribution companies serviced by the facility. Utility call center performance is monitored by the Pennsylvania Public Utility Commission's Bureau of Consumer Services (BCS). BCS collects and publishes reports on telephone access performance using the following three percentage metrics:

- Busy-Out Rate – number of calls that receive a busy signal divided by the total number of calls received

- Call Abandonment Rate – number of calls that were abandoned (customer disconnects call during a period on hold) divided by the total number of calls received

- Calls Answered Within 30 Seconds – percentage of calls answered within 30 seconds by an interactive voice response (IVR) system or a CSR ready to render assistance

CCC performance for these three metrics for the years 2014-2018 is shown in Exhibit VIII – 3. The CCC has maintained an average Busy-Out Rate rounded to 0% and an average Call Abandonment Rate rounded to 2% throughout the period. CPA has shown fluctuation in Calls Answered Within 30 Seconds but has considerably improved its performance in 2018.

Exhibit VIII – 3
NiSource Corporate Services Company
Pennsylvania Customer Contact Center Performance
For the Years 2014-2018

Year	Busy-Out Rate	Call Abandonment Rate	Calls Answered Within 30 Seconds
2014	0%	2%	77%
2015	0%	2%	84%
2016	0%	2%	78%
2017	0%	2%	82%
2018	0%	2%	87%

Source: 2014-2018 BCS Customer Service Performance Reports

The following initiatives were implemented or expanded to enhance performance at the CCC throughout the audit period of 2014-2019:

- At-Home Agent Program – offers an alternative work environment to CSRs which offers flexibility to both staff and management to limit overtime and reduce turnover rates; implemented 2013 and currently being expanded

- *Hallmark Business Connections* – third-party service allowing CSRs to send greeting cards to customers who indicated an issue that warrants a compassionate response (e.g., new home, birthday, loss of loved one); implemented June 2018

- Internal Recruiters – two internal recruiters were hired to focus on the recruiting challenges of the NiSource Inc. customer contact centers; on-site at the CCC as of September 2018

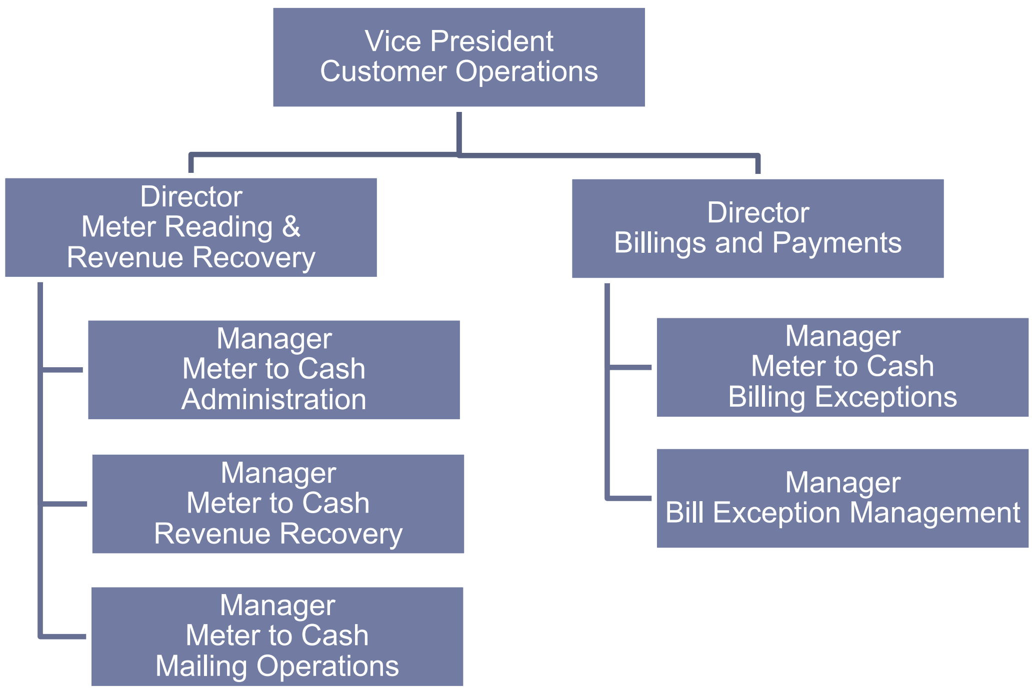
- Website Redesign – first major website redesign since 2004 to improve customer satisfaction through ease of navigation and full-site functionality even on mobile devices; launched February 2019 with added scalability to allow for continuous improvement

- Third-Party Retention Application – third-party application intended to improve retention rates by gathering staff satisfaction feedback, primarily pertaining to interactions between staff and supervisory/management teams, from surveys and then to strategically implement supervisor/management training programs where deficiencies are identified; implemented June 2019

- Conversational IVR – automated caller response system which provides a spoken interface that directs incoming calls efficiently as well as increases the customers' ability to self-serve; updated October 2019

Exhibit VIII – 4 shows the meter to cash function organizational structure overseen by the Vice President of Customer Operations who reports to the Chief Services Officer as described earlier in the chapter. The meter to cash business units consist of Meter Reading, Billing, Printing and Inserting, and Revenue Recovery. In addition to the core meter to cash function, the Vice President, Customer Operations also oversees the Gas Transportation Program and the Project Customer Operations.

Exhibit VIII – 4
NiSource Corporate Services Company
Meter to Cash Function Organization
As of December 2019



Source: Data Requests EM-3 and CS-82

The Meter Reading staff consists of one CPA employee and eight contractors whose primary responsibility is to read customer meters using automated meter reading (AMR) technology. Mass installation of AMR devices for residential and small commercial customers was completed in December 2012. CPA continues to make progress toward achieving compliance with 52 Pa. § 59.18 requiring meter sets to be located outside and above ground by September 2034. As of September 2019, CPA had approximately 58,672 meters still located inside a structure. Between 2014 and 2018, CPA relocated approximately 4,000 meters per year which is an acceptable pace to comply by the effective date.

Billing is responsible to ensure timely and accurate customer billings. CPA's billing processes are fully automated starting with an AMR meter reading entered into the customer care system which triggers a billing statement to be created. There are controls built into the system to detect if abnormal usage or billed amounts are used in the creation of a customer billing which creates an exception that must be reviewed by billing staff. Upon review, Billing staff determines a solution to ensure an accurate billing statement is prepared. If an exception requires extensive investigation, billings can be prepared using estimated usage to ensure each customer is billed within each billing cycle.

Customer payments are due 23 days from the date the billing is prepared. Currently, 35% of customers pay with a check or money order by mail, 22% pay using an electronic check payment initiated through a financial institution or other third-party site, 19% pay through prescheduled autopay services, 13% pay using a one-time electronic payment initiated through the NiSource Inc. website, 9% pay by phone having called into the CCC, and 2% pay at an authorized third-party walk-in payment location. Payments collected via electronic systems, by mail, and by third-party bill payment service providers are processed to CPA accounts the same day.

Printing and Inserting is responsible for printing and mailing customer billings and other notices. In 2017, new equipment was purchased for use by the in-house operation and the prior equipment was retained as redundant availability in case of emergency. As of December 2019, approximately 81% of customers receive mailed billings and 19% of customers use paperless billing options.

Revenue Recovery is responsible for collection processes on accounts in arrears[6]. CPA maintains contracts with multiple third-party collection services. Collection performance is monitored by the Revenue Recovery team. All unpaid final billed accounts, not shut off for non-payment, are sent to a third-party vendor for early-out collections activities including outbound calls and reminder letters which are attempted for the first 28 days of account delinquency. Following the early-out activities, remaining delinquent accounts are sent to one of several primary placement collection agencies for an additional nine months. After the nine-month collection period, remaining delinquent accounts are placed with a secondary placement agency. The secondary agency will actively attempt collection for 12 months. Accounts with unpaid balances that have been through the active collection phases are then placed in warehouse collection service which monitors delinquent customer credit reporting for updates which reactivates a period of active collection using updated contact information as reported through the credit reporting agency.

CPA offers assistance to its low-income customers through programs detailed in its Commission-approved Universal Service and Energy Conservation Plan. The programs include:

- Customer Assistance Program (CAP) – assists long-term payment troubled customers by offering affordable payment options

- Low-Income Usage Reduction Program (LIURP) – offers opportunities for weatherization and other usage reduction measures at no cost

[6] CPA defines an account in arrears as being more than 30 days unpaid past the payment due date

- Low-Income Home Energy Assistance Program (LIHEAP) – helps eligible households maintain utility service during winter months
- Hardship Fund – provides financial assistance for customers to help pay outstanding balances
- Customer Assistance Referral and Evaluation Services (CARES) – assists in basic budget counseling, customized payment plans, and referrals to energy grant programs and community resources

Findings and Conclusions

Our examination of the customer service functional area included a review of the organizational structure, current policies and procedures within metering; billing; and collections activities, performance measures and levels, customer information systems, customer contact center operations, and universal services. Based on our review, NCSC should initiate or devote additional efforts to improving the efficiency and/or effectiveness of its customer service functional area by addressing the following issues:

1. The metering and billing policies and procedures are outdated.

After the auditors' review of the metering and billing procedures, it was determined that the metering and billing policies and procedures have not been periodically reviewed for possible need of update. Some metering policies/procedures were made effective in 1981 with no indication of review/update and some billing policies/procedures were made effective in 1976 with no indication of review/update.

NCSC does not maintain an active review schedule of its metering and billing procedures. Outdated resource documents do not provide appropriate guidance to staff responsible for work activities and could result in inaccurate, inconsistent, and inefficient metering and billing practices. Routinely following a review schedule for the metering and billing policies and procedures would ensure timely updating to further ensure appropriate work practices are effectively communicated to staff.

2. Average arrearages were higher throughout the audit period compared to a panel average of Pennsylvania natural gas distribution companies.

CPA's overall average arrearages were compared to a panel of Pennsylvania natural gas distribution companies (NGDCs) for the years 2014-2018, which appear in the Universal Service Programs and Collections Performance Reports (USP & Collections Reports) published by BCS. As shown in Exhibit VIII – 5, CPA's overall average arrearages were substantially higher than the panel average over the period.

Exhibit VIII – 5
Columbia Gas of Pennsylvania, Inc.
Panel Comparison – Overall Average Arrearages
For the Years 2014-2018

	2014	2015	2016	2017	2018
Peoples	$380.25	$359.44	$198.86	$270.75	$351.36
PECO-Gas	$498.41	$463.98	$402.06	$389.10	$383.03
NFG	$380.87	$386.64	$262.51	$209.11	$190.66
Peoples-Equitable	$411.81	$371.34	$189.72	$240.14	$313.15
UGI-Gas	$308.43	$291.46	$215.72	$226.08	$293.79
UGI Penn Natural	$404.55	$406.48	$292.11	$280.91	$372.42
Panel Average	$397.39	$379.89	$260.16	$269.35	$317.40
Columbia Gas of PA	$487.04	$540.98	$440.53	$455.54	$507.04

Source: 2014-2018 USP & Collections Reports and auditor analysis

Likewise, CPA's overall average arrearages for confirmed low-income customers were compared to the same panel of Pennsylvania NGDCs for the years 2014-2018. In Exhibit VIII – 6 below, CPA's overall average arrearages for confirmed low-income customers were higher than the panel average over the period except for 2014.

Exhibit VIII – 6
Columbia Gas of Pennsylvania, Inc.
Panel Comparison – Overall Average Arrearages for Confirmed Low-Income Customers
For the Years 2014-2018

	2014	2015	2016	2017	2018
Peoples	$557.11	$460.32	$257.69	$391.38	$482.56
PECO-Gas	$1019.20	$976.70	$828.50	$778.23	$792.98
NFG	$480.81	$499.14	$390.47	$285.66	$269.36
Peoples-Equitable	$541.85	$477.20	$253.05	$342.47	$387.79
UGI-Gas	$408.35	$411.07	$328.40	$394.20	$588.52
UGI Penn Natural	$494.61	$515.15	$390.26	$421.59	$646.81
Panel Average	$583.66	$556.60	$408.06	$435.59	$528.00
CPA	$569.45	$619.67	$529.75	$549.70	$602.49

Source: 2014-2018 USP & Collections Reports and auditor analysis,

As previously mentioned in Finding and Conclusion No. 2 of Chapter III – Executive Management and Organizational Structure, the Revenue Recovery business unit was unaware of the available panel comparison published by BCS in the USP & Collections Report which may have resulted in its being unaware of its less than average arrearage level performance. In addition, budget billing arrangements as well as credit adjustments to CAP customer accounts have affected the integrity of arrearage data being reviewed.

When customers enroll in budget billing, a levelized monthly payment is calculated by dividing the historical annual usage over the current twelve-month period. During low usage months, the levelized payment is more than what would be billed the customer under the standard payment arrangement resulting in a credit being accumulated to the customers' accounts to be applied during higher usage months when the levelized payment amount is less than what would be billed on the standard payment arrangement. Credits being applied to customer accounts of those enrolled in CAP can also result in a credit balance during low usage months which will be accumulated for use during higher usage months.

Revenue Recovery relies on Information Technology (IT) to capture arrearage data from the customer service system to prepare reports to monitor arrearage levels. In some circumstances, miscommunications can occur, and the arrearage data being captured could include these credit balances which falsely reduces the total arrearage amount. To ensure that management is reviewing accurate arrearage data, Revenue Recovery must ensure that IT is aware that account credits for these special programs should be excluded from provided data.

Additionally, CPA's CAP participation rate was compared to the same panel of Pennsylvania NGDCs for the years 2016-2018. As shown in Exhibit VIII – 7, CPA's CAP participation rate was lower than the panel average over the period.

Exhibit VIII – 7
Columbia Gas of Pennsylvania, Inc.
Panel Comparison – CAP Participation Rate
For the Years 2016-2018

	2016	2017	2018
Peoples	32.40%	29.20%	62%
PECO-Gas	71.50%	74.60%	79%
NFG	30.90%	31.30%	34.50%
Peoples-Equitable	30.30%	29.00%	64.70%
UGI-Gas	22.50%	24.40%	25.80%
UGI Penn Natural	24.70%	24.40%	26.20%
Average of Panel	35.38%	35.48%	48.70%
CPA	29.90%	32.80%	34.90%

Source: 2016-2018 USP & Collections Reports and auditor analysis

Not realizing the effects to the integrity of arrearage data being used to manage arrearage levels as well as not using the available panel comparison data for average arrearage amounts and CAP enrollment rates may have resulted in excessive arrearage levels CPA experienced throughout the audit period. Had CPA maintained arrearage levels like that of the panel average during the period 2014-2018, it would have realized an average annual arrearage reduction of approximately $4.6 million. This equates to a similar reduction in average annual borrowings for the same period. This is based on the difference in arrearage levels from the panel multiplied by the number of customers in debt for the respective years as shown in Exhibit VIII – 8. A $4.6 million reduction in annual borrowing from NiSource Inc.'s Money Pool at 2% (as of January 2018) would result in an annual savings of approximately $92,000 in interest expense.

Exhibit VIII – 8
Columbia Gas of Pennsylvania, Inc.
Potential Reduced Borrowing
For the Years 2014-2018

	2014	2015	2016	2017	2018	
Difference in Arrearages	$ 89.65	$ 161.09	$ 180.37	$ 186.19	$ 189.64	
No. of Customers in Debt	32,770	29,830	27,691	26,619	27,327	**5-Year Average $4,575,251**
Reduction in Borrowing	$2,937,831	$4,805,315	$4,994,626	$4,956,192	$5,182,292	

Source: 2014-2018 USP & Collections Reports and auditor analysis

3. Revenue Recovery has not developed net collection performance goals with which to manage its third-party collection efforts.

A review of third-party collection activities determined that Revenue Recovery does not set net collection goals to manage its third-party collection efforts. Instead, Revenue Recovery monitors third-party collection agency performance by comparing gross collection performance of third-party collection agencies to performance thresholds. Revenue Recovery's performance thresholds are based on a monthly rolling average of the collection agencies' performance for the prior three years.

Exhibit VIII – 9 shows each agency's 2018 gross collection performance as compared to Revenue Recovery's calculated performance threshold, by month. Gross collection performance does not take into consideration the commissions paid to the agencies which can inflate perceived performance. Therefore, collection goals should be based on net collection results to evaluate actual recoveries. Exhibit VIII – 10 shows the combined early-out/primary collection performance for the period 2014-July 2019, and Exhibit VIII – 11 shows the secondary collection performance for the period 2014-July 2019.

Exhibit VIII – 9
Columbia Gas of Pennsylvania, Inc.
Gross Collections Results Compared to Threshold
For the Year 2018

Early-Out:												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Agency 1	15.13%	19.31%	15.40%	8.53%	8.39%	8.98%	8.24%	7.80%	9.91%	8.52%	7.89%	7.20%
Threshold	**14.4%**	**15.5%**	**11.6%**	**10.3%**	**7.4%**	**7.7%**	**7.5%**	**7.7%**	**8%**	**7.9%**	**8.7%**	**8.5%**
Primary:												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Agency 5	7.82%	6.03%	10.6%	7.29%	6.77%	7.16%	6.19%	7.89%	7.58%	3.41%	3.91%	1.59%
Agency 6	6.75%	10.9%	7.57%	8.56%	9.93%	4.90%	4.27%	4.56%	5.25%	2.62%	5.36%	8.05%
Agency 4	4.01%	3.07%	4.53%	4.57%	2.60%	3.35%	3.07%	4.69%	5.7%	5.12%	2.02%	1.68%
Threshold	**4.5%**	**5%**	**6.9%**	**6.9%**	**6.7%**	**5.3%**	**5%**	**5.8%**	**4.7%**	**4.2%**	**3.9%**	**3.7%**
Secondary:												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Agency 2	2.72%	2.26%	1.58%	1.41%	1.83%	1.32%	.83%	1.32%	1.69%	1.42%	1.68%	2.1%
Agency 3	2.57%	2.11%	2.88%	1.76%	1.71%	4.61%	1.47%	.92%	.31%	4.28%	2.09%	2.73%
Threshold	**2.5%**	**2.6%**	**2.5%**	**1.5%**	**1.7%**	**1.5%**	**1.7%**	**1.2%**	**1.4%**	**1.2%**	**1.2%**	**1.8%**

Source: Data Requests CS-34 and CS-88

Exhibit VIII – 10
Columbia Gas of Pennsylvania, Inc.
Combined Early-Out/Primary Collection Performance
For the Period 2014-July 2019

	Placed	Gross Collection	Commission	Net Collection	Net Collection %
2014	$ 13,420,083	$ 644,515	$ 78,841	$ 565,674	4.22%
2015	15,081,307	1,029,163	128,531	900,632	5.97
2016	11,739,254	738,202	91,849	646,353	5.51
2017	11,857,985	779,700	96,703	682,997	5.76
2018	13,539,929	924,951	111,499	813,452	6.01
Partial 2019	8,445,679	477,435	43,020	434,415	5.14
Total	**$ 74,084,237**	**$ 4,593,966**	**$ 550,443**	**$ 4,043,523**	**5.46%**

Source: Data Requests CS-34, CS-88, and auditor analysis

Exhibit VIII – 11
Columbia Gas of Pennsylvania, Inc.
Secondary Collection Performance
For the Period 2014-July 2019

	Placed	Gross Collection	Commission	Net Collection	Net Collection %
2014	$ 42,316,742	$ 153,674	$ 40,636	$ 113,038	0.27%
2015	16,868,156	161,493	40,634	120,859	0.72
2016	12,966,698	153,393	37,604	115,789	0.89
2017	11,532,018	133,473	31,577	101,896	0.88
2018	10,441,977	137,049	32,725	104,324	1.00
Partial 2019	8,389,934	57,914	14,359	43,555	0.52
Total	**$ 102,515,525**	**$ 796,996**	**$ 197,535**	**$ 599,461**	**0.58%**

Source: Data Requests CS-34 and CS-88 and auditor analysis

Developing and implementing net collection goals provides meaningful criteria with which to evaluate collection results and to motivate third-party collection agencies to improve. Benchmarking the goals for net collection performance of collection agencies with the goals established at similar utilities is a useful way to set goals that are reasonable within the current industry environment. The auditors have seen other NGDCs with net collection goals of 8%-10% for primary collections.

If, at a minimum, CPA had achieved net collections of 8% on its combined early-out/primary placements, it could have realized an additional $2,061,918 in early-out/primary net collections over the reviewed period (or approximately $344,000 per year). Furthermore, if CPA had achieved net collections of 1% on its secondary placements, it could have realized an additional $389,069 in secondary net collections over the reviewed period (or approximately $65,000 per year). Estimated improvement in overall net collections could have been $2,450,987 over the reviewed period (or approximately $408,000 per year). Exhibit VIII – 12 shows the calculation of potential additional collections if CPA were to have achieved the 8% net collection goal for early-out/primary collections and 1% net collection goal for secondary collections. It is likely that these savings would be included in the savings discussed in Finding and Conclusion No. 2 of this chapter.

Exhibit VIII – 12
Columbia Gas of Pennsylvania, Inc.
Estimated Potential Collections
For the Years 2014-2019

	Placed ($)	Net Collections (%)	Net Collections ($)	Goal Net Collection (%)	Goal Net Collection ($)	Potential Additional Collection ($)	
Early-out/Primary	$ 80,549,842	5.44%	$4,382,069	8%	$6,443,987	$2,061,918	**Annual Average $408,498**
Secondary	$102,515,525	0.63%	$ 663,368	1%	$1,052,438	$ 389,069	
Total			**$4,642,984**			**$2,450,987**	

Source: Data Request CS-88

4. NiSource Corporate Services Company does not have a documented theft of service program.

NCSC stated it does not have a documented theft of service (TOS) program. A documented TOS program provides guidance to those responsible for preventing, detecting, reporting, and prosecuting instances of TOS. There are fragmented procedures in place for when there are suspicions or visible signs of TOS, but they have not been organized into a comprehensive program. NCSC has developed a TOS handbook, that is used for training purposes for some departments; however, there is no official training course, and the handbook does not organize all procedures and responsibilities into one documented TOS program resulting in increased risk for process gaps, duplicated efforts, and missed opportunities to identify and recover from instances of TOS. NCSC indicated its plans are to develop a TOS training course by the end of 2020.

5. Customer service representative turnover is higher than at other like utilities.

Turnover for CSR positions at CPA was 31%, 20%, and 29% for the years 2017, 2018, and 2019; respectively. The auditors have seen CSR turnover rates averaging around 14% at other comparable utilities. Turnover data prior to 2016 was not available due to outsourcing. Prior to insourcing in 2016, a third-party vendor provided customer contact center services at the Smithfield, PA facility. Those who had worked under the third-party vendor reported extremely high CSR turnover primarily due to less than competitive pay which resulted in low morale and staff being able to easily find more lucrative working conditions/terms elsewhere.

Management acknowledged that high CSR turnover remained a challenge which motivated the implementation of a tiered hierarchy which included more leadership levels from Senior CSR up through Manager, Customer Contact Center to provide more growth opportunities within employees' careers to help retain talent. Subsequently in June 2019, a third-party service application was implemented to assist in further reducing CSR turnover. Because the retention application was only recently implemented in June 2019, program efficacy in the decrease of CSR turnover has yet to be realized. CCC management has indicated that there are several analysis points built into the program timeline at which program efficacy will be evaluated.

Maintaining a reasonable CSR turnover rate is crucial to an efficient and cost-effective customer contact center. Turnover increases recruitment and training costs, creates a loss of institutional knowledge, and lowers morale which decreases productivity. As a conservative estimate, the cost of losing a CSR can range from 1.5-2.0 times the employee's annual salary.[7] The average annual salary of a CSR is about $30,000. If CPA had reduced its 2019 turnover rate for CSRs from 20% to 14%, it could have realized an annual savings of about $180,000 to $240,000.

Recommendations

1. **Develop and implement a review schedule to ensure the metering and billing policies and procedures are kept current.**

2. **Implement various strategies to reduce arrearage levels such as increasing CAP enrollment and effective calculation of internal arrearage data to appropriately monitor and manage arrearage performance.**

3. **Develop and implement net collection goals with which to manage third-party collection efforts by benchmarking with similar utilities.**

4. **Develop and implement a documented TOS program.**

5. **Complete an analysis of the third-party retention application to evaluate program efficacy in reducing CSR turnover rates by December 31, 2020.**

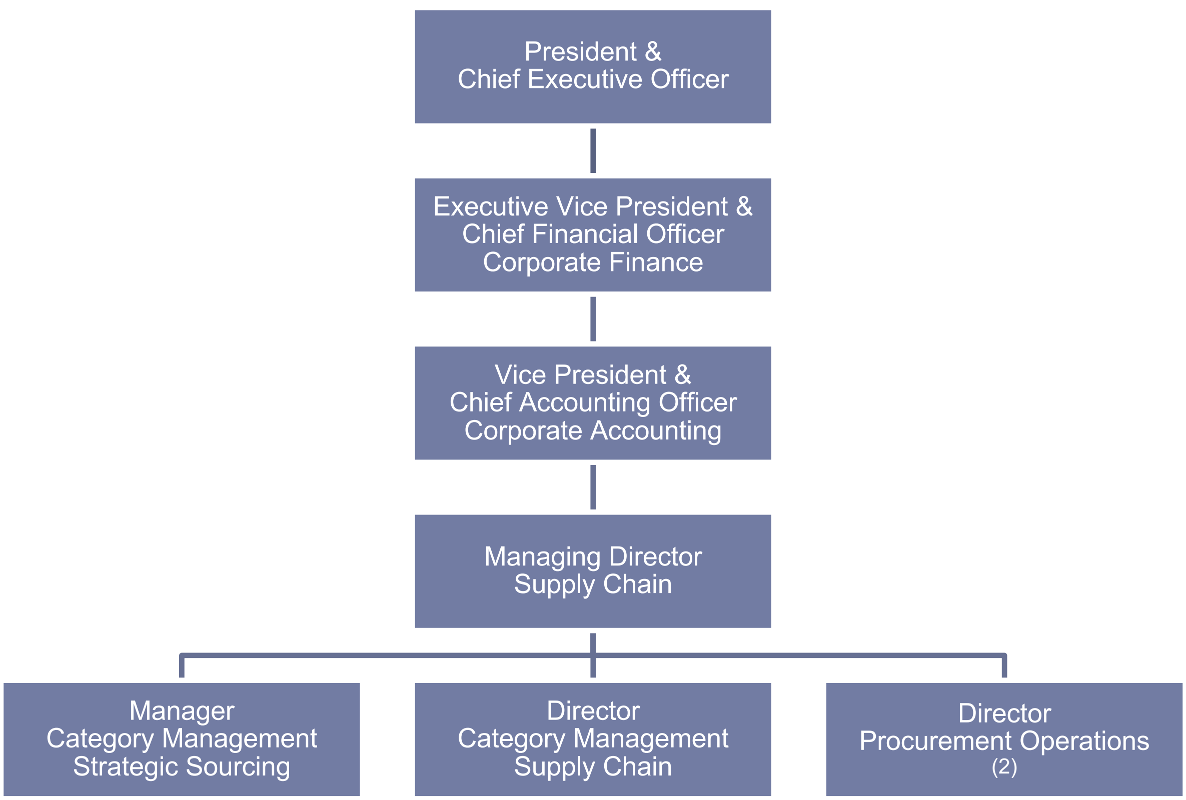
[7] https://www.linkedin.com/pulse/20130816200159-131079-employee-retention-now-a-big-issue-why-the-tide-has-turned

IX. PURCHASING AND MATERIALS MANAGEMENT

Background

Columbia Gas of Pennsylvania, Inc. (CPA) relies upon NiSource Corporate Services Company (NCSC) for purchasing and materials management functions. Exhibit IX – 1 displays the organizational structure for the purchasing and materials management functional area within NCSC. The Managing Director of Supply Chain is responsible for these functions. Supply Chain is organized into two business units: Category 2 Management and Procurement Operations. Category Management is focused on strategic sourcing for key spend categories (i.e., gas construction, gas materials, etc.). Areas of responsibility include long-term strategy and planning, negotiations with suppliers, strategic sourcing, and governance of contracts. Procurement Operations is focused on transactional procurement (i.e., requests for proposals (RFP), contracts, and purchase orders) for direct and indirect services and materials across NiSource Inc. Generally, Category Management is responsible for long-term resources and Procurement Operations is responsible for day-to-day resources.

Exhibit IX – 1
NiSource Corporate Services Company
Supply Chain Organization
As of December 2019



Source: Data Request EM-3

NCSC maintains policies and procedures to direct the methodology behind the acquisition of supplies and materials. Appropriate forms and documents related to acquisitions must be completed in compliance with NCSC's Corporate Accountability Policy, Requisition and Disbursement Approval Levels Policy, and Supplier Diversity Policy. Supplier sourcing is dependent on type and cost of needed products or services. Policies govern when competitive bids, preferred supplier designation, or direct awards are used for sourcing. Competitive bids are used for goods and services that are estimated to cost in excess of a predetermined dollar amount. Preferred suppliers are designated at the request of a business unit, or occasionally at the request of supply chain, based on overall benefit. Direct awards are permissible if the aggregate commitment with the supplier is less than a predetermined dollar amount. Furthermore, spending is governed by a delegation of authority table outlining appropriate approval requirements.

A third-party integrated material supplier, MRC Global, is used for all capital, operating and maintenance (O&M), and emergency related activities. Orders are placed with MRC Global in anticipation of upcoming jobs or to replenish depleted truck stock. Preapproved materials (e.g., pipe, valves, fittings, etc.) are procured from manufacturers and are warehoused by MRC Global. While capital materials are delivered to job sites, routinely used O&M materials are stored in bins at each of CPA's operations centers[8]. These bins are owned and stocked by MRC Global. NCSC's Work Management System interfaces with MRC Global's system so that as CPA uses material from these bins, material data is recorded directly to job orders and CPA is then charged for the respective material usage. Controls are in place within both systems to enable accurate ordering, receipting, and invoicing of materials via stock numbers, units of measure, and pricing. The stock in these bins is typically evaluated once a week by MRC Global, but this can occur more frequently if needed.

CPA's purchasing and materials management organization has been integrated with MRC Global for several decades. The auditors reviewed the contract renewal and consideration process utilized by NCSC to determine if pricing continues to be reasonable. NCSC is currently approximately halfway through a five-year contract with MRC Global. Before this contract was renewed, an outside party performed a thorough analysis which determined that NCSC is paying fair market rates, and in some instances better than market rates, for material acquisition.

NCSC actively seeks out qualified Minority, Women, and Disadvantaged Business Enterprises (MWDBE) vendors for potential RFP subsidiary solicitations. The NiSource Inc. goal for MWDBE usage for the entities across its footprint is 8.5% except for those entities which are required to achieve a specific MWDBE usage rate as specified by its respective regulating entity. CPA is one of NiSource Inc.'s top performing distribution companies for diverse spending with a range of 17% to 21% per year between 2014 and 2018. Supplier diversity efforts are included throughout the supply chain process including efforts to utilize MWDBEs in RFPs, tracking and reporting, and MWDBE engagement opportunities and memberships.

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[8] CPA's operations centers are in Bridgeville, Monaca, Uniontown, and York (see Exhibit VII – 1 for a map of the operations centers)

Findings and Conclusions

Our examination of the purchasing and materials management functional area included a review of assigned responsibilities, policies and procedures, information systems, reporting capabilities, inventory controls, and third-party material supplier oversight. Based on our review, nothing came to our attention that would lead the auditors to conclude that areas reviewed were not being addressed adequately.

Recommendations

None

COLUMBIA GAS OF PENNSYLVANIA, INC.

X. EMERGENCY PREPAREDNESS

Background

On June 11, 2005, Regulations at 52 Pa. Code § 101 (Chapter 101) went into effect that require jurisdictional utilities to develop and maintain written physical security, cyber security, emergency response, and business continuity plans to protect infrastructure within the Commonwealth of Pennsylvania and to ensure safe, continuous, and reliable utility service. A jurisdictional utility is required to maintain these "emergency preparedness" plans and annually file a Self-Certification Form to the Pennsylvania Public Utility Commission (PUC or Commission) documenting compliance with Chapter 101. This form is available on the Commission website and is comprised of the questions as shown in Exhibit X – 1.

Exhibit X – 1
Pennsylvania Public Utility Commission
Public Utility Security Planning and Readiness Self Certification Form

Item No.	Classification	Response (Yes–No–N/A)
1	Does your company have a physical security plan?	
2	Has your physical security plan been reviewed in the last year and updated as needed?	
3	Is your physical security plan tested annually?	
4	Does your company have a cyber- security plan?	
5	Has your cyber security plan been reviewed in the last year and updated as needed?	
6	Is your cyber security plan tested annually?	
7	Does your company have an emergency response plan?	
8	Has your emergency response plan been reviewed in the last year and updated as needed?	
9	Is your emergency response plan tested annually?	
10	Does your company have a business continuity plan?	
11	Does your business continuity plan have a section or annex addressing pandemics?	
12	Has your business continuity plan been reviewed in the last year and updated as needed?	
13	Is your business continuity plan tested annually?	

Source: Public Utility Security Planning and Readiness Self-Certification Form, as available on the PUC website at http://www.puc.state.pa.us/general/onlineforms/pdf/Physical_Cyber_Security_Form.pdf.

Due to the sensitive nature of the information reviewed, specific details are not revealed in this report but rather the generalities of the information reviewed are summarized below.

The auditors reviewed the most recent (i.e., 2018) Self-Certification Forms submitted by NiSource Inc. on behalf of Columbia Gas of Pennsylvania, Inc. (CPA or company). The auditors' examination of NiSource Inc.'s and CPA's emergency preparedness included a review of the physical security plans (PSP), cyber security plans (CSP), emergency response plans (ERP), and business continuity plans (BCP); additionally, any associated manuals and security measures. The plans and related manuals were deemed complete and appropriate. The auditors also performed inspections at a sample of NiSource Inc.'s facilities including CPA's headquarters and various remote field locations without noted exception.

NiSource Inc. and CPA test the PSP, CSP, ERP, and BCP at least annually and, in some instances, multiple times per year. A review is completed to ensure each plan has been tested, results of testing were evaluated, and the necessary corrective measures were taken. The plans are updated following testing and/or review. The responsible parties as well as a synopsis of duties are as follows:

- **PSP** – Director of Corporate Security and Manager of Security Operations – sets guidelines to address the multitude of physical security issues throughout the NiSource, Inc. footprint; uses the 5-step approach: Preparedness, Prevention, Protection, Response, Recovery.

- **CSP** – Chief Information Security Officer– in addition to day-to-day cyber security operations, the plan provides structure and guidance for responding to information security incidents by detailing current resources for rapid response, effective recovery, communication chains, and coordinated action.

- **ERP** – Senior Vice President of Gas Operations Support and Technical Services – provides a foundation for emergency management such as preparedness, mitigation, response, and recovery actions to preserve public safety and welfare.

- **BCP** – Director of Corporate Compliance Business Continuity – prepares for and handles any significant event that would cause an inability to conduct normal business operations.

The auditors reviewed policies, procedures, and general practices related to physical and cyber security. Established plans, encompassing policies, and the cyber security awareness program ensure CPA maintains a safe, reliable, and customer-focused environment. For additional information regarding cyber security, please refer to Chapter IX – Information Technology.

Findings and Conclusions

Our examination of the emergency preparedness functional area included a review of the PSP, CSP, ERP, BCP, vulnerability assessments, and all associated security measures. Based on our review of the companies' emergency preparedness efforts, no evidence came to our attention that would lead the auditors to conclude that the areas reviewed were not being adequately addressed.

Recommendations

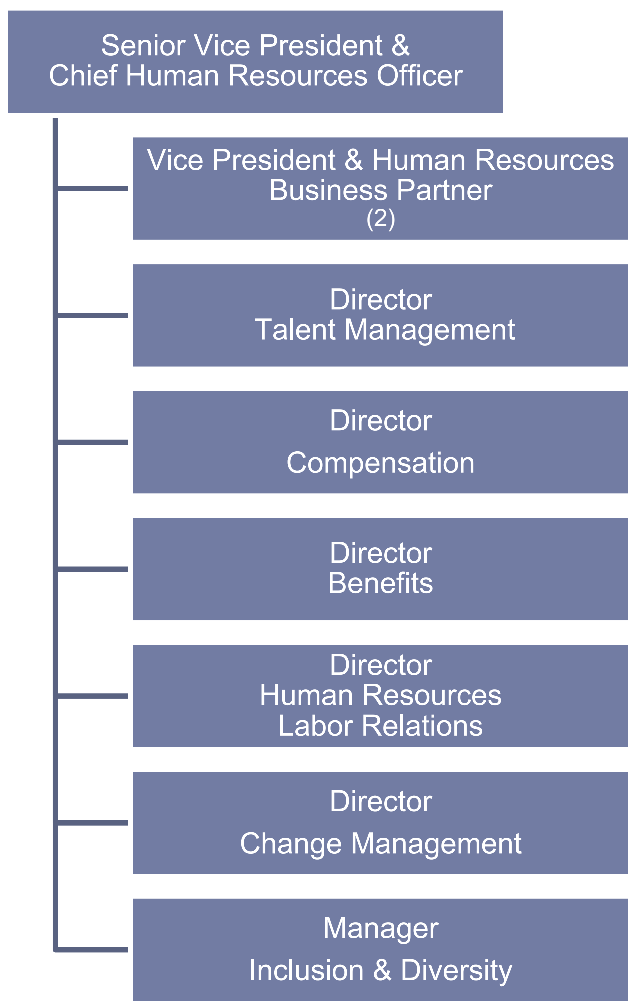
None

XI. HUMAN RESOURCES

Background

As discussed in Chapter II – Background, Columbia Gas of Pennsylvania, Inc. (CPA or company) is a subsidiary of NiSource Gas Distribution Group, Inc. (NGD) which is owned by the energy holding company, NiSource Inc. The human resources (HR) function is provided to CPA through the NiSource Corporate Services Company (NCSC); however, it is bifurcated between a local state HR group dedicated to CPA operations and various HR business units which provide HR support to all NiSource Inc. entities. Shown below in Exhibit XI – 1 and Exhibit XI – 2 are the organizational structures of both the corporate-level HR function and the local state HR group of NCSC.

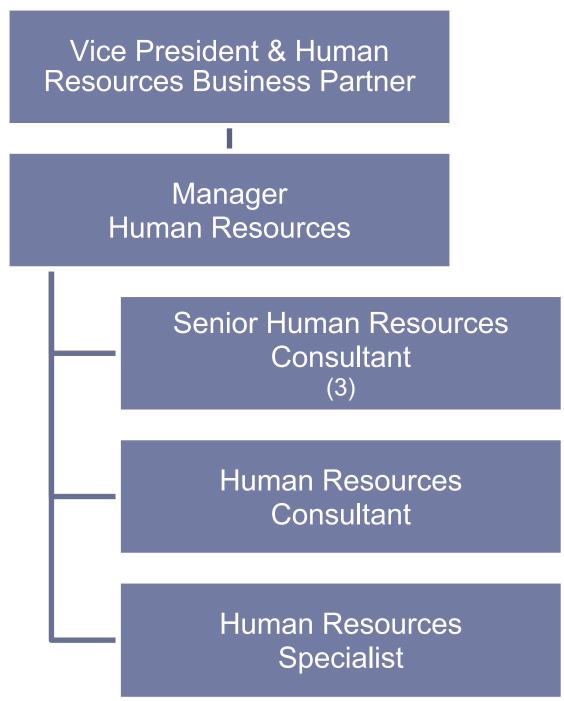
Exhibit XI – 1
NiSource Corporate Services Company
Human Resources Function Organization
As of December 2019



Source: Data Request EM-3

Along with the traditional HR functions, NCSC has broadened its focus, relative to HR, by developing several cultural and strategic HR business units such as Change Management, Inclusion & Diversity, and most recently, the newly developed Vice President & Human Resources Business Partner (HRBP) role. Change Management enhances the employees' experiences associated with the multitude of changes that entities go through relative to both industry and corporate culture. Inclusion & Diversity has grown from a mere matter of consideration to a concerted effort to ensure all employees have both voice and opportunity. And the HRBP role has been developed to ensure that HR related considerations are used in the strategic planning processes of the organization. And as is depicted in Exhibit XI – 2 below, the HRBP is the link between the local state human resources group and the corporate HR function.

Exhibit XI – 2
NiSource Corporate Services Company
Local State Human Resources Group Organization
As of December 2019



Sources: Data Requests EM-2 and EM-85

The main roles of the local state HR group are managing the day-to-day employee relation issues of the unionized employees of CPA along with providing implementation support of the projects and goals being initiated by the corporate HR business units. The Manager, HR; two of the three Senior HR Consultants; and the HR Specialist are housed at the CPA Headquarters in Canonsburg, PA and support those employees who work out of the CPA Headquarters and the surrounding northern, southern, and western regional employees including those who work at the Bridgeville, Monaca, and Uniontown Operations Centers. The third Senior HR Consultant is housed in the York Operations Center supporting the eastern regional employees and the HR Consultant is housed in the Smithfield Customer Call Center (CCC) supporting the employees there.

CPA's compensation strategy includes base pay plus an available earned incentive component. The base pay of unionized employees' compensation is defined by the current bargaining agreement and the incentive component is defined by an annual NiSource Corporate Incentive Plan (Incentive Plan). The base pay for non-unionized and exempt employees' compensation is aligned with current industry levels as determined by participation in a third-party market compensation study at least every other year while the incentive component is defined by the Incentive Plan. All employees participate in the annual Incentive Plan to reward them for individual achievements. Additionally, the company provides a competitive benefits package including medical, dental, and vision coverage plans along with short and long-term disability, life insurance, and retirement savings offerings.

NiSource Inc. currently uses Peoplesoft HR/Payroll 9.1 throughout the corporation; however, it is currently engaged in a human capital management (HCM) project which includes in scope the replacement of the HR information system. Tentative implementation for the core system (payroll, recruiting, and advanced HR analytics) is planned for December 2020. Subsequent phases will be systematically rolled out thereafter at unspecified intervals. Additional functionality expected to be gained includes talent management, mobile application availability, enhance self-services, among others.

As expected from a complex organization the size of NiSource Inc., there are multifaceted training curricula developed and overseen by different business units within the organization to ensure all developmental needs for the various roles are met. The foundational trainings offered throughout the organization covering topics such as ethics; general employment relations, policies, and procedures; and personal safety and security are typically provided throughout the organization utilizing the learning management system (LMS) provided by the performance support business unit within NCSC. Job-duty specific training appropriate for delivery through an online format is developed and offered via the LMS as well.

As of December 2019, there were approximately 6,200 learning sessions available within the LMS. These sessions could be assigned by HR, regulatory compliance, or an employee's supervisor as developmental or compliance needs arise. In addition, there are classroom-delivered as well as practical, hands-on training curriculums available for those specialty topics requiring in-person interactive processes. These may be held in facility conference rooms, onsite at operations centers, or at one of NiSource Inc.'s modernized technical training centers. In 2016, the Monaca Training Center was opened in Pennsylvania to serve the technical needs of both CPA and Columbia Gas of Maryland, Inc. The technical training centers are equipped with both classroom and hands-on learning facilities, testing facilities to administer industry required certification testing, and various work task simulation stations.

Corporate succession planning activities are performed annually at the officer level and are optional for manager and director positions. Successors are identified as ready now or within 1-3 years. Every candidate cited within the corporate succession plan confirms interest in the opportunity and commits to participating in development activities toward the identified role. On the local state level, the local state HR group uses a program called Success Factors to rank exempt employees as ready now, ready in 1-3 years, or ready within 3-5 years for advancement and action plans are made to develop those individuals for future opportunities.

In addition to internal development, HR, both at the corporate level and the local state level, participates in active recruitment activities to continue to attract new talent. The NiSource Inc. website is the front-line recruiting tool which provides access to all job postings throughout the organization. The local state HR group typically focuses on field operations staffing needs by participating in approximately 25 career fairs including some specifically geared toward veteran job seekers, making presentations at regional high schools and technical schools, and partnering with trade organizations.

The Pennsylvania Public Utility Commission (PUC or Commission) has encouraged utilities to proactively improve diversity in their workforce and purchasing efforts for more than two decades. In February 1995, the Commission adopted Chapter 69 regulations which encouraged utilities to include diversity efforts as a component of their business strategy. Since March 1997, the PUC has required utilities to file annual reports that identify their efforts in improving diversity in their workforce and purchasing efforts. CPA filed its most recent annual diversity report to the Commission on March 1, 2019 for the year ended December 31, 2018 and continues to be timely with annual diversity report filings. Included in the diversity report are sections related to HR and purchasing. More information regarding CPA's diversity procurement efforts is available in Chapter IX – Purchasing and Materials Management.

CPA implemented an Inclusion and Diversity Program in 2010 with the vision, "To foster an inclusive environment that values and respects the diversity of our customers, communities, and employees by encouraging people to be themselves, achieve their full potential, and contribute toward NiSource's aspiration to become the premier energy company in our industry." More recently it has expanded these efforts by prioritizing an HR business unit around inclusion and diversity, as shown in Exhibit XI – 1, which continues to champion these efforts.

The NCSC HR function continuously performs needs assessments to ensure initiatives and goals being developed for the HR business units are meaningful and add value to the annual strategic business plans. A recent result of this process was the decision to insource the CCC to ensure the work environment for those employees was consistent with the corporate-wide initiative to become a best-in-class employer and to ensure the prioritization of customer experience and satisfaction. Performance levels at the CCC were consistently substandard under the service management of the third-party provider and the needs assessment highlighted employee dissatisfaction as the root cause of this problem. NCSC recognized the need to bring this operation in-house to initiate positive change. When the CCC was insourced in 2016 (more details are provided in Chapter VIII – Customer Service), the decision was made to add the full-time HR Consultant to support CCC employees. During follow-up analysis conducted in 2018, two full-time recruiters were hired to focus on appropriate talent acquisition to improve a higher than desired turnover rate.

In October 2019, the HR function began into its first stage planning activities through the "HR Journey" to develop the department into a stronger strategic business partner. Work teams were identified to develop the five following HR function advancements:

- Establish HR Business Partners – translate business strategy into people strategy through partnering on work such as organizational design, talent development, succession, and workforce transition planning

- Define HR Service Delivery Tiers – provide services through lens of employees and leaders using preferred methods of interaction (e.g., phone, in-person, mobile)

- Build Our Workforce & Talent Analytics Capabilities – manage human capital as a strategic asset by leveraging HR dashboards, people metrics, and evidence-based decision making

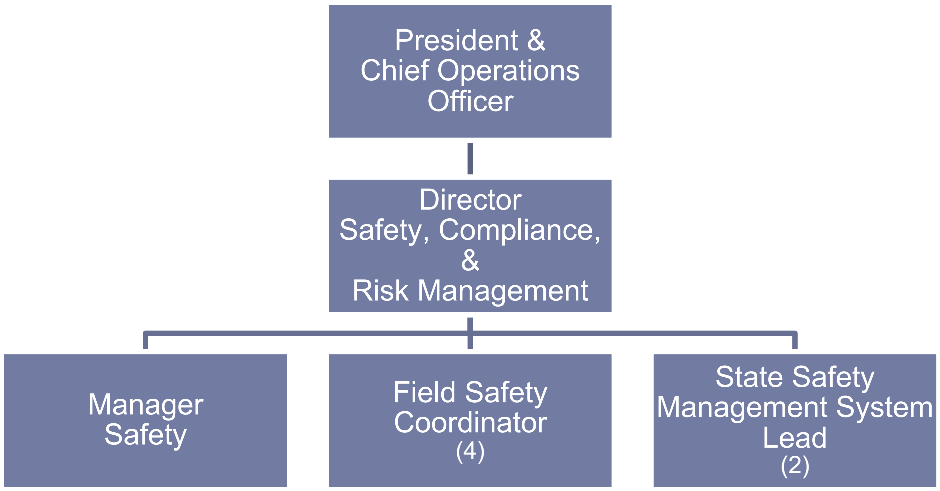
- Streamline Key Processes and Gain Synergies – drive cutting edge best practices in employee relations and talent acquisition, among others

- Prepare for the Implementation of the new HCM System – enable future state service delivery models and processes

This chapter also includes an overview of the safety culture at NiSource Inc. including specific initiatives of CPA. In 2015, the American Petroleum Institute published its Recommended Practice 1173 which supports the use of a Safety Management System (SMS) designed to prevent employee and contractor illness and injury. NiSource Inc. wanted to be an early adopter of this strategy and began systematically implementing various components of an SMS at a conservative interval; however, the SMS deployment was accelerating beginning in 2019 to further mitigate identified risk. Since 2015, NiSource Inc. has been prioritizing the safety culture throughout the organization.

On April 1, 2019, management of the safety programs has shifted from a centralized business unit to a local state responsibility. CPA created a new position of Director of Safety, Compliance, & Risk Management, who reports directly to the President of CPA, to lead the local state safety team. The organizational design of the local state safety team was strategically developed to avoid the influence of the performance pressures of the operations and construction functions. CPA is committed to focusing on safety as a top-tier priority. The organization of the local state safety team is shown below in Exhibit XI – 3. There remains a centralized safety business unit within NGD led by the Senior Vice President, Safety, Environmental & Training along with the Director, Environmental Health & Safety and the Manager Construction Field Safety which partners with the local state safety team.

Exhibit XI – 3
Columbia Gas of Pennsylvania, Inc.
Local State Safety Team Organization
As of December 2019



Source: Data Requests EM-2 and HR-21

NiSource Inc., including CPA, participates in the traditional compliance activities and annual trainings related to defined topics as required for those working in the natural gas industry and by OSHA as well as participates in specialty field tool recertification and first aid instruction. CPA has also incorporated many additional safety initiatives to emphasize the safety culture. Some of these initiatives, offered to both employees and contractors, include but are not limited to:

- Driving safety programs including professional driving modules and policy testing delivered through the LMS, supervisor ride-along observations, automated driving behavior monitoring technology installed on fleet vehicles, and other in-house and third-party provided initiatives

- Ergonomics programs including computer-based learning delivered through the LMS, workspace assessment/redesign with optional sit/stand workstations, third-party provided physical and occupational therapies, and other physical movement training

- Newly developed safety-related training and development curriculum delivered during new hire and refresher training sessions

- Just Culture Performance Management Model which emphasizes the open forum that employees should report all safety hazards, near misses, and injuries without fear of retribution or retaliation

- National Safety Council Safety Barometer Survey including results-driven employee action planning for continuous improvement

- Newly developed safety messages and policies such as the 12 life-saving rules and beginning meetings with a safety moment

- Executive Observation Program which requires executives of all levels to visit job sites and record safety observation

In addition to the sample of initiatives above, the main component of the SMS, the Corrective Action Program (CAP)[9], has also spurred vigor into revamping the safety culture. Every employee and contractor throughout NiSource Inc. is encouraged to participate in a comprehensive risk identification process which provides multiple formats to disclose perceived risks within the workplace. Every identified risk is evaluated, assigned a point of accountability, and resolved through the CAP. As of October 31, 2019, there were 158 submitted risks being processed through the CAP.

Although there are key safety personnel who develop and manage current programs and initiatives, the responsibility for the adoption of the safety culture is companywide. There are many employees within the organization who serve on one or more of the active safety committees at the local state level. These committees include:

- Local Operations Safety Teams – a team of front-line workers is active at each operating center in Pennsylvania as well as at the CPA headquarters to act as a safety liaison between staff and management

- State Operations Safety Team – representatives from each Local Operations Safety Team collaborate monthly to act as a safety liaison between staff and upper management

- State Construction Safety Team – representatives from the state construction function serve to act as a safety liaison between staff and management

- State Service Injury Prevention Team – representatives of the operations staff meet to review near miss and injury statistics to recommend injury prevention strategies

- Cooperative Contractor Safety Committee – representatives from CPA's construction staff; NiSource Inc.'s health, safety, and environmental function; and contractors meet to discuss issues pertaining to contractors' safety

- Subcommittee for Paving Contractor Safety – created to address the unique safety topics associated with restoration work

[9] Regulated utilities typically use the standardized acronym, CAP, to refer to the Customer Assistance Program offered through universal services plans (as referenced in Chapter VIII – Customer Service); however, CAP is the commonly used acronym for the SMS component, Corrective Action Program, within the safety industry as well

- State Risk Table – members of senior management tasked with the review of perceived risks submitted through the CAP and the development of steps toward resolution

Findings and Conclusions

Our examination of the HR functional area included a review of assigned responsibilities, policies and procedures, the HR information system capabilities, training and employee development, compensation and benefits, diversity programs, and safety initiatives. Based on our review, CPA should initiate or devote additional effort to improving the efficiency and/or effectiveness of the HR functional area by addressing the following:

1. Safety metric performance declined in 2018 and 2019 as compared to 2014-2017.

Exhibit XI – 4 shows CPA's safety performance as demonstrated through OSHA reportable metrics. The first metric presented is the Total Recordable Incident Rate which represents CPA's annual safety performance by calculating the number of OSHA-recordable incidents per 100 employees. OSHA-recordable injuries are accidents that result in medical treatment beyond first aid, at least one day of either lost time or restricted duty excluding the day of injury, or a fatality. The second metric, Days Away/Restricted or Transferred (DART) Rate, represents the number of recordable incidents that resulted in days away from work; restricted work activity; and/or job transfer that the company has experienced per 100 employees over the calendar year. The third metric is the Preventable Motor Vehicle Accident (PMVA) Rate which shows how many preventable motor vehicle accidents the company has experienced annually per hundred thousand miles driven. Lower values indicate better performance for each metric.

Exhibit XI – 4
Columbia Gas of Pennsylvania, Inc.
Safety Performance Metrics
For the Years 2014-2019

Safety Metric	2014	2015	2016	2017	2018	2019
Total Recordable Incident Rate	0.71	1.92	1.57	0.78	3.01	1.97
DART Rate	0.57	0.77	0.94	0.31	2.47	1.27
PMVA Rate	2.57	2.68	1.63	1.79	1.59	2.06

Source: Data Requests HR-40 and HR-43

As routine practice, the auditors review safety performance as measured by the above defined criteria. Upon review of CPA's performance throughout the audit period, a decline in performance was noted in 2018 and 2019 as compared to 2014-2017. The auditors compared CPA's safety performance to both its internally designated performance targets as well as to an external benchmarking panel administered by the

American Gas Association (AGA). CPA's internally designated performance goal for 2018, and then again in 2019, was to show improvement over 2017 safety metric performance and to achieve top decile performance within the AGA benchmarking panel. CPA's safety metric performance was ranked top quartile in all three metrics for 2017; however, in 2018, its Total Recordable Incident Rate ranking dropped to third quartile, its DART Rate dropped to fourth quartile, and its PMVA Rate remained first quartile. Results of the 2019 AGA benchmarking panel were not available at the end of audit fieldwork. CPA did not meet either component of its internally designated performance target for 2018, and although benchmarking panel results were not yet available, CPA did not meet its safety metric rate performance in 2019.

In discussions with the Director of Safety, Compliance, & Risk Management, it was evident that CPA had undergone many changes within its safety culture intensifying in 2018 and 2019 which could provide clarity as to why the reported performance was changing. CPA implemented new programs as well as revised safety policies and procedures (e.g., Just Culture Performance Management Model introduced in 2017) which drastically altered employee behavior so that employees were encouraged to prioritize safety without regard for negative effects on reported safety performance. This is a commendable shift in CPA's overall corporate culture which identifies its employees as its most valued resource.

As described in the background of this chapter, CPA maintains safety committees to evaluate perceived risks; review injuries and near-miss events; and perform root cause analysis to strive for continuous safety performance improvement. It should be noted that although CPA did not meet its internally designated safety performance targets in 2018 and 2019, it showed marked improvement within two of the safety performance metrics from 2018 to 2019.

Having not considered influencing factors when setting safety performance goals has resulted in unrealistic expectations. Although it is a normal business practice to maintain performance goals at previous levels of performance or better, in a situation where major change has occurred, the effects of this change need to be analyzed so that reasonable, challenging performance goals can be developed. Setting unrealistic, unattainable goals only serves to frustrate employees which could result in apathy toward striving to meet future goals.

Recommendation

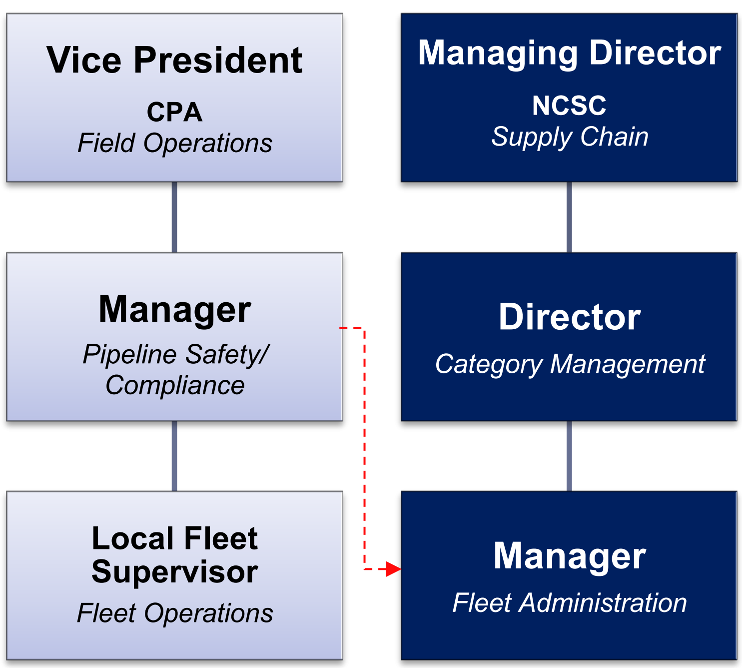
1. **Analyze influencing factors when developing future safety performance targets to ensure goals are set at challenging, attainable levels while continuing to prioritize the safety culture to bolster continuous improvement toward long-term safety performance goals.**

XII. FLEET MANAGEMENT

Background

The Fleet Operations business unit (Local Fleet) of Columbia Gas of Pennsylvania, Inc. (CPA or company) is responsible for, but not limited to, scheduling lifecycle maintenance (routine and repair), identifying equipment needs (including vehicle upfitting), planning and reviewing the annual budget, complying with NiSource Inc.'s vehicle policies, and monitoring local fleet usage. In addition to Local Fleet, NiSource Corporate Services Company's (NCSC) Fleet Administration (Corporate Fleet) is accountable for, but not limited to, governance of Local Fleet, third-party vendor support, vehicle acquisitions, equipment specifications, and supplier service level agreements. A part of Local Fleet's and Corporate Fleet's missions is to provide company-owned vehicles that are safe to operate for employees who are required to drive in order to perform assigned work tasks and functions. Local Fleet works closely with various CPA user departments, particularly other field operations departments (see Chapter VII – Gas Operations), to develop vehicle specifications which most appropriately meet user departments' needs. The Local and Corporate Fleet reporting structure is shown in Exhibit XII – 1.

Exhibit XII – 1
Columbia Gas of Pennsylvania, Inc.
Fleet Reporting Structure
As of January 21, 2020



Source: Data Requests EM-2, EM-3, Interview Request VE-2, and auditor analysis

CPA does not operate garages nor employ mechanics to service and/or repair company vehicles. The company service territory (see Chapter VII – Gas Operations, Exhibit VII – 1) encompasses a large area of Pennsylvania, therefore a central garage may not be a viable or economical option for CPA to perform fleet maintenance. The Local Fleet Supervisor oversees preventive and routine maintenance and repair work utilizing approved auto servicing vendors. Additionally, most fleet vehicles, not including upfitted special orders, are leased which are covered by factory warranties. Vehicles requiring warranty work are picked up and delivered by the dealership.

The CPA fleet consists of passenger cars, sport utility vehicles (SUV), cargo vans, pick-up trucks, specialized construction vehicles (e.g., excavators, skid loaders, backhoes, compressors, forklifts, lawn equipment, and various all-terrain vehicles), and trailers used for transporting construction equipment. Exhibit XII – 2 shows the total number of vehicles and equipment, by type, for CPA at year-end for 2017-2019. The exhibit shows the increase in total number of vehicles assigned to CPA from 727 to 900 over the 3-year period. This increase is, in large part, due to CPA purchasing SUVs. Local Fleet has decided to phase out light-duty and medium-duty trucks, when feasible, to replace with SUVs. The transfer to SUVs is based on cost savings; a savings upward of 50% is realized compared to the cost of light-duty and medium-duty trucks. The use of SUVs does not prohibit the ability of field personal to perform job functions.

Exhibit XII – 2
Columbia Gas of Pennsylvania, Inc.
Fleet Operations
Vehicles and Equipment at Year End 2017, 2018, and 2019

	2017	2018	2019
Compact	3	4	5
Sport Utility	103	122	232
Light-Duty	250	252	262
Medium-Duty	100	114	115
Heavy-Duty	57	63	69
Van	80	81	85
Trailer	9	21	16
Equipment	125	127	116
TOTALS	**727**	**784**	**900**

Source: Data Request VE-5-R and Auditor Analysis

Findings and Conclusions

Our examination of the fleet management functional area focused primarily on a review of the vehicle and equipment acquisition process, including lease versus buy analyses and policies relative to competitive bidding; vehicle and equipment maintenance and repair procedures; and the process for monitoring vehicle and equipment utilization. Based on our review, CPA should initiate or devote additional efforts to improving the efficiency and effectiveness of Local Fleet management by addressing the following:

1. CPA does not use available historical fleet data to effectively trend utilization of company assigned vehicles.

Corporate Fleet contracts with a third-party management solutions provider to provide services to NiSource Inc. subsidiaries. These services include vehicle obtainments, strategic unit cycling, account management, and company vehicle remarketing. In addition, it provides fleet solutions software to record and monitor vehicle and driver statistics. The dashboard provides Local Fleet with a robust source of real-time data points broken into several vehicle groups (e.g., assigned driver, vehicle type, department inventory). The data points include, but are not limited to, distance driven (miles), fuel usage, fuel exception reports, preventative maintenance details, Department of Transportation inspection summaries, vendor repair information, vehicle violations, and vehicle/driver telematics.

Although the fleet solutions software enables CPA to track and monitor fleet inventory, Local Fleet was unable to provide historical trending data for its fleet. Corporate Fleet retains the raw data but does not usually summarize it into a usable resource. Tracking and summarizing historical fleet usage statistics allows a company to trend and identify fleet needs, such as retirement or reassignment, to optimize efficiency. Accurate record keeping and data reporting are necessary to monitor and manage fleet performance. As of December 2019, CPA leases 557 fleet assets that carry a $471,000 monthly payment (base, interest, taxes). As such, CPA may not be maximizing the effectiveness of capital and operations and maintenance fleet programs.

Recommendation

1. Develop and regularly review a historical summary report of annual vehicle utilization data to ensure optimal fleet efficiency.

XIII. INFORMATION TECHNOLOGY

Background

As discussed in Chapter II – Background, Columbia Gas of Pennsylvania, Inc. (CPA or company) is a natural gas distribution company headquartered in Canonsburg, PA that is owned by NiSource Inc. Information technology functions are provided by the NiSource Corporate Services Company (NCSC) which provides services to the parent and all subsidiaries of NiSource Inc.

The Information Technology (IT) functional area is managed by NCSC's Chief Information Officer (CIO). As shown in Exhibit XIII – 1, the CIO reports to the Chief Financial Officer and reporting directly to the CIO are five team members: Director of Continuous Improvement, Technology and Application Support, Chief Information Security Officer of IT Security, Vice President of IT Services, Vice President of IT Infrastructure, and Vice President of IT Applications. IT's mission is to increase focus on business needs and outcomes advancing NiSource Inc.'s capability as a strategic business partner. Duties and responsibilities of the groups and subgroups are summarized below:

- IT Security – **IT Risk & Compliance, IT Security, Identity Access Management** – responsible for, but not limited to, managing cyber security program, automating identity and access management, reducing risk exposure & actively managing vulnerabilities, providing company and contractor cyber awareness programs, and control governance, risk & compliance operations

- IT Services – **Service Management, Portfolio Management, Modernization** – responsible for, but not limited to, overseeing service provider efforts, optimizing process on ITIL[10] framework, developing multiyear modernization plan(s), sourcing, and managing corporate IT portfolio

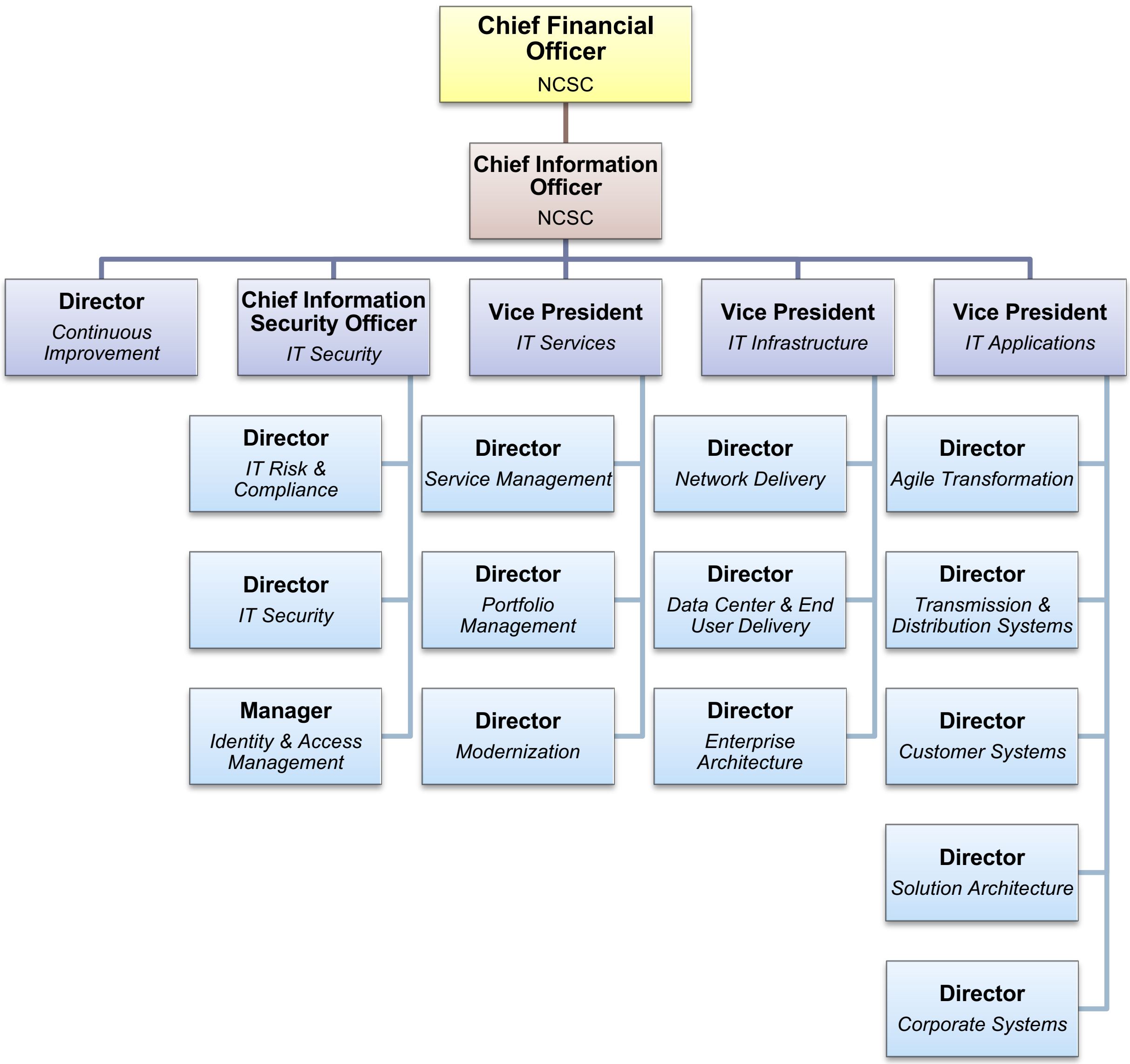
- IT Infrastructure – **Network Delivery, Data Center & End User Delivery, Enterprise Architecture** – responsible for, but not limited to, network, end user, and data center services; network infrastructure; IT disaster recovery; database maintenance; cloud integration; workplace technology deployment

- IT Applications – **Agile Transformation, Transmission & Distribution Systems, Customer Systems, Solution Architecture, Corporate Systems** – responsible for, but not limited to, forming new IT organizational structure, establishing agile methodologies and defining roles, developing applications for operational needs, and information management strategy

- Continuous Improvement – responsible for, but not limited to, reviewing and identifying IT processes and policies to improve efficiency and performance

[10] ITIL was formally an acronym for Information Technology Infrastructure Library (ITIL), but today, it is so widely known that its name stands alone -- ITIL is an approach to manage IT as a quality service which includes a detailed set of practices for IT strategy, design, implementation, operation, and continual improvement

Exhibit XIII – 1
NiSource Corporate Services Company
Information Technology Function Organization
As of December 31, 2019



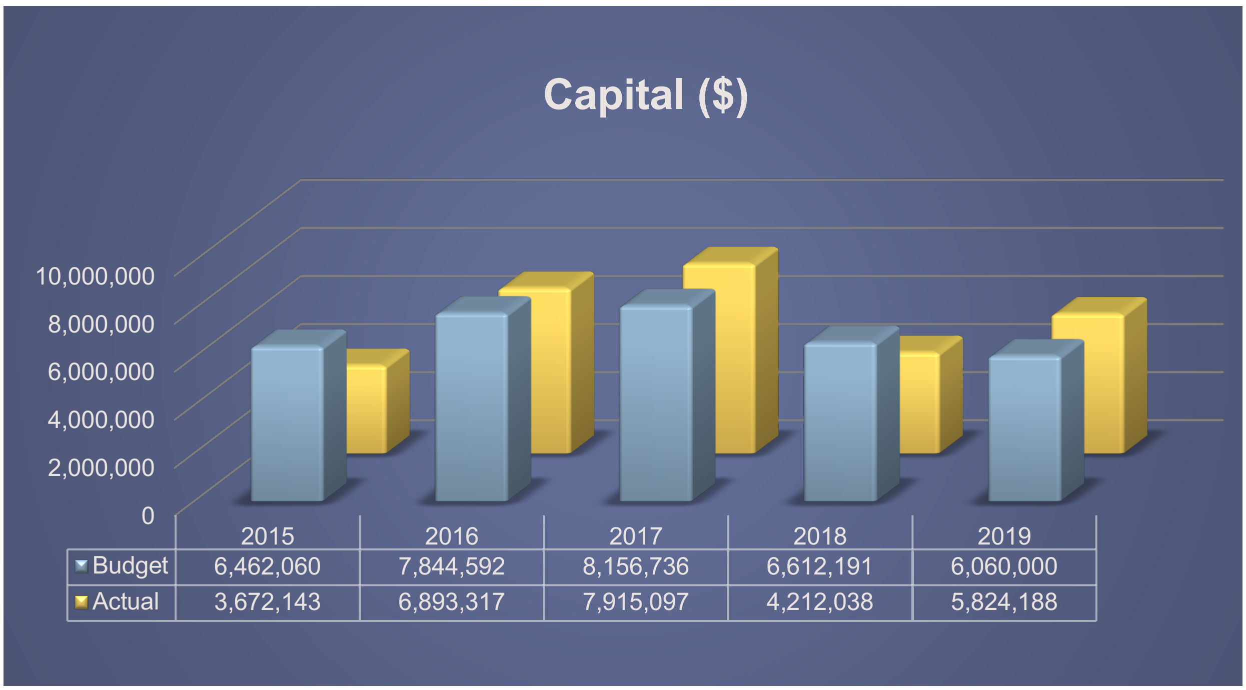
Source: Data Request EM-2

NCSC retains third-party vendors to provide certain IT services for itself and NiSource Inc. subsidiaries. The servicing agreements in place provide NCSC with added industry expertise in network solutions and security, application support, cloud computing, and other specialty IT services. In order to track third-party vendor performance, NCSC tracks and monitors data based on service level agreements (SLA). The SLAs were reviewed to determine whether vendors are meeting critical key performance service levels; no areas of concern were noted.

CPA's IT capital and operating & maintenance (O&M) expenditures are displayed in Exhibit XIII – 2 and Exhibit XIII – 3, respectively. Capital spending ranged from $3.6

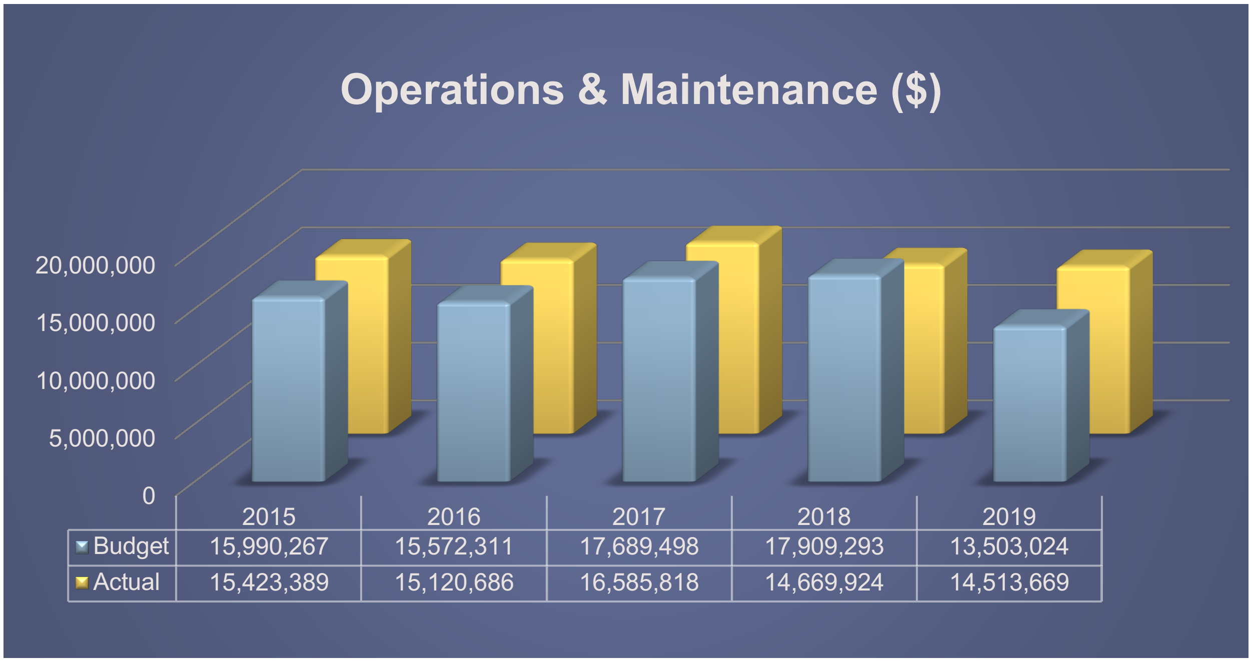
million in 2015 to over $7.9 million in 2017. Capital expenditures at CPA increased during this period as a result of initiatives/major projects related to acquisition and installation of hardware upgrades (i.e., storage and network security devices), implementation of new workplace technologies, and enhancement of network resiliency-connectivity throughout NiSource Inc.'s service territories. O&M expenditures at CPA remained relatively constant ranging from $14.5 million to $16.5 million with NCSC continually focusing on boosting cyber security and customizing applications and processes to enhance operational effectiveness.

Exhibit XIII – 2
Columbia Gas of Pennsylvania, Inc.
Budget vs. Actual IT Capital Expenses
For the Years 2015-2019



Source: Data Request IT-14-UR

Exhibit XIII – 3
Columbia Gas of Pennsylvania, Inc.
Budget vs. Actual IT O&M Expenses
For the Years 2015-2019



Source: Data Request IT-13-UR

To optimize business system functionalities, existing systems need to be constantly updated and/or upgraded by implementing the newest technologies on the market. NCSC, in their efforts to enhance and ensure to meet designated goals, has various projects underway to modernize equipment and streamline IT processes, conduct annual IT/cyber security audits, and routinely provide employees with cyber awareness training sessions and materials. Due to the sensitive nature, projects and audit results were provided to and reviewed by the auditors but are not disclosed in this audit report.

Findings and Conclusions

Our examination of NCSC's IT functional area included a review of the organizational structure, staffing levels, operational expenses, policies and procedures, cyber security measures, employee IT training techniques, and all relative information. Based on our review of NCSC's IT efforts, no evidence came to our attention that would lead the auditors to conclude that areas reviewed were not being adequately addressed.

Recommendations

None

XIV. ACKNOWLEDGEMENTS

We wish to express our appreciation for the cooperation and assistance provided by the officers and staff of NiSource Inc. and Columbia Gas of Pennsylvania, Inc. during this management and operations audit.

This audit was conducted by Craig Bilecki, Susannah Ellis, Tim Kerestes, Melissa Lawrence, and Eric McKeever of the Management Audit Division of the Pennsylvania Public Utility Commission's Bureau of Audits.

COLUMBIA GAS OF PENNSYLVANIA, INC.

XV. APPENDICES

Appendix A	Columbia Gas of Pennsylvania, Inc. Financial and Operating Data and Statistics
Appendix B	Columbia Gas of Pennsylvania, Inc. Balance Sheet

COLUMBIA GAS OF PENNSYLVANIA, INC.
Financial and Operating Data Statistics

DATA AND STATISTICS	2014	2015	2016	2017	2018	Compound Growth
OPERATING REVENUE ($)						
Residential	$ 391,795,217	$ 390,596,326	$ 354,816,554	$ 405,633,902	$ 431,600,845	2.4%
Commercial	133,940,116	127,151,296	103,417,438	119,219,845	133,057,714	-0.2%
Industrial	18,690,702	18,555,013	19,472,139	21,861,523	21,339,437	3.4%
Other	18,884,182	(90,235)	16,223,723	15,895,866	4,243,172	-31.2%
Total Operating Revenue	**$ 563,310,217**	**$ 536,212,400**	**$ 493,929,854**	**$ 562,611,136**	**$ 590,241,168**	**1.2%**
OPERATION & MAINTENANCE (O&M) EXPENSES ($)						
Natural Gas Well Head Purch., Interco. Trans.	$ 499,324	$ 361,982	$ 289,178	$ 355,444	$ 331,646	-9.7%
Natural Gas Transmission Line Purchases	234,329,337	144,569,926	123,764,115	147,434,092	172,861,109	-7.3%
Natural Gas City Gate Purchases	23,939,598	19,119,721	19,501,602	16,957,628	16,116,479	-9.4%
Other Gas Purchases	321,543	18,597,823	(28,840,972)	11,610,373	(5,137,150)	NM
Exchange Gas	(9,418,996)	(5,852,243)	2,976,346	(3,537,610)	(409,735)	-54.3%
Purchased Gas Expenses	830,733	993,940	1,081,088	1,049,829	1,035,295	5.7%
Gas Withdrawn from Storage	95,943,432	79,055,271	70,365,403	60,973,237	67,912,133	-8.3%
Gas Delivered to Storage - Credit	(104,967,991)	(61,790,197)	(49,721,730)	(65,408,668)	(65,198,955)	-11.2%
Gas Used for Other Utility Operations - Credit	(437,466)	(409,498)	(303,982)	(349,622)	(396,970)	-2.4%
Other Gas Supply Expenses	450	-	4,500	112,917	-	-100.0%
Total Gas Supply Operation Expenses	**$ 241,039,964**	**$ 194,646,725**	**$ 139,115,548**	**$ 169,197,620**	**$ 187,113,852**	**-6.1%**
Wells Expense	$ 2,514	$ 6,332	$ -	$ -	$ -	-100.0%
Lines Expense	9,563	8,317	-	-	-	-100.0%
Compressor Station Expense	380,296	111,473	1,521	-	-	-100.0%
Measuring and Regulating Station Expenses	7,065	4,103	-	131,501	196,275	129.6%
Purification Expenses	6,502	116	-	-	-	-100.0%
Gas Losses	3,791	2,746	2,097	2,173	2,175	-13.0%
Storage Well Royalties	5,976	5,938	5,976	5,923	5,536	-1.9%
Maintenance of Reservoirs and Wells	10,156	2,392	-	-	-	-100.0%
Maintenance of Compressor Station Equipment	9,867	2,703	-	-	-	-100.0%
Maintenance of Purification Equipment	9,945	4,346	-	-	-	-100.0%
Total Underground Storage Expenses	**$ 445,675**	**$ 148,466**	**$ 9,594**	**$ 139,597**	**$ 203,986**	**-17.7%**
Operation Supervision and Engineering	$ 8,410,561	$ 7,074,600	$ 7,067,113	$ 8,109,005	$ 7,237,215	-3.7%
Distribution Load Dispatching	243,746	175,072	195,915	136,192	205,387	-4.2%
Mains and Services Expenses	13,535,406	14,809,864	16,063,879	19,612,813	20,505,011	10.9%
Measuring and Reg. Station Expenses - General	549,549	428,440	512,954	534,046	561,103	0.5%
Measuring and Reg. Station Expenses - Ind.	251,228	246,251	256,785	270,899	296,539	4.2%
Meter and House Regulator Expenses	2,226,991	2,290,513	2,235,158	2,332,342	2,369,105	1.6%
Customer Installations Expenses	5,035,798	5,347,879	5,179,882	6,582,009	5,891,238	4.0%
Other Expenses	6,441,880	5,892,486	5,912,730	4,529,731	4,127,117	-10.5%
Rents	292,843	247,772	141,285	138,152	184,435	-10.9%
Maintenance Supervision and Engineering	77,485	58,300	58,176	135,915	145,251	17.0%
Maintenance of Structures and Improvements	32,968	151,086	182,868	184,080	98,780	31.6%
Maintenance of Mains	14,297,036	13,975,686	12,337,892	12,618,465	11,665,601	-5.0%
Maint. of Measuring & Reg. Station Equip. - Gen.	461,860	989,349	859,828	905,608	737,064	12.4%
Maint. of Measuring & Reg. Station Equip. - Ind.	165,890	158,211	202,008	131,414	264,099	12.3%
Maintenance of Services	1,875,312	4,230,481	6,407,530	7,727,089	4,190,866	22.3%
Maintenance of Meters & House Regulators	228,543	244,656	339,012	607,123	468,032	19.6%
Maintenance of Other Equipment	944,190	945,342	925,204	887,933	1,012,714	1.8%
Total Distribution O&M Expenses	**$ 55,071,286**	**$ 57,265,988**	**$ 58,878,219**	**$ 65,442,816**	**$ 59,959,557**	**2.1%**
Meter Reading Expenses	$ 771,839	$ 723,097	$ 706,276	$ 723,848	$ 727,886	-1.5%
Customer Records & Collection Expenses	8,692,027	9,121,990	8,563,764	7,624,218	8,382,921	-0.9%
Uncollectable Accounts	22,744,883	22,531,036	18,408,558	22,287,473	30,054,587	7.2%
Misc. Customer Accounts Expenses	24,518	22,504	17,554	14,142	17,656	-7.9%
Total Customer Account Operations Expenses	**$ 32,233,267**	**$ 32,398,627**	**$ 27,696,152**	**$ 30,649,681**	**$ 39,183,050**	**5.0%**
Customer Assistance Expenses	$ 9,068,673	$ 10,697,406	$ 6,615,431	$ 6,305,899	$ 8,818,428	-0.7%
Inform. & Instructional Advertising Expenses	123,041	227,459	204,801	191,919	130,334	1.4%
Misc. Customer Service & Inform. Expenses	964,400	772,898	898,412	1,075,664	1,141,053	4.3%
Total Cust. Ser. & Inform. Operations Exp	**$ 10,156,114**	**$ 11,697,763**	**$ 7,718,644**	**$ 7,573,482**	**$ 10,089,815**	**-0.2%**

NM = Not Meaningful
Source: Annual Reports to the Pennsylvania Public Utility Commission (2014 through 2018)

COLUMBIA GAS OF PENNSYLVANIA, INC.
Financial and Operating Data Statistics

DATA AND STATISTICS	2014	2015	2016	2017	2018	Compound Growth
O&M EXPENSES (continued) ($)						
Demonstrating and Selling Expenses	$ 631,141	$ 534,849	$ 514,073	$ 899,995	$ 765,349	4.9%
Advertising Expenses	7,032	35,528	81,290	349,356	186,462	126.9%
Total Operation Sales Expenses	**$ 638,173**	**$ 570,377**	**$ 595,363**	**$ 1,249,351**	**$ 951,811**	**10.5%**
Administrative and General Salaries	$ 4,130,932	$ 13,051,009	$ 21,112,050	$ 24,432,367	$ 19,793,323	48.0%
Office Supplies and Expenses	1,919,601	2,578,502	4,983,517	6,243,155	4,119,524	21.0%
Outside Service Employed	41,483,698	28,055,102	22,812,626	28,113,534	25,700,157	-11.3%
Property Insurance	177,694	142,879	71,452	51,883	53,261	-26.0%
Injuries and Damages	2,922,223	3,322,268	3,608,989	3,647,185	3,587,060	5.3%
Employee Pensions and Benefits	5,229,119	9,111,912	9,970,177	20,326,100	2,697,594	-15.3%
Regulatory Commission Expenses	1,815,064	2,160,919	2,170,560	2,037,807	2,623,298	9.6%
General Advertising Expenses	202,122	287,324	440,119	437,975	216,097	1.7%
Miscellaneous General Expenses	354,199	490,009	533,551	631,961	589,902	13.6%
Rents	644,943	3,104,723	4,818,954	5,583,242	5,392,249	70.0%
Maintenance of General Plant	194,264	1,209,430	2,283,175	2,631,374	3,672,623	108.5%
Total Admin. and General O&M Expenses	**$ 59,073,859**	**$ 63,514,077**	**$ 72,805,170**	**$ 94,136,583**	**$ 68,445,088**	**3.7%**
Total Gas O&M Expenses	**$ 398,658,338**	**$ 360,242,023**	**$ 306,818,690**	**$ 368,389,130**	**$ 365,947,159**	**-2.1%**
RECEIPTS BY VOLUME (MCF)						
Purchased Gas	41,436,351	37,253,031	32,241,112	33,779,946	41,596,725	0.1%
Gas of Others Received for Transportation	46,821,214	39,150,906	42,151,486	41,976,834	44,666,611	-1.2%
Exchange Gas Received	9,997,897	36,882,396	6,094,464	8,719,979	12,984,066	6.8%
Gas from Storage	21,794,563	18,498,963	22,809,968	21,402,438	22,778,777	1.1%
Total Receipts	**120,050,025**	**131,785,296**	**103,297,030**	**105,879,197**	**122,026,179**	**0.4%**
DELIVERIES BY VOLUME (MCF)						
Residential	36,166,954	33,009,592	29,625,172	29,857,741	35,354,098	-0.6%
Commercial	23,869,842	22,661,998	21,062,831	21,587,248	24,490,235	0.6%
Industrial	22,064,233	16,671,983	22,785,777	22,758,837	23,432,505	1.5%
Other	(182,067)	(803,269)	1,321,081	659,226	1,122,707	NM
Total Sales	**81,918,962**	**71,540,304**	**74,794,861**	**74,863,052**	**84,399,545**	**0.7%**
Injected into Storage	22,728,764	21,949,481	19,362,933	21,121,775	23,045,943	0.3%
Interdepartmental Sales						NM
Exchange Gas	10,312,601	37,369,021	6,339,428	10,038,455	13,638,770	7.2%
Off-system Sales	3,569,740	1,786,326	2,132,066	2,252,094	2,127,606	-12.1%
Gas Used by Company	86,397	80,107	93,355	78,584	90,376	1.1%
Other Deliveries	**36,697,502**	**61,184,935**	**27,927,782**	**33,490,908**	**38,902,695**	**1.5%**
Total Deliveries (Sales & Other Deliveries)	**118,616,464**	**132,725,239**	**102,722,643**	**108,353,960**	**123,302,240**	**1.0%**
UNACCOUNTED FOR GAS (MCF)						
Total Receipts	120,050,025	131,785,296	103,297,030	105,879,197	122,026,179	0.4%
Less: Total Deliveries	118,616,464	132,725,239	102,722,643	108,353,960	123,302,240	1.0%
Unaccounted For Gas	1,433,561	(939,943)	574,387	(2,474,763)	(1,276,061)	NM
UFG AS A % OF TOTAL RECEIPTS						
Unaccounted For Gas	1,433,561	(939,943)	574,387	(2,474,763)	(1,276,061)	NM
Total Receipts	120,050,025	131,785,296	103,297,030	105,879,197	122,026,179	0.4%
% Unaccounted For Gas	1.2%	-0.7%	0.6%	-2.3%	-1.0%	NM
AVERAGE CUSTOMERS						
Residential	382,981	384,924	387,223	390,590	394,027	0.7%
Commercial	37,189	37,166	37,128	37,193	37,228	0.0%
Industrial	280	273	270	265	263	-1.6%
Other						NM
Totals	**420,450**	**422,363**	**424,621**	**428,048**	**431,518**	**0.7%**
AVERAGE EMPLOYEES						
Totals	**564**	**609**	**640**	**654**	**668**	**4.3%**
GAS LINES						
Field Lines (M. Ft.)	39,574	39,670	39,992	40,170	40,647	0.7%
Field Lines (Miles)	7,495	7,513	7,574	7,608	7,698	0.7%
Services	420,733	422,052	425,038	429,532	433,187	0.7%

NM = Not Meaningful
Source: Annual Reports to the Pennsylvania Public Utility Commission (2014 through 2018)

COLUMBIA GAS OF PENNSYLVANIA, INC.
Balance Sheet

BALANCE SHEET	2014	2015	2016	2017	2018	Compound Growth
UTILITY PLANT ($)						
Utility Plant	$ 1,602,769,848	$ 1,802,547,518	$ 2,014,638,685	$ 2,260,819,037	$ 2,470,802,933	11.4%
Construction Work in Progress	15,335,088	20,600,883	20,719,517	25,509,347	47,472,392	32.6%
TOTAL UTILITY PLANT	**1,618,104,936**	**1,823,148,401**	**2,035,358,202**	**2,286,328,384**	**2,518,275,325**	**11.7%**
Accum. Depreciation and Amortization	(347,678,816)	(372,792,110)	(401,188,111)	(430,976,763)	(463,846,359)	7.5%
NET UTILITY PLANT	**$ 1,270,426,120**	**$ 1,450,356,291**	**$ 1,634,170,091**	**$ 1,855,351,621**	**$ 2,054,428,966**	**12.8%**
OTHER PROPERTY & INVESTMENTS ($)						
Nonutility Property	$ 8,346	$ 8,346	$ 8,346	$ 8,346	$ 8,346	0.0%
Accum. Depreciation and Amortization						NM
Investments in Associated Companies	18,198,819	18,747,420	19,212,454	19,552,267	19,968,120	2.3%
Investment in Subsidiary Companies						NM
Noncurrent Portion of Allowances						NM
Other Investments						NM
Special Funds	6,800,785	6,951,631	5,379,904	8,129,791	634,282	-44.7%
TOTAL OTHER PROPERTY & INVESTMENTS	**$ 25,007,950**	**$ 25,707,397**	**$ 24,600,704**	**$ 27,690,404**	**$ 20,610,748**	**-4.7%**
CURRENT & ACCRUED ASSETS ($)						
Cash	$ 2,619,993	$ 2,007,675	$ 3,066,604	$ 3,234,594	$ 3,928,067	10.7%
Special Deposits						NM
Working Fund	2,550	2,550	2,550	2,550	2,550	0.0%
Temporary Cash Investments	1,329,880					-100.0%
Notes Receivable						NM
Customer Accounts Receivable						NM
Other Accounts Receivable	-	-	-	253,000	253,205	6993.6%
Accum. for Uncollectible Accounts						NM
Notes Receivable from Assoc. Companies	49,451,445	32,093,843	51,653,849	52,210,954	44,704,353	-2.5%
Accts Receivable from Assoc. Companies	133,033	165,777	200,310	170,365	153,584	3.7%
Fuel Stock						NM
Fuel Stock Expenses Undistributed						NM
Plant Materials and Operating Supplies	657,437	750,307	749,078	902,238	1,040,237	12.2%
Merchandise						NM
Other Materials and Supplies						NM
Allowances						NM
Gas Stored Underground-Current	96,517,312	79,249,492	58,603,722	63,036,980	60,321,627	-11.1%
Liquefied Gas Stored and Held for Proc.						NM
Prepayments	2,757,557	2,871,891	2,773,274	2,751,040	4,717,579	14.4%
Advances for Gas						NM
Interest and Dividends Receivable						NM
Rents Receivable						NM
Accrued Utility Revenues						NM
Miscellaneous Current and Accrued Assets	238,529	24,130	65,923	7,158	234,291	-0.4%
TOTAL CURRENT & ACCRUED ASSETS	**$ 153,707,736**	**$ 117,165,665**	**$ 117,115,310**	**$ 122,568,879**	**$ 115,355,493**	**-6.9%**
DEFERRED DEBITS ($)						
Unamortized Debt Expenses						NM
Unrecovered Plant and Regulatory Study	$ 2,175,021	$ (15,423,977)	$ 12,666,996	$ 150,696	$ 5,792,438	27.7%
Other Regulatory Assets	265,720,439	271,735,886	274,999,215	270,905,360	292,807,240	2.5%
Prelim. Survey and Investigation Charges	3,478,322	3,059,484	3,556,945	3,797,652	1,766,047	-15.6%
Temporary Facilities						NM
Misc. Deferred Debits	7,710,980	8,070,527	4,901,644	5,029,166	5,012,468	-10.2%
Def. Losses from Disposition of Plant						NM
Unamortized Loss on Reacquired Debt						NM
Accum. Deferred Income Taxes	65,891,765	67,356,767	87,864,056	73,139,609	130,360,758	18.6%
TOTAL DEFERRED DEBITS	**$344,976,527**	**$334,798,687**	**$383,988,856**	**$353,022,483**	**$435,738,951**	**6.0%**
TOTAL ASSETS & TOTAL DEBITS	**$1,794,118,333**	**$1,928,028,040**	**$2,159,874,961**	**$2,358,633,387**	**$2,626,134,158**	**10.0%**

NM = Not Meaningful
Source: Annual Reports to the Pennsylvania Public Utility Commission (2014 through 2018) and Auditor Analysis

COLUMBIA GAS OF PENNSYLVANIA, INC.
Balance Sheet

BALANCE SHEET	2014	2015	2016	2017	2018	Compound Growth
PROPRIETARY CAPITAL ($)						
Common Stock Issued	$ 45,127,800	$ 45,127,800	$ 45,127,800	$ 45,127,800	$ 45,127,800	0.0%
Preferred Stock Issued						NM
Capital Stock Subscribed						NM
Stock Liability for Conversion						NM
Premium on Capital Stock						NM
Gain on Required Capital Stock						NM
Other Paid-in Capital Stock	7,720,355	7,889,827	7,889,827	7,889,827	52,889,827	61.8%
Discount on Capital Stock						NM
Capital Stock Expense						NM
Retained Earnings						NM
Unappropriated Undistributed Earnings	485,681,501	549,929,309	616,758,450	682,583,017	788,379,728	12.9%
Reacquired Capital Stock						NM
Other						NM
TOTAL PROPRIETARY CAPITAL	**$ 538,529,656**	**$ 602,946,936**	**$ 669,776,077**	**$ 735,600,644**	**$ 886,397,355**	**13.3%**
LONG-TERM DEBT ($)						
Bonds						NM
Reacquired Bonds						NM
Advances from Associated Companies	$ 394,040,000	$ 495,515,000	$ 540,515,000	$ 625,515,000	$ 705,515,000	15.7%
Other Long-Term Debt						NM
Unamortized Premium on Long-Term Debt						NM
Unamortized Discount on Long-Term Debt						NM
TOTAL LONG TERM DEBT	**$ 394,040,000**	**$ 495,515,000**	**$ 540,515,000**	**$ 625,515,000**	**$ 705,515,000**	**15.7%**
OTHER NONCURRENT LIABILITIES ($)						
Obligations Under Capital Leases-Noncurrent	$ 9,270,325	$ 31,653,678	$ 30,966,820	$ 29,971,206	$ 28,879,266	32.9%
Accum. Provision for Property Insurance						NM
Accum. Provision for Injuries and Damages	104,659	131,188	91,750	131,519	113,922	NM
Accum. Provision for Pensions and Benefits	13,201,508	20,002,464	20,955,289	2,243,278	6,164,096	-17.3%
Accum. Misc. Operating Provisions	1,193,508	1,395,926				-100.0%
Accum. Provision for Rate Refunds						NM
Long-Term Portion - Instrument Liabilities						NM
TOTAL NONCURRENT LIABILITIES	**$ 23,770,000**	**$ 53,183,256**	**$ 52,013,859**	**$ 32,346,003**	**$ 35,157,284**	**10.3%**
CURRENT & ACCRUED LIABILITIES ($)						
Notes Payable						NM
Accounts Payable	$ 26,345,164	$ 27,818,195	$ 33,370,866	$ 37,788,421	$ 51,512,287	18.3%
Notes Payable to Associated Companies	47,350,000	18,525,000				NM
Account Payable to Associated Companies	103,716,356	42,454,001	122,402,577	160,735,432	85,227,081	-4.8%
Customer Deposits	3,370,025	3,369,187	3,130,590	3,008,011	3,341,169	-0.2%
Taxes Accrued	7,773,679	(838,024)	(415,340)	645,927	17,076,472	21.7%
Interest Accrued	370,472	322,895	317,561	313,924	320,693	-3.5%
Dividends Declared						NM
Matured Long-Term Debt						NM
Matured Interests						NM
Tax Collections Payable	422,173	62,115	463,695	487,773	501,507	4.4%
Misc. Current and Accrued Liabilities	68,683,905	66,427,283	65,624,790	58,562,693	60,809,351	-3.0%
Obligations Under Capital Leases-Current	181,710	802,182	868,290	992,133	1,088,458	56.4%
TOTAL CURRENT & ACCRUED LIABILITIES	**$ 258,213,484**	**$ 158,942,834**	**$ 225,763,029**	**$ 262,534,314**	**$ 219,877,018**	**-3.9%**
DEFERRED CREDITS ($)						
Customer Advances for Construction	$ 7,862,150	$ 8,163,421	$ 4,901,549	$ 5,019,190	$ 4,954,204	-10.9%
Accum. Deferred Investments Tax Credits	3,182,584	2,822,344	2,462,104	2,130,553	1,829,330	-12.9%
Def. Gains from Disposition of Utility Plant						NM
Other Deferred Credits	9,981,342	10,520,567	7,881,641	8,543,871	5,734,277	-12.9%
Other Regulatory Liabilities	52,312,649	46,193,356	41,758,883	324,250,547	267,658,578	50.4%
Unamortized Gain on Reacquired Debt						NM
Accum. Deferred Income Taxes	506,226,468	549,740,326	614,802,819	362,693,265	499,011,112	-0.4%
TOTAL DEFERRED CREDITS	**$ 579,565,193**	**$ 617,440,014**	**$ 671,806,996**	**$ 702,637,426**	**$ 779,187,501**	**7.7%**
TOTAL LIABILITIES & OTHER CREDITS	**$1,794,118,333**	**$1,928,028,040**	**$2,159,874,961**	**$2,358,633,387**	**$2,626,134,158**	**10.0%**

NM = Not Meaningful
Source: Annual Reports to the Pennsylvania Public Utility Commission (2014 through 2018) and Auditor Analysis

Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
www.puc.pa.gov

Direct Testimoney 1

Columbia Gas of Pennsylvania, Inc.
2021 General Rate Case
Docket No. R-2021-3024296

Requested Annual Rate Increase of $98,300,000

Submitted by Richard C. Culbertson on June 16, 2021

1430 Bower Hill Road

Pittsburgh, PA 15243

Richard.c.culbertson@Gmail.com

609-410-0108

Introduction

After hearing sworn public testimony today. I believe it best to provide written testimony.

My written testimony reiterates my formal complaint.

I, Richard C Culbertson, as an asset management expert[1], an expert at writing international ASTM and ISO Asset Management consensus standards[23], property owner of several (4 units) properties of which at times I am a customer and who is responsible for the financial wellbeing and security of those who

[1] Per U.S Government Accountability Office report. https://www.gao.gov/assets/gao-19-57.pdf Table 3: Names and Affiliations of Experts Interviewed (Page 49): Mike Aimone, P.E., Former Director of DoD; Admiral Thad W. Allen (ret.) Former Commandant of the U.S. Coast Guard; Kerry A. Brown Professor of Employment and Industry – Australia; Richard Culbertson …

[2]The United States is a signatory of the World Trade Agreement (Uruguay Accords) https://www.wto.org/english/docs_e/legal_e/17-tbt_e.htm This agreement requires -- Participation in technical expert groups (standard setters) shall be restricted to persons of professional standing and experience in the field in question. In the U.S. there are two organizations ASTM E53 Asset Management (I chair this 195-member committee) and ISO Technical Committee 251 – Asset Management (I am membership secretary).

[3]Example -- Primary author of ASTM E2279 … Guiding Principles of Property Asset Management this international standard is required to be used by U.S. Department of Defense in DODI 5000.64. , https://www.esd.whs.mil/Portals/54/Documents/DD/issuances/dodi/500064p.pdf?ver=2019-06-10-100933-460

reside in those properties, hereby submit this testimony to the Pennsylvania Public Utility Commission to reject, in full, this proposed rate increase is not in the public interest after due consideration of all the elements of the public interest. Gas public utilities are infrastructure companies – and are all about various forms of asset management. Furthermore, the proposed and existing rates are unjust, unreasonable, and therefore unlawful. The result of the rate case must reject the proposed rate increase because of the lack of required internal controls (operations, reporting, and compliance) and reliable audits provide assurance that Columbia Gas is fulfilling its obligations as a public utility and as part of NiSource, a publicly traded corporation. Existing rates must be reduced to where they are not unlawful, and operations improved to the extent of which Columbia operates in the public interest. The public, customers, governments and private property owners must be made whole. Any criminal acts by Columbia or their parent company must be referred to the appropriate law enforcement authorities. Recognize customers and property owners have rights under the Unfair Trade Practices and Consumer Protection Law, 73 P.S. Sections 201-1 to 201-9.3. [4] [5]

Current Condition and Needs

This rate case presents a **crisis of trust** – that can Columbia Gas and the Commission deliver on just and reasonable rates.

[4] https://www.attorneygeneral.gov/wp-content/uploads/2018/02/Unfair_Trade_Practices_Consumer_Protection_Law.pdf

[5] It must be noted this law has been recently by the Pennsylvania strengthened by the Pennsylvania Supreme Court in *Gregg v. Ameriprise Financial, Inc.*

"[T]he Commission would not and should not allow a rate base to be ***inflated by bookkeeping which had improperly capitalized expenses."*** [6][7] (Hope Paragraph 82. 1944) This is exactly what has been done by Columbia Gas.

I have major concerns there is not sufficient judicial independence in the decision-making of Judge Hoyer. Whatever happens with Judge Hoyer presiding in the rate case, the results will not be universally accepted as having the appearance of impartial and independent justice. There will always be an appearance of some sort of undue influence. Why not Administrative Law Judge Dunderdale presiding in the is rate case? For the same reasons, Judge Hoyer should not be presiding in this case.

I recognize Judge Hoyer is not independent from my complaint of May 8, 2017, against Columbia Gas of Pennsylvania of which he presided and of which the PUC still has not dispositioned. He is not independent from acting as a protector and an employee of the Pennsylvania Public Utility Commission. He is not independent as a supervisor and – protector of Judge Dunderdale, who recommended on December 4, 2020, that Columbia's previous rate increase be denied in its entirety.

> Judge Dunderdale's Recommended Decision December 4, 2020. R-2020-3018835 PA PUC ET AL V COLUMBIA GAS OF PA INC RD.PDF
>
> *VII. ORDER* (PAGE 409)
>
> ***THEREFORE,***
>
> ***IT IS RECOMMENDED:***
>
> 1. ***That Columbia Gas of Pennsylvania, Inc. shall not place into effect the rates, rules, and regulations contained in Supplement No. 307 to Tariff Gas-Pa. P.U.C. No. 9, the same having been found to be unjust, unreasonable, and therefore unlawful.***

This recommended order was preceded by her explanatory Introduction:

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[6] FEDERAL POWER COMMISSION et al. v. HOPE NATURAL GAS CO. CITY OF CLEVELAND v. SAME Decided Jan. 3, 1944 https://www.law.cornell.edu/supremecourt/text/320/591

[7] I have placed in many places in this document words in bold, underlined or highlighted, these were added for emphasis and better understanding of the reader.

"This base rate decision recommends the Commission deny the request of Columbia Gas Company of Pennsylvania, Inc. in its ***entirety because it has not met its burden of proving, by substantial evidence, that the proposed base rate revenue increase will result in just and reasonable rates,*** *as required by 66 Pa.C.S.A. § 1301 during the current Coronavirus-2019 pandemic.* (It is understood that 66 Pa.C.S.A. § 1301 does not include *"during the current Coronavirus-2019 pandemic."* But is a major consideration to deny the rate increase.)

JOINT STATEMENT OF CHAIRMAN GLADYS BROWN DUTRIEUILLE &

VICE CHAIRMAN DAVID W. SWEET https://www.puc.pa.gov/pcdocs/1693872.pdf

Date: February 18, 2021

"As part of this fully litigated proceeding … We support the staff recommendation before us today to reduce Columbia's annual revenue increase from $100,437,420 to $63,548,905, thereby resulting in savings to challenged ratepayers.

Finally, while the Commission's action today substantially reduces the impact of Columbia's rate increase…"

The process and thoughts by which the PUC arrived at and provided an annual rate increase of $63,548,905 is troubling.

It is important to recognize the Judge Dunderdale has been a PUC Administrative Law Judge longer than any of the Commissioners of the PUC. When an experienced judge identifies acts or things done or omitted to be done as unlawful, others that were not a party to the rate case (staff) should have taken extreme caution in recommending to the Commission to overturn an impartial, experienced, competent, and diligent administrative law judge.

The $63,548,905, was awarded on a *"notional vote"*. Notional votes of the Commission are not open. Yet the PUC issued a press release that *"State regulators approve smaller than requested rate increase for Columbia Gas of Pa."* BRIAN C. RITTMEYER | Friday, Feb. 19, 2021, 5:37 p.m. [8] I

Title 66 § 319. Code of ethics.[9]

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8 https://triblive.com/local/regional/state-regulators-approve-smaller-than-requested-rate-increase-for-columbia-gas-of-pa/

9 https://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66

*(a) General rule. --**Each commissioner and each administrative law judge** __shall__ conform to the following code of ethics for the Public Utility Commission. A **commissioner and an administrative law judge** __**must**:__*

(1) Avoid __impropriety and the appearance of impropriety__ in all activities.

*(2) __Perform all duties__ __impartially__ and __**diligently.**__*

*(c) Removal of judge for violation. --__Any administrative law judge who violates the provisions of subsection (a)__ **shall be removed from office…***

The PUC acts as a quasi-court. In Pennsylvania per the Pennsylvania Constitution, Pennsylvania Courts are open.

§ 11. Courts to be open;

***All courts shall be open**; and every man for an injury done him in his lands, goods, person, or reputation* [tangible and intangible property] *shall have remedy by due course of law,* [due process] *and right and __justice administered without__ sale, denial or __delay.__*

Was there a due process breach?

The **staff** did not preside over this rate case. **They are not presiding officers**, presiding officers are limited to the Commission and the Administrative Law Judges.

There is a concept in FASB Concept 8 things should be what thery are purported to be. The PUC should not provide to the public a decision until there is a decision.

OPINION AND ORDER

3018835 OPINION AND ORDER - 3018835-OSA - EXCEPTIONS TO RECOMMENDED DECISION - COLUMBIA GAS OF PA - (NOTATIONAL VOTE)

https://www.puc.pa.gov/pcdocs/1693880.docx

February 19, 2021

I Background

… Columbia's testimony provided that its requested increase in annual operating revenues was driven by two main contributing factors: (1) its continued ***investment in its accelerated pipeline replacement program and (2) the Company's increased expenses on a variety of safety initiatives, including repairs to be undertaken on customer-owned pipes.***

D. Disposition (Page 42) … we shall decline to adopt the ALJ's recommendation to completely deny Columbia's requested rate relief due to the pandemic, for the following two reasons: (1) in our opinion, the ***continued use of traditional ratemaking methodologies*** *during this pandemic is consistent with the setting of just and reasonable rates and the constitutional standards established in* ***Bluefield and Hope Natural Gas****, and the pandemic does not change the continued application of these standards; and (2) there is a lack of substantial evidence in this record to support the ALJ's recommendation to completely deny the Company's requested rate increase….*

There is nothing in Pennsylvania's law or regulations regarding *"Traditional Ratemaking".* **If this is traditional ratemaking, this is unlawful ratemaking.**

The Commission's Order is not within the letter and spirit of Bluefield and Hope rulings. Granted, some portions of the Hope[10] and Bluefield decisions apply in ratemaking today. In the Hope case:

- Accounting was not reliable as a basis for ratemaking (Foot Note 40 in part)
    - *"To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science."*

[10] FEDERAL POWER COMMISSION et al. v. HOPE NATURAL GAS CO. CITY OF CLEVELAND v. SAME Decided Jan. 3, 1944 https://www.law.cornell.edu/supremecourt/text/320/591

- The opinions in 1944 were valid in 1944. Certain laws, regulations, and standards have changed --- Generally Accepted Accounting Principles, the Federal Government's Cost Principles, and auditing requirement have significantly changed.

- *'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12.*
- *Paragraph 12 – [T]he Commission was not bound to the **use of any single formula or combination of formulae in determining rates**. Its rate-making function, moreover, **involves the making of 'pragmatic adjustments.'** … And when the Commission's order is challenged in the courts, **the question is whether that order 'viewed in its entirety'** meets the requirements of the Act.*

That means to be viewed in its entiritey, there must not be unreasonable impediments for evidence and discovery to be freely entered into the record. I believe from past experience Columbia tries minimize discovery and is not forthcoming. Corporations do not have Fifth Amendment privileges. Discover has the more privilidges in a rate case than independent auditor engaged to review the books and records of a public company. Public auditors have some numerical materiality threshold. Mischarging , waste, fraud and abuse of customers do not have that same threshold. To customers abuse and small amounts are qualifiability material information.

> ***** *It is not theory but the impact of the rate order which counts*.** *If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged.* ***It is the product of expert judgment which carries a presumption of***

validity. *And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is* ***invalid because it is <u>unjust and unreasonable</u> in its <u>consequences.</u>***

I too have expert judgment – on areas of internal controls – and waste, fraud, abuse and mismanagement.   I lead in the writing and vetting international asset management standard. I provided detailed comments to the GAO Yellow Book – first on behalf of the Aerospace Industries Associaton and secondly for Asset Leadership Network. I gave for example a joint presentation along with the lead editor of the document at the National Acadimies of Sciences a couple years ago.

- *Paragraph 25 The Federal Power Commission was given broad powers of regulation. The fixing of 'just and reasonable' rates (§ 4) with the powers attendant thereto* 20 *was the heart of the new regulatory system.*
    - *20 <u>The</u>* ***<u>power to investigate</u>*** *<u>and ascertain the</u>* ***<u>'actual legitimate cost'</u>*** *<u>of property</u> (§ 6), the requirement <u>as to books and records</u> (§ 8), control over rates of depreciation (§ 9), the requirements for <u>periodic and special reports</u> (§ 10),* ***the broad powers of investigation*** *(§ 14) are among the chief powers supporting the rate making function.*

The Commission or the staff did not recognize fundamentals in *Hope* and related law – rates are based upon **<u>property owned by the utility</u>** <u>and investments must be prudent or necessary under the responsibilities and commitments of the utility.</u>

<u>15 U.S.C.</u>A. § 717e Ascertainment of cost of property (a)Cost of property

The Commission may ***investigate*** *and ascertain the* ***<u>actual legitimate cost of the property</u>*** *of every natural-gas company, the depreciation therein, and, when* ***found necessary for rate-making purposes****, <u>other facts which bear on the determination</u> of such cost or depreciation and the fair value of such property.*

What are and are not *"actual legitimate cost"* are now, defined in laws and regulations, as opposed to in the 1930s or 1940s, but the actual legitimate cost now and then would exclude costs not necessary and imprudent, such as **accelerated replacements** and paying for the property and maintenance that is the responsibility of other's … by law and tariff. We see **manifestations of unreasonable cost** and cost that are not actual legitimate costs in a table generated from Columbia's parent company later in this document.

Ratemaking requires due process and due diligence (and other requirements placed upon judges in their oaths) to reach just and reasonable rates and charges. **It does not appear the Commission sufficiently uses either of these.** I, as an expert, property owner, and an interested party do not want that to happen in this rate case.

Again from the PA PUC -- *D. Disposition (Page 42) … we shall decline to adopt the ALJ's recommendation to completely deny Columbia's requested rate relief due to the pandemic, for the following two reasons: (1) in our opinion, the **continued use of traditional ratemaking methodologies** during this pandemic is consistent with the setting of just and reasonable rates and the constitutional standards established in **Bluefield and Hope Natural Gas**, and the pandemic does not change the continued application of these standards…*

The problem with the above assertion of the requirement of the Supreme Court Case of FEDERAL POWER COMMISSION et al. v. HOPE NATURAL GAS CO and CITY OF CLEVELAND v. SAME is that the **Commission's assertion is not consistent with what the Supreme Court decided on December 3, 1944, in Hope.**

Supreme Court Decision (Douglas, J.) held it is ***"the result reached and not the method employed"*** which is controlling in determining *"just and reasonable"* rates. Hope, 320 U.S. 13

*"The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, **involves*** **(Meaning part of the process, not the primary objective or primary work.)** *a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that **'regulation does not insure that the business shall produce net revenues.'** 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the **investor or company point of view** it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. … 176. By that standard the return to the equity owner **should** be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, **should** be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. **For we are of the view** that the end result in this case **cannot** be condemned under the Act as unjust and unreasonable **from the investor or company viewpoint."*** **(Then who's point of view can determine what is unjust and unreasonable? --- the customers,** (as I did in my testimony on July 8, 2020, on Columbia's previous rate case) **and the Commission.)**

In Hope, the Supreme Court did not reject *"general economic conditions"* as an element to arrive at just and reasonable rates (paragraphs 15 and 16). But, asserted ***"the result reached and not the method employed"*** which is controlling in determining *"just and reasonable"* rates. Increasing rates during the Covid Pandemic, as judge Dunderdale did, certainly can be a consideration in a rate case based upon the opinion of Justice Douglas. **It is not the process but the just and reasonable outcome under the circumstances.**

*Paragraph 54 [T]he Commission's rate ORDERs **must** be founded on **due consideration of all the elements of the public interest** which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act if that Act be applied as an entirety. See, for instance, §§ 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. §§ 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. §§ 717c(a—d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. **But its very foundation is the 'public interest',** and the **public interest is a texture of multiple strands**. It includes **more than contemporary investors** and contemporary consumers. The needs to be served are not restricted to immediacy, **and social as well as economic costs must be counted.***

Paragraph 54 is the heart of Hope.

Good due process and due diligence should have been sorted out independently among the ALJ, staff, and the Commission. As result customers and communities have been harmed. **There was not a common understanding of the 1944 Hope decision within the PUC.**

PUC or staff shifted the burden of proof from the utility**,** who did not submit proof that their proposed rate increase was just and reasonable, to the Administrative Law Judge – nonexistent or unsubmitted evidence is not evidence. The substantial evidence that Columbia's rates were not just and reasonable was included in my sworn public input testimony that was admitted into evidence in Judge Dunderdale's Third Interim Order. Unreasonable and unjust conditions were exposed to the Columbian Gas in July 2016 when they abandoned my private property (customer's service line), when I submitted a complaint regarding numerous abuses to the PUC May 2017, sworn testimony Columbia rate case August 2018, and sworn testimony in Columbia's Rate case in July 2020. Largely the issues identified early on remain uncorrected today as will be shown in this complaint. Public testimony today by Mr. Hicks repeats some of my experience with Columbia Gas on my properties on McFarland Road and Espy Avenue in Dormont.

Hope does provide in paragraph –*10 ORDER Reducing Rates. Congress has provided in § 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission* ***'SHALL be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.'*** *Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by ORDER. Sec. 5(a) also empowers the Commission to ORDER a '**decrease where existing rates are unjust** * * * **unlawful, or are not the lowest reasonable rates.'** And Congress has provided in § 19(b) that on review of these rate ORDERs the 'finding of the Commission as to the facts, if supported by substantial evidence, SHALL be conclusive.'* ***Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the details of the general prescription 8 of § 4(a) and § 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.***

The stated omissions of the Congress and state government in 1944 are not true today. Portions of Hope is not and was not **intended to be absolute**. Hope is a time capsule addressing rate case conditions of Jan. 3, 1944. What is *"actual legitimate cost of the property"* has been clearly defined in now existing laws and regulations.

What are reasonable costs, for example, have also been defined in Government regulations – of which the PUC and Columbia are subject, such as for recipients of Federal grants *2 CFR § 200.404 Reasonable costs.* ***§ 200.404 Reasonable costs.***

*"A cost is reasonable if, in its nature and amount, it does not exceed that which would be incurred by a **prudent person** under the circumstances prevailing at the time the decision was made to incur the cost.*

--- ***consideration must be given to:***

*(a) Whether the cost is of a type generally recognized as **ordinary and necessary** for the operation of the non-Federal entity or the **proper and efficient performance** of the Federal award.*

(b) The restraints or requirements imposed by such factors as: sound business practices; arm's-length bargaining; Federal, state, … other laws and regulations; and terms and conditions of the Federal award.

*(c) **Market prices for comparable goods or services for the geographic area."***

For comparable market prices of gas service for the geographic area surrounding Pennsylvania, NiSource provides the Columbia Gas of Pennsylvania (rate base/ rate) is outside of the generally acceptable competitive range[11] – thus **unreasonable**. The Federal Government in placing this regulation on recipients of grant money requires that grant money must be spent reasonably. The rate base and rates of Columbia Gas of Pennsylvania **are unreasonable for the geographic area** for rate making purposes. Furthermore prudent person in the conduct of competitive business would not spend money unnecessarily nor give away free product or service … **then expect other customers to "foot the bill".**

The Pennsylvania Public Utilities Commission provides us their Mission Statement.

Our Mission

[11] See Federal Acquisition Regulation (FAR) *15.306 Exchanges with offerors after receipt of proposals.* In competitive arrangements – submissions of proposal outside to the competitive range are not considered because the supplier's cost or price is considered unreasonable. *FAR 31.201-3 Determining reasonableness. (a) **A cost is reasonable if**, in its nature and amount, it **does not exceed** that which would be incurred **by a prudent person in the conduct of competitive business.***

> *"The mission of the Pennsylvania Public Utility Commission is to balance the needs of consumers and utilities; ensure safe and reliable utility service at reasonable rates; protect the public interest; educate consumers to make independent and informed utility choices; further economic development; and foster new technologies and competitive markets in an environmentally sound manner."*

*"ORDERs must be founded on **due consideration** of **all the elements of the public interest**. (Hope).* **"Due considerations"** does not mean "balance". For "protect the public interest" – protect is defense. In Hope, the considerations of public interest are active-- ***But its (rates) very foundation is the 'public interest',*** *and the* ***public interest is a texture of multiple strands****. It* ***includes more than contemporary investors and contemporary consumers.*** *The needs to be served are not restricted to immediacy,* ***and social as well as economic costs must be counted.***

This PUC Mission Statement strays from the Pennsylvania Public Utility law. The phrases in words and spirit do not include ***"balance the need"*** in any form. The first priority is **not** serving the needs or wants of a monopolistic public utility but to comply with the Pennsylvania Public Utility law under Title 66 https://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66 starting with Chapter 5. Powers and Duties.

As a mission statement, the second priority should be the first priority *"ensure safe and reliable utility service at reasonable rates".* The first priority of the Commission is PA Title 66 *§ 501. General powers -- is* ***duty to enforce****; the second is* ***exercise administrative authority and supervise public utilities****; and the third priority* ***is directed to utilities -- Compliance*** *-- Every public utility, its officers, agents, and employees,* ***shall observe, obey, and comply****….*

The first priority of Columbia Gas should also be *"safe and reliable utility service at reasonable rates"*. This is what the Commission promises, and the public expects.

<u>The basis of rates</u>

By word and deed Columbia and to some extent the Commission stray from the overall meaning of the Hope decision. They take the position rates are in lockstep with spending – we spend on capital projects and you pay for what we spend, and we get a good profit as a percentage of what we have spent.

Profits come from spending.

<u>That approach is wrong</u>, the <u>incentive for the utility is spending</u>, not on the performance of safe and reliable service.

The Hope decision makes that clear – the objective of the Commission and Columbia is not to make a good profit for Columbia but to serve the **public interest.**

Pennsylvania Law provides for the Commission: *Title 66 § 523.* ***Performance factor consideration. (1986)***

(a) *Considerations. --**The commission <u>shall</u> consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility <u>when determining just and reasonable rates</u> under this title.** On the basis of the commission's consideration of <u>such evidence</u>, it shall give effect to this section by making such adjustments to specific components of the utility's claimed cost of service <u>as it may determine to be proper and appropriate</u>. Any adjustment made under this section shall be made on the basis of **<u>specific findings</u>** <u>upon evidence of record</u>, which **findings** shall be set forth explicitly, together with their underlying rationale, in the final order of the commission.*

The problem is the Commission does not investigate through Generall Accepted Government Audits – if you do not look you do not find.

Here the requirement is based upon performance and to do that, performance criteria must be established (Now we call them elsewhere *"Key Performance Indicators (KPIs)".* It does not appear that the Commission has set these KPI at are used consistently. Under good oversight, these KPIs would be audited with independent audits. The GAO Yellow Book addresses performance audits. Columbia and the Commission do not use the requirements and guidance in the GAO Yellow Book.

So, the Commission and Columbia rely on *"traditional"* ratemaking, which gravitates to a *"cost plus percentage of cost"* understanding and arrangement. The incentive in this type of arrangement is to spend money on capital projects, which establishes the rate base. The table provided below of which data was provided from facts of the parent company NiSource, shows the product of such an approach.

The **Cost-Plus Percentage of Cost contract or arrangement is illegal in Government contracting** – it is also not allowed in 2 CFR 200 under Federal Grant requirements

The Uniform Rules' Cost or Price Analysis Standards – 2 C.F.R. § 200.324.[12] *d)* ***The cost plus a percentage of cost and percentage of construction cost*** *methods of contracting* ***must not be used****. (Footnote 14) (Emphasis added. These contracting methods must never be used.)*

Footnote 14"[13] *These types of contracts are strictly prohibited. They are prohibited because there is no incentive for the contractor to keep its incurred costs low due to the associated percentage of profit earned on incurred costs. There is instead a reverse incentive for the contractor to continue to increase its incurred costs in order to increase its associated profit. In other words, the higher its incurred costs, the higher the contractor's profit will be.*

[12] https://www.law.cornell.edu/cfr/text/2/200.324

[13] PRICING GUIDE FOR RECIPIENTS AND SUBRECIPIENTS UNDER THE UNIFORM RULES (2 C.F.R. PT. 200) PFLD-FISCAL PDAT FEMA OFFICE OF CHIEF COUNSEL., Footnote page 8.

Columbia's rates do not *"further economic development"* they impede economic development and grossly harm those most who cannot afford unreasonable rates.

We heard that today from Mr Hicks' in his sworn testimony today.

Nature of Complaints.

66Pa.C.S. 701. Complaints.

*The commission, or **any person**, … **having an interest in the subject matter**, … may complain in writing, setting forth any act or thing done or omitted to be done by any public utility in violation, or claimed violation, of any law which the commission has jurisdiction to administer, or of any regulation or order of the commission. Any public utility, or other person, or corporation likewise may complain of any regulation or order of the commission, which the complainant is or has been required by the commission to observe or carry into effect.*

52 Pa. Code § 59.13. Complaints.

*(a) Investigations. Each **public utility shall make a full and prompt investigation of complaints made to it or through the Commission by its customers.***

Types of Violations:

Internal Controls – **(A)** effective and efficient operations, **(B)** Reliable Reporting, and **(C)** Compliance with law, regulations, standards, tariff, and internal policy. The PA PUC and NiSource/ Columbia Gas of Pennsylvania are subject to the internal control standards—GAO Green Book and the COSO Integrated Internal Control Framework (2013) (As asserted by management in the **NiSource SEC 10-K**) and

Management Directive of the Governor's Office -- Standards for Internal Controls in Commonwealth

Agencies 325.12 Amended (2018).

"PA Energy Consumer Bill of Rights"
https://www.puc.state.pa.us/general/consumer_ed/pdf/Consumer_Bill_Of_Rights.pdf

(A) Safe and reliable utility service
(B) Providing the utility with access to its equipment -- ***their meter*** **(only)**.
(C) Competitive energy marketplace.
(D) To receive the benefits of new services, technological advances, improved efficiency, and ***competitive prices****.*
(E) The ***right to be protected from unfair, deceptive, fraudulent, and anti-competitive practices of providers*** *… natural gas service.*
(F) Expectation of quality, reliability, and maintenance of your … natural gas distribution service… ***monitored by the PUC.***
(G) ***Unbiased, accurate and understandable information****…*

Facts provided from NiSource, Parent of Columbia Gas

https://investors.nisource.com/company-information/default.aspx

COMPANY FACTS

Columbia Gas of Kentucky
- ✓ Second Largest Gas-Only local distribution company (LDC) in KY (-137K Customers)
- ✓ - 2,600 Miles of Pipe
- ✓ - 350 Miles of Bare Steel & Cast Iron
- ✓ - $327M Rate Base

Columbia Gas of Maryland
- ✓ Complementary to PA Operations (-34K Customers in MD)
- ✓ - 660 Miles of Pipe
- ✓ - 50 Miles of Bare Steel & Cast Iron
- ✓ - $149M Rate Base

Columbia Gas of Ohio
- ✓ Largest LDC in Ohio (-1.5M customers)
- ✓ - 20,200 Miles of Pipe
- ✓ - 2,000 Miles of Bare Steel & Cast Iron
- ✓ - $3.2B Rate Base

Columbia Gas of Pennsylvania
- ✓ Third Largest LDC in PA (-436K Customers)
- ✓ - 7,700 Miles of Pipe
- ✓ - 1,200 Miles of Bare Steel & Cast Iron
- ✓ - $1.9B Rate Base

Columbia Gas of Virginia
- ✓ Third Largest LDC in VA (-274K Customers)
- ✓ - 5,300 Miles of Pipe
- ✓ - 140 Miles of Bare Steel
- ✓ - $850M Rate Base

~~**Indiana Electric (NIPSCO)**~~
- ~~✓ Third Largest Electric Utility in Indiana (-475K Customers)~~
- ~~✓ 2,850 MW of Environmentally Compliant Generation~~
- ~~✓ [illegible]0,000 Distribution Line Miles -3,000 Transmission Line Miles~~
- ✓ - $4.7B Rate Base

Indiana Gas (NIPSCO)
- ✓ Largest LDC in Indiana (-840K Customers)
- ✓ - 17,500 Miles of Pipe
- ✓ - 23 Miles of Bare Steel & Wrought Iron
- ✓ - $1.7B Rate Base

The NiSource Facts – when normalized in a table it provides a rate base per customer. *(2 CFR § 200.404 - Reasonable costs.* (The numbers are probably real from the records of the NiSource and Columbia.)

A cost is reasonable if, in its nature and amount, it does not exceed that which would be incurred by a prudent person *under the circumstances prevailing at the time the decision was made to incur the cost.*

… ***consideration must be given to***: *(c) Market prices for comparable goods or* ***services for the geographic area.***

The rate base per customer is not reasonable for the services in the geographic area. The facts from NiSource, the parent company of Columbia Gas of Pennsylvania show the **product of past practices.**

Columbia Gas of Pennsylvania should not be rewarded for not having effective internal controls that result in waste, fraud, and abuse. **This chart alone is justification not to grant this rate increase for Columbia Gas of Pennsylvania.** This chart alone should prompt the **Commission to order an external independent performance, forensic and financial audit of Columbia Gas of Pennsylvania, which I am requesting.**

It is in the public interest to find out why the rate base and rates are so much higher in Pennsylvania than in NIPSCO (Indiana), Ohio, and Kentucky and this is what I am requesting from the Commission.

This chart alone provides sufficient substantial evidence that Columbia Gas of Pennsylvania's rate or charges are not just and reasonable and must be declared unlawful as required under 15 U.S.C. COMMERCE AND TRADE § 717c - Rates and charges and PA Title 66 § 1301. Rates to be just and reasonable.

This one table of substantial evidence to not raise rates, outweighs Columbia's 10 volume submission of why the rate should be increased.

	~ No. of Customers (In 000)	Miles of Pipe	Calculated Miles of pipe per customer	Miles of Bare Steel and Cast Iron	Rate Base ($ 000,000)	Calculated Rate Base Per Customer $	
NIPSCO	840	17500	.020	23*	1700	***2024**	
COH	1500	20200	.013	2000	3200	2133	
CKY	137	2600	.019	2600	327	2387	
CVA	274	5300	.019	140**	850	3102	
CMD	34	660	.018	50	149	4382	
SUB TOL	2785				6226	2236	Ave
CPA	433	7700	.018	1200	2400	**** 5545**	
	3548				8626		

** CPA data was updated from information included in the Administrative Law Judge's Recommended Decision on December 4, 2020, Rate Case - R-2020-3018835. (Rate base $2,401,427,019 and ~433,000 customers -- ~ $5,545 per customer. This can be construed to be a hidden liability for each customer and their share of the rate base. The cost of money is substantial for each ratepayer. This high rate base per customer makes Columbia non-competitive in the energy marketplace.)

The rate base per customer is 2.7 times more in Pennsylvania than Indiana and 2.6 for Ohio. This is prima facie evidence that the **rate base is unreasonable thus rates are unreasonable**. The law of the land is that rates and charges must be just and reasonable otherwise they are unlawful.

$5,545 is the proportional share of hidden debt each customer has for gas piping. Doing the math --If CPA had been operating as efficiently as NIPSCO (Indiana), CPA's rate base could be **~$1,524,593,000 less**.

The figures are not adjusted for the *"stub service"*[14] [15][16]of which CPA provides (the service line excludes customer's service line) – meaning the only utility property on private property is the meter assembly. A new customer's service line has an estimated cost of $2,000.

We heard today Mr. Hicks testify he had estimates of $6000…when his service was discontinued.

The variance of rate base per customer for CPA in comparison to neighboring sister companies of NiSource makes Columbia Gas of Pennsylvania's financials and operations suspect. For prudent auditors, investors, and the Commission, **this should present suspicions and red flags of waste, fraud, and abuse and mismanagement.** Customers have a right to assurance that Columbia has adequate internal controls and that rates are just and reasonable and are not unlawful.

From the facts provided by CPA's parent – it is apparent that CPA has performed unnecessary and not reasonable work.

I recommend the Administrative Law Judge **focus the rate case solely on this evidence** in and about the chart and declare and **deny this rate increase request in its entirety**.

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[14] *18 CFR Part 201 - UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT* https://www.law.cornell.edu/cfr/text/18/part-201

[15] *Account 380 Services. A. This account shall include the cost installed of service pipes and accessories leading to the customers' premises. B. A complete service begins with the connection on the main and extends to but does not include the connection with the customer's meter. A* ***stub service*** *extends from the main to the property line, or the curb stop.*

It is not in the public interest to stay on the path to further abuse ratepayers.

The case is made in this complaint – now Columbia must prove by substantial evidence that the information of which they and their parent provided to the Commission and the public is wrong and should not be considered in this rate case.

For further investigation by Columbia and the Commission, understanding, appropriate action in this rate case or otherwise, I also provide.

Itemized general and specific complaints:

From the format provided in 66Pa.C.S. 701. Complaints.		
Act or thing done or omitted to be done by Columbia:	**Violation, or claimed violation, of any law, which the commission has jurisdiction to administer, or of any regulation or order of the commission;** **Expectation to investigate;**	**Comments:** The Commission has jurisdiction over natural gas service consistent with the boundaries of responsibility of the utility and the Commission. Columbia has the responsibility to maintain reliable internal controls

	<u>Counter with the expected burden of proof from Columbia.</u>	
Columbia includes in their rate base costs that are not ***"actual legitimate cost"***, are not necessary, and are unreasonable.	To be considered as part of the rate base and rates it must have **entered** <u>legally</u> ***"into the consideration".*** *U.S. Reports: Bluefield Co. v. Pub. Serv. Comm., 262 U.S. 679 (1923)* ***15 USC Ch. 15B: NATURAL GAS §717e. Ascertainment of cost of property … "actual legitimate cost"*** *"<u>All costs which a public utility uses to compute its base rate,</u> including improvements to infrastructure and to safety, <u>are relevant</u> in a base rate proceeding. In addition, <u>safety</u>*	Determining what are *"actual legitimate cost"* requires, knowledge, expertise, competence, due process, and due diligence for accounting, operations and ratemaking purposes. Self-assertion is not sufficient – reasonable assurance of internal controls are required. This occurs through using the Integrated Internal Control Framework and reliable audits.

	specifically is always a relevant issue in a base rate proceeding."[17]	
Columbia has not fulfilled its obligations for effective integrated internal controls.	Title 66 § 501. General powers. (c) **Compliance**. Every public utility, its officers, agents, and employees, and every other person or corporation subject to the provisions of this part, affected by or subject to any regulations or orders of the commission or of any court, made, issued, or entered under the provisions of this part, **shall observe, obey, and comply** with such regulations or orders, and the terms and conditions thereof. Chapter 8 of the U.S. Sentencing Commission SENTENCING OF	The overall framework for a compliant organization is not in place. This law applies to all Federal and Pennsylvania applicable laws, regulations, and standards.

[17] PA PUC Rate Case, Docket R-2020-3018835 ALJ Judge Dunderdale Third Interim Order December 4, 2020

	ORGANIZATIONS [18]applies as appropriate.	
Columbia does not have effective integrated internal controls and audits to assure unreasonable costs do not get into the rate base, as the parent NiSource claims in their SEC 10-K reports.[19]	The Commission expects the same high standards of accounting as other Government agencies. *PA Title 66 § 1351. Definitions. "Capitalized cost." Costs permitted to be capitalized pursuant to the Uniform System of Accounts and Generally Accepted Accounting Principles.* *15 U.S. Code § 78m - Periodical and other reports (This law (Securities and Exchange Act of 1934, is placed upon Columbia*	Accounting standards must not be violated for investor reporting purposes or ratemaking purposes. Internal controls are to prevent and detect wrong reporting based upon the COSO Integrated Internal Control Framework and the GAO Green Book – the major control elements: effective and efficient operations, reliable reporting, compliance with laws, regulations, standards, contracts… and protection of assets.

[18] UNITED STATES SENTENCING COMMISSION CHAPTER EIGHT - SENTENCING OF ORGANIZATIONS https://www.ussc.gov/guidelines/2018-guidelines-manual/2018-chapter-8

[19] For the fiscal year ended December 31, 2020 https://d18rn0p25nwr6d.cloudfront.net/CIK-0001111711/9f4ccf64-7861-4b15-936d-32aaaadeafa7.pdf (Page 118)
*"Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations **[COSO]** of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting."* Note - the integrated framework includes operations and compliance along with reporting.

	as part of publicly traded corporation.) *(2) Every issuer … **<u>shall</u>**—* *(A)make and keep books, records, and accounts, which, in reasonable detail, <u>accurately and fairly</u> reflect the <u>transactions and dispositions</u> of the **assets of the issuer;*** *(B)devise and maintain a system of <u>**internal** accounting **controls**</u> sufficient to provide **reasonable assurances** that—* *(i)transactions are executed in accordance with management's general or specific authorization;* *(ii)transactions are recorded as necessary (I) to permit preparation of financial **statements in conformity with generally accepted accounting** principles or any other criteria applicable to such statements,*	

	and (II) to maintain accountability for assets; (iii)access to assets is permitted only in accordance with management's general or specific authorization; and (iv)the recorded accountability for assets is compared with the existing assets at reasonable intervals and appropriate action is taken with respect to any differences; and (4) No criminal liability shall be imposed for failing to comply with the requirements of paragraph (2) of this subsection except as provided in paragraph (5) of this subsection. (5) ***No person shall knowingly circumvent or knowingly fail to implement a system of internal accounting controls or knowingly falsify any book,***	

	***record, or account described in paragraph** (2).*	
Columbia's costs under the **accelerated** pipeline replacement program **are not actual legitimate costs** because these costs were **not necessary.** Unnecessary costs are unallowable costs for reporting, ratemaking, and recovery purposes. Columbia claims these unnecessary costs as if they were necessary. The regulations nor the tariff contract have changed to make the unnecessary -- necessary. A tariff is a bilateral contract.	*Columbia's Tariff (**Contract**): 8.4 Ownership and Maintenance* *The Company **shall** own, maintain and renew, **when necessary**, its main extension and/or service line from its main to the point of delivery, as defined in Rule 7.1.* *7.1 Point of Delivery* *The point of delivery of gas to a customer shall be at the outlet side of the curb valve, or the property or lot line if there is no curb valve, at which point title of the gas shall pass to the customer; …* *PUC's representations to Customers:*	Truncating the economic life of "suitable for use assets" and replacing them with other assets is squandering value (waste), resulting in unreasonable cost. Unreasonable cost is unallowable for accounting, recovery, and reporting purposes. This practice unreasonably increases the rate base and consumer's rates without corresponding substantial benefits. The utility is required to maintain adequate, efficient, and safe service and facilities. What Columbia does is referred to as *"so-*

At a minimum, this is a breach of contract. Ramifications could include violations of the Federal False Claims Act.[20]	***Right to Safe and Reliable Utility Service[21] (service stops upon delivery)*** *The Pennsylvania Public Utility Code **requires** that **every public utility to create ensure and maintain adequate, efficient, safe, reliable and reasonable service. and maintain adequate, efficient, safe and reasonable service and facilities**. Utilities also are required to **make necessary repairs** and improvements to service and **facilities**.*	*called **'Averch-Johnson Effect'**—or more crudely, "gold plating."*[22] The table above from NiSource clearly shows the Columbia has succumbed to the "Averch-Johnson Effect". Columbia's work is sometimes more than adequate, not efficient, and not necessary work.

[20] 31 U.S. Code § 3729 - False claims https://www.law.cornell.edu/uscode/text/31/3729

[21] PA Energy Consumer Bill of Rights https://www.puc.pa.gov/general/consumer_ed/pdf/Consumer_Bill_Of_Rights.pdf

[22] A Guide To Utility Ratemaking page 156 https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf

Columbia is not following Pennsylvania law regarding what is charged to capitalized costs that go into the rate base. Placing cost of other's property -- customer's service lines, as if utility-owned these are unlawful. Columbia has been charging cost customer's service lines to Uniform System of Accounts, Account 376.08 Mains- CSL Replacements. CSL is Customer Service Line Replacements.	*PA Title 66 "Rate base." The value of the whole or any part of the **property of a public utility** which is used and useful in the **public service**.* *§ 1501. Character of service and facilities.* *Every **public utility shall** furnish and maintain **adequate, efficient, safe, and reasonable service and facilities**, and shall make all such repairs, changes, alterations, substitutions, extensions, and **improvements** in or to such service and facilities as **shall be necessary** or proper for the accommodation,*	It is recognized the Commission approved the practice of replaced customer's service lines to be charged to the 376 Mains account in 2008.[24] It was wrong then and it is wrong now. The Commission is not empowered to issue illegal orders counter to PA title 66, GAAP, and the Uniform System of Accounts. Columbia puts themselves at risk when they knowingly follow illegal orders. The saying – *"be careful what you ask for"* is good advice. Regardless, Columbia is solely responsible for what it does.

[24] Docket No. P-00072337, Public Meeting held May 1, 2008. IT IS ORDERED: 1. That the Columbia Gas of Pennsylvania Inc. petition for limited waivers of tariff rules 4.7, 4.8, 4.9, 4.10, 4.13, 5.3, 8.1(a), and 8.4 related to customer service line replacement is approved. The waiver only applies to the Tariff, not to Federal and Pennsylvania law and regulations. It does not appear the tariff was modified to reflect this side deal.

Account 376 Mains and Account 380 Services do not provide for the inclusion of non-utility property. Account 380 specifically excludes customer's service lines with the recognition of "*stub service*".[23]	*convenience, and safety of its patrons, employees, and the public.* *§ 1510. Ownership and maintenance of natural and artificial gas service lines.* *When connecting the premises of the customer with the gas utility distribution mains, the public utility shall furnish, install and maintain the service line or connection according to the rules and regulations of the filed tariff.* ***A public utility shall not be authorized or required to acquire or assume ownership of any customer's service line.*** (That means any portions or component of a customer's	The jurisdiction of the Commission does not include expanding nor reducing the property rights and obligations of private property owners per U.S. (14th Amendment) and PA (Article I § 1.) Constitutions. A customer's service line is real property of a property owner and is included in deeds as appurtenances. **2 CFR § 200.404 - Reasonable costs.** A cost is reasonable if, in its nature and amount, it does not exceed that which would be incurred by a prudent person under the circumstances prevailing at the time the decision was made to incur the cost. … **consideration must** be given to:

[23] https://www.law.cornell.edu/cfr/text/18/part-201 Includes -- *Items 1. Curb valves and curb boxes. 2. Excavation, including shoring, bracing, bridging, pumping, backfill, and disposal of excess excavated material. 3. Landscaping, including lawns, and shrubbery. 4. Municipal inspection. 5. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.*

	service line including the riser).... ***<u>Maintenance of service lines shall be the responsibility of the owner of the service line.</u>***	(a) Whether the cost is of a type generally <u>recognized as</u> ordinary and **<u>necessary</u>** … or the proper and efficient performance … (c) **<u>Market prices</u>** for comparable goods or services **for the <u>geographic area</u>.** Account 380 Services. Does include -- 5. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks. For accounting purposes capital direct cost generally include cost to acquire and place an asset ready for use. In 380, appurtenances of a private property owner are specifically beyond a stub service and therefore outside of the jurisdiction

		of authority and control of the utility and the Commission. Placing cost of replacement and maintenance of Customer's service lines in Account 376 – Mains is also inappropriate and – frankly deceptive. Accounting concepts in FASB Concept 8[25] QC4. If financial information is to be **useful, it <u>must</u> be** relevant and <u>faithfully represent what it</u> **<u>purports to represent.</u>** The usefulness of financial information is enhanced if it is comparable, verifiable, timely, and understandable.
The current rate base and current rates and proposed	*<u>Hope Paragraph 6</u>* ***<u>'No greater injustice to consumers</u>*** *could be*	The US Government and Pennsylvania require the use of the

[25] Financial Accounting Standards Board (FASB) Statement of Financial Accounting Concepts No. 8, September 2010 https://www.fasb.org/cs/ContentServer?c=Document_C&pagename=FASB%2FDocument_C%2FDocumentPage&cid=1176171111614

rates have <u>not</u> been based upon *"**actual legitimate cost**".* Actual legitimate costs are based upon laws, regulations, standards, contracts, tariffs, and legal orders. Columbia has provided non-compliant financials.	*done than to allow items [such] as operating expenses and at a later date <u>include them in the rate base</u>, thereby placing multiple charges <u>upon the consumers</u>.' Id., 44 P.U.R.,N.S., at page 12.* Hope- Paragraph 12 – *[T]he Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' ... And when the Commission's order is challenged in the courts**, the question is whether that order 'viewed in its <u>entirety'</u> meets the requirements of the Act.*** **From Hope—Paragraph 54** *These elements are reflected in the Natural Gas Act, if that Act*	GAO Green Book (Internal Controls), GAO Yellow Book (Audits) and TITLE 2—Grants and Agreements PART 200—UNIFORM ADMINISTRATIVE REQUIREMENTS, COST PRINCIPLES, AND AUDIT REQUIREMENTS FOR FEDERAL AWARDS Management Directive of the Governor's Office -- Standards for Internal Controls in Commonwealth Agencies 325.12 Amended (2018) Management Directive of the Governor's Office -- Performance of Audit Responsibilities 325.3 Amended (2011) Reasonable assurances of *"**actual legitimate cost**"* **are only a starting place in ratemaking.**

	be applied as an entirety. See, for instance, §§ 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. §§ 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. §§ 717c(a—d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the ***'public interest',*** *and the public interest is* ***a texture of multiple strands****. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and* ***social*** *as well as* ***economic*** *costs* ***must*** *be counted.* *"The "principal purpose" of the Natural Gas Act is to encourage the orderly development of* ***plentiful supplies*** *of … natural*	We the participants, and ratepayers have no reasonable assurance that the rate base is comprised of *"**actual legitimate cost"*** – That is expected from Columbia before a rate case begins.

	*gas **at reasonable prices**."* NAACP v. FPC, 425 U.S. 662, 669-70 (1976).	Judge Dunderdale did consider the social and economic cost on ratepayers. Distribution cost and prices of natural gas services is no longer reasonable from Columbia Gas and does not fulfil the principle purpose of the National Gas Act.
Some costs as represented as owned are not owned by Columbia Gas.	*PA Title 66 "Rate base." The value of the whole or any part of the **<u>property of a public utility</u>** which is used and useful in the **public service**.* The current rate base and proposed additions to the rate base must be assets that are owned by Columbia Gas.	**<u>Customer's service lines nor portions thereof are neither owned nor used in public service.</u>** The rate base must only include actual legitimate costs. The rate base must be reduced accordingly.

Columbia Gas nor the Pennsylvania Public Utilities Commission's organization provide reasonable assurance to customers, property owners, governments, investors, and other decision-makers and stakeholders that performance and attestation audits have been performed in conformance with required internal controls and generally accepted audits.	***"PA Energy Consumer Bill of Rights"* (E) and (G).** **The audits performed by Columbia and the PUC are not consistent with high-quality audits standards. They provide the company, the Commission nor consumers no assurance of effective internal controls.**	Adjudicating increases in rates is not the time for non-professional auditors to provide assurance of effective internal controls – in operations, reporting, and compliance in a rate case. The PA PUC must fulfill its obligations under the ***"PA Energy Consumer Bill of Rights"*, and Federal and Pennsylvania laws and regulations.** **The public must have reasonable assurance that Columbia is performing to its obligations.**
General – material weaknesses in Columbia's internal audits. Columbia's auditors claim they conduct audits in conformance with … *"This audit conforms with the*	For example, terms to be used in audits that inform management, the Board of Directors, PUC supervisors and regulators, investors, governments, consumers, and other stakeholders for decision-making purposes include:	The Commission's auditors do not do a good job of this either as they do not use the GAO Yellow Book. The Commission's audit released in July 2020 used the terms weaknesses and deficiencies but not the proper complete terms.

International Standards for the Professional Practice of Internal Auditing." This organization sponsored COSO Integrated Internal Control Framework. An element of that is Compliance with Laws and Regulations. Columbia does not follow generally accepted audit practices – resulting in unreliable audits. After Sarbanes Oxley was passed a part of the was establishing the Public Company Accounting Oversite Board. (PCAOB) The PCAOB established a series of Audit Standards that are placed upon public accounting firms. Here in	*A2. A* ***control objective*** *provides a specific target against which to evaluate the effectiveness of controls. A control objective for internal control over financial reporting generally* <u>*relates to a relevant assertion*</u> *and states a criterion for evaluating whether the company's control procedures in a* ***specific area provide*** <u>***reasonable assurance***</u> *that a misstatement or omission in that relevant assertion is prevented or detected by controls on a timely basis.* *A7.* <u>***A material weakness***</u> *is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a* <u>*reasonable possibility that a material*</u>	This resulted in Columbia believing they had a good audit but for those who know what to look for in audits, this appeared to be a failed audit. The PUC audits are public documents and can be used for decision-making for investors. It is harmful when there is lacking use of proper standards, completeness, and misuse of terminology.

Audit Standard No.5 with Appendix A [26]are definitions that auditors are to use. <u>These terms above are not used correctly in the PUC and NiSource audits.</u> When not following the proper internal control framework and the required audit standards, material deficiencies, and significant weaknesses are missed, making those financial, operational and compliance audits unreliable.	<u>*misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis*</u>*.* *A11.* ***<u>A significant deficiency</u>*** *is a deficiency, or a combination of deficiencies, in internal control over financial reporting that is* <u>*less severe than a material weakness*</u>*, yet important enough to* <u>*merit attention by those responsible for oversight of the company's financial reporting (Board of Directors Audit Committee).*</u> *A3.* ***A deficiency*** *in internal control over financial reporting exists when the* ***design or operation*** *of a control does not*	

[26] PCAOB Auditing Standard No. 5, An Audit of Internal Control Over Financial Reporting that is Integrated with an Audit of Financial Statements and APPENDIX A – Definitions https://pcaobus.org/oversight/standards/archived-standards/pre-reorganized-auditing-standards-interpretations/details/Auditing_Standard_5_Appendix_A#:~:text=A%20material%20weakness%20is%20a,detected%20on%20a%20timely%20basis

	*allow management or employees, in the normal course of performing their assigned functions, to **prevent or detect** misstatements on a timely basis.* *A deficiency in design exists when (a) a control necessary to meet the control objective is missing or (b) an existing control is not properly designed so that, even if the control operates as designed, the control objective would not be met.* *A deficiency in operation exists when a properly designed control does not operate as designed, or when the person performing the control does not possess the necessary authority or competence to perform the control effectively.*	
NiSource uses the term Gas Standards instead of	The internationally and domestically agreed-upon	Recognized bodies are recognized in the U.S. by the National Institute

company policy as a means to deceive the public and themselves into believing that a Gas Standard is more than an internal company policy.	definition of standard is found in Annex 1 of the World Trade Agreement[27] *"Standard -- __Document approved by a__ __**recognized body**__, that provides, for common and repeated use, rules, guidelines or characteristics for products or related processes and production methods, ..."*	of Standards (NIST) and the American National Institute of Standardization (ANSI). NiSource is not one of them. NiSource does not issue standards. ISO and ASTM along with others identified in 49 CFR 192.7 ... documents are incorporated by reference [IBR] do. NiSource Gas Standards are not standards. If NiSource had adopted the International Management Systems Standard ISO 9000 Quality Management – one of the first findings would be that NiSource does not have control of its policies and procedures. The finding would start with NiSource Gas Standards are not standards they are merely internal policy and only apply

[27] URUGUAY ROUND AGREEMENT – WORLD TRADE ORGANIZATION (1986-94) https://www.wto.org/english/docs_e/legal_e/17-tbt_e.htm This was codified in the **`National Technology Transfer and Advancement Act of 1995'.** **https://www.nist.gov/standardsgov/national-technology-transfer-and-advancement-act-1995**

		internally. Internal policy must be consistent with Internal Controls under Compliance with Laws and Regulations.
A specific example of poor internal auditing: Starting with Audit Report 13 page 157 of 352 or 126 of 319 Columbia's Volume 4 of 10[28] Abandonment of Service Line Facilities. Unreasonable costs are charged to capital accounts because of weak internal controls. From the Executive Summary, *the review focused on the processes and controls in place to perform the following: …*	§ 1301. Rates to be just and reasonable. *a.Regulation.* ***--Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable****, and in* ***conformity with regulations…*** 52 Pa. Code § 59. - Abandonment of inactive service lines. (This regulation only applies to company owned service lines – Not customer's service lines.) In the PA Public Utility Code Title 66 section 102 that was published in	The GAO provides qualifications of an auditor. It is not good enough to go through the motions of an audit or bypass those qualifications. The purpose of audits is to prevent and detect waste, fraud, and abuse as well as to improve operations. Audits should provide reliable and material information for decision-making purposes.

[28] PUC Docket R-2021-3024296 Exhibit 13 Volume 4 of 10 PUC document 1698218

Execution of a service line abandonment ***in accordance with NiSource Gas Standards.*** Here the auditor gave a pass on the internal controls of NiSource Gas Standard 1740.010 Abandonment of Facilities. They also overlooked GS 1740.010(PA), which applies only to Pennsylvania. The PA Gas Standard Includes PA PUC regulation Chapter 59.36. Here, NiSource/ CPA just appended the Pennsylvania requirements on the back of the NiSource Gas Standard. The PA PUC regulation conflicts with the NiSource Gas Standard.	1984, service lines and customer's service line are defined. (These terms are not to be used interchangeably.) The Commission used the term "service line" correctly. Frequently Columbia does not.	The NiSource Gas Standards are not recognized standards – they are just internal policies. The term standard is used to be deceptive to those who do not understand standards. Internal policies never supersede laws, regulations, contract tariff and consensus standards. It is important for the reader to understand the difference between a performance standard and a

The Pennsylvania regulation takes a performance standard approach vs. a design approach of the NiSource internal policy; *"A review of the status of service lines that have had gas service discontinued **shall be made annually**, at periods not exceeding 15 months [To determined there is no prospect for reuse]. Lines which no longer qualify for retention shall be scheduled for abandonment as soon as practicable, but not later than 6 months after it has been determined there is no prospect for reuse.* (No prospect is-- no chance) The NiSource Gas Standard uses *"cannot be*		design standard. From the World Trade Agreement *2.8 Wherever appropriate, Members **shall specify technical regulations based on product requirements** in terms of **performance rather than design or descriptive characteristics**.* Also see Presidential Executive Order 13563 -- Improving Regulation and Regulatory Review Columbia in handling their own property has legal and fiduciary responsibility to safeguard their own assets and certainly legal and fiduciary responsibility to not to assume ownership and destroy another's property by illegal abandonment. "Cannot be determined" is different from "no prospect". As a

determined" instead of "*no prospect"* per reregulation. From experience, Columbia neither follows the NiSource Gas Standard, the PA version of the NiSource Gas standard nor the Pennsylvania PUC regulation. Annual reviews do not occur. Work orders for abandonment occur automatically from the NiSource computer system after 24 months. It issues a work order for an employee to remove the meter and another worker order is issued to destroy the service line – thereby		<u>result many service lines and customer's service lines are abandoned illegally resulting in substantial harm to property owners and rate payers.</u> Good audits would not have missed this. Audits that are designed to protect the company would. So what are we dealing with … deliberate – willful ignorance or condoning wrongdoing?

deenergizing the customer's service line as well. When property owner requests service they force the property owner to replace their customer's service line because Columbia took abandonment authority from the property owner by deception. The auditors overlooked in Pennsylvania; CPA has a *"stub"* service line, as defined in Account 380 Services. So when CPA does the wrongful abandonment, they abandon the stub service along with the customer's service line. The	CHAPTER 39 THEFT AND RELATED OFFENSES applies.[29]	In laws, trade agreements, and executive orders performance standards are preferred over design standards. For good reason Columbia unreasonably abandons service lines to the extent that service lines must be replaced within a year. The useful live of a service line is typically over fifty years. The auditors using a minimal one-year threshold hides the extent of the unreasonable improper abandonment 5495 service lines (excludes Indiana) X $10,000 = **$55 Million**. This

[29] https://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/18/00.039..HTM
""***Property***." *Anything of value, including real estate, tangible and intangible personal property, contract rights,*

customer's service line is not subject to the PUC regulation nor the PA PUC regulations. Columbia claims they have the authority to abandon both – they do not, and this is fraud. This is something of which the PUC is supposed to be protecting the public from in the PA Energy Consumer Bill of Rights. Appendix C of the audit report – New Service Line Install Subsequent to Abandonment. Here that audit show CPA had 563 abandoned service lines	*§ 3922. Theft by deception.* *(a) Offense defined. --A person is guilty of theft if he intentionally obtains or withholds property of another by deception. A person deceives if he intentionally:* *(1) creates or reinforces a false impression, including false impressions as to law, value, intention or other state of mind; but deception as to a person's intention to perform a promise shall not be inferred from the fact alone that he did not subsequently perform the promise;*	material information of the Audit Committee, the PUC and others -- as it over charges ratepayers. When internal wrongdoing is discovered by a company, the Sentencing Guidelines treat companies differently based upon how the company addresses and corrects the issues rather than hides the issues. The auditors should have been more sensitive in that NiSource is still under a Deferred Prosecution Agreement from poor/ illegal performance of Columbia Gas of Massachusetts September 13, 2018.

*"**Deprive.**" (1) To withhold property of another permanently … or with intent to restore only upon payment of reward or other compensation; or (2) to dispose of the property so as to make it unlikely that the owner will recover it."*
Abandonment is a form of disposition.

that had to be replaced within a year after their wrongful abandonment. The associated cost is unreasonable and – unallowable, about $5.6 Million (563 X $10,000). The theft by deception of customer's lines (563 X $2,000) is $1.1 and in Pennsylvania that is a felony.	*(2) prevents another from acquiring information which would affect his judgment of a transaction; or* *(3) fails to correct a false impression which the deceiver previously created or reinforced, or which the deceiver knows to be influencing another to whom he stands in a fiduciary or confidential relationship.*	The extent of lack of control of service line abandonment is a material weakness and should have been identified as such. This was qualitatively material information for NiSource management, CPA Management, Board of Directors external auditors and the PUC. Instead of informing management and the Board that they maybe involved in felony thefts and mischarging cost --- the message was the NiSource was not abandoning service lines on a timely basis.
Columbia Gas of Pennsylvania (A NiSource Company) Standards for Customer Service Lines,	The Plumbers Guide is used to defraud private property owners and private contractors who	It is not in the public interest for this utility to misrepresent the requirements of the U. S. Department of Transportation.

Meters, and Service Regulators [30] Also referred to as the **(Plumber's Guide).** This document asserts, misrepresents deceptively, Columbia's authority over private property owners, and their plumbing contractors. Columbia's service and authority stop at the property line upon delivery. Columbia only has access to its meter – the property of which it owns.	work for private property owners. PA CHAPTER 39 THEFT AND RELATED OFFENSES applies. § 3922. Theft by deception.	

[30] https://www.columbiagaspa.com/docs/librariesprovider14/contractors-and-plumbers/plumber-qualifications/plumber's-guide.pdf?sfvrsn=9

Columbia places higher requirements over workers on private property than their own workers on who work on Columbia's distribution system. This document is not an official Gas Standard, nor policy and has not been approved by an identified Company official. *Columbia requires **"The National Fuel Gas Code (ANSI Z223.1/NFPA 54) shall be followed."*** This is wrong based upon the Pennsylvania Uniform Construction Code and local Ordinances the	*PA Title 18 CHAPTER 49 FALSIFICATION AND INTIMIDATION 4912.*[32] *Impersonating a public servant.* *§ 4912. Impersonating a public servant.* *A **person commits a misdemeanor of the second degree** if he **falsely** **pretends to hold a position in the public service with intent to induce another to submit to such pretended official authority** or*	The fact this document has no company logo. It has a security classification of "PROPRIETARY". It is not attributed to a company official. It is not a NiSource Gas Standard and the fictitious form number at the bottom are all indications this may not be an officially approved company document. But Columbia officials claim they use this document every day and operationally they enforce it. **Red tagging without authority to red tag – this is the code official's job.**

[32] PA TITLE 18 CRIMES AND OFFENSES https://www.legis.state.pa.us/WU01/LI/LI/CT/PDF/18/18.PDF

International Gas Fuel Standards applies. Columbia misrepresents and defines themselves as: "<u>*Authority Having Jurisdiction*</u> *– Fire Chief, Local Code Official,* ***Representative of the Gas Company****, or others who are responsible for approving equipment, materials, installation, or procedures. Local codes, ordinances, and governmental regulations will govern when they are more stringent than the requirements contained herein. When in doubt as to the proper procedure, consult your Gas Company and* ***other authorities***	***otherwise to act in reliance upon that pretense to his prejudice.***	This document harmful to the integrity of the Commission. It is an illustration of what is wrong with NiSource and Columbia Gas of Pennsylvania. Most of all it harms ratepayers, property owners and plumbing professionals. **How can so many be so wrong for so long?** As an asset management expert the document is alarming – it shows this company is committed to wrongdoing rather than excellence. Columbia's ceasing and desisting of this pretend authority and bogus forms is a key performance indicator as to when Columbia starts to take compliance to laws and regulations seriously. It has

before proceeding with the work." Code officials are duly authorized government officials and PA constitutionally can not delegate this authority to them. Columbia requires property owners to use a plumber to who has paid in money and time to get a bogus "Operator Qualification Card (Form C-3363)[31] – qualification		been since 2016 that I have complained about this. The first communication with Columbia July 2016 they asserted the authority of this document. Page 23 --*4.3 ABANDONED, TEMPORARILY DISCONNECTED, OR PARTIALLY REPLACED** *The following are additional requirements for abandoned, temporarily disconnected, or partially replaced customer owned service lines and meter setting installations.*

[31] This document has been used apparently since 2004.

APPENDIX G - Forms

Form 1 – C-3363, "Operator Qualification Card"

Operator Qualification Card

Please **PRINT CLEARLY** (Contractor must complete all information on top portion only)

Name: ____

Employer (or) Company Name: ______________________________

Qualifying Agency: ____________________________________

Qualification ID# : ☐☐☐☐☐☐☐☐☐☐☐☐

Job Address (Include City) ______________________________

Operator Qualification Work Performed by Person Above

Service Line ○ New Installation ○ Renewal ○ Repair / Other

Meter Setting ○ New Installation ○ Renewal ○ Repair / Modification / Relocation

I attest that all work performed and materials used fully comply with all Federal, State, and Local rules, regulations, codes and standards, and all applicable Columbia Gas Policies and Procedures, regulations, and standards, including, but not limited to: 49 CFR 192, Subpart N; Standards for Customer Service Lines, Meters, and Regulators; Tariffs; and Approved Materials for Gas Piping on Customer Owned Service Lines. I further attest that I am enrolled in a Drug and Alcohol plan in accordance with 49 CFR 199. I understand and agree that Columbia's acceptance of a Qualifier's written program shall in no way constitute an assumption or acceptance by Columbia Gas of responsiblity for the installation or repair work performed by me, and I remain responsible for any work performed.

Signature: ______________________________ **Date:** ____/____/____

Note: Operator Qualication Cards can be printed from: www.columbiagasohio.com/business/plumbers or www.columbiagaspamd.com/products_services/plumber_information.htm

Form C – 3363 (11/ 04)

Information Below - For Columbia Use Only

PSID: ☐☐☐ ☐☐☐ ☐☐☐ **SEQ:** ☐☐

☐ **No Gas Service Established**

(Columbia Action Required)

○ Curb valve - Leaks through or out; Requested stop change

○ Other ______________________________

(Contractor Requirement(s) that Failed)

○ **Qualifications not valid and/or OQ card completion unacceptable***

○ **Unable to visual service line where required***

○ **Service Line / Meter Setting installation violation(s) ***

○ **Service Line / Meter Setting failed pressure test(s) ***

○ Service Line / Meter Setting required clearances not met

○ Non OQ related problem(s)

Name (*print*) ______________________ **Date:**___/___/___

*Note: Selections indicated in *BOLD* require card collection - Leave blank OQ replacement card

☐ **Established Gas Service**

Name (*print*) ________________ **Date card picked up:** ___/___/___

Important

Proper Completion Requirements!

- Card must have all contractor information (top portion) properly filled out. *Please note: You may enter data into each required field prior to printing.*
- Card must be legible.
- Card may not have the signature electronically duplicated.
- Card must be protected from the elements such as rain, frost, snow, etc.
- All applicable qualification work performed by an individual on a meter setting and/or service line must be marked. Blacken or make a distinctive checkmark in appropriate circle(s).
- All individuals, not just the crew leader, who are performing qualification work on a meter setting and/or service line, and who are not directly observed by a qualified individual, must leave a properly filled out Operator Qualification card.

WARNING!

Fraudulent or misuse of cards may ultimately lead to an individual or company being banned from working on Customer owned facilities in Columbia Gas of Ohio's or Columbia Gas of Pennsylvania's service areas.

under federal regulations, required for installation, replacement or repair of service lines and/or meter settings." This card is meant and is used to deceive and defraud private property owners and their plumbers. Department of Transportation authority over transportation, including pipelines, stops upon delivery. This document forces a private plumbing company or individual to make a false attestation. *"I attest …fully comply with all*	***49 CFR § 192.513*** [33]***Test requirements for plastic pipelines.*** *(a) Each segment of a*	*(a)* ***Abandoned service lines shall not be reinstated*** *– regardless of material."* The PA Energy Consumer Bill of Rights applies and property owners must be protected from Columbia's wrongful acts. *Consumers have (E)The right to be protected from unfair, deceptive, fraudulent, and anti-competitive practices of providers … natural gas service.* **The results of this rate case must be the vehicle to protect consumers.** **Those 563 plus, home owners and customers who have been victiums over the years of**

[33] https://www.law.cornell.edu/cfr/text/49/192.513

Federal, State and Local … Including 49 CFR Subpart N …" [Qualification of Pipeline Personnel]. Pipeline personnel are utility employees or contract workers. Through these misrepresentations, it forces and deceives these plumbers to pay and receive training and a blood test as if they were employees or contract workers working on utility owned pipelines. This practice is a restraint of trade. Property owners pay more for this type of interference by Columbia.	*plastic **pipeline** must be tested in accordance with this section. (b) The **test procedure must insure discovery of all potentially hazardous leaks** in the segment being tested. (c) The test pressure must be at least **150 percent of the maximum operating pressure** or **50 p.s.i.** (345 kPa) gage, whichever is **greater.***	**Columbia's wrongdoing must be made whole prior to any rate increase.** 49 CFR 49 513 is part of the 49 CFR Part 192 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS After all the problems NiSource and Columbia Gas had with violations of Pipeline Safety Act with over

It is in the public interest, as a supervisor, for the Commission to stop Columbia from misrepresenting private property owner's requirements. The Plumbers Guide requires customer's service lines to be pressure tested at **90 P.S.I.G.** Federal regulations at Section 192.513 is at 55 PSIG. On private property the standard is at 3 PSIG. 90 P.S.I.G is destructive testing, is dangerous to people and harmful to property.		pressurization of pipelines with operations in Massachusetts and Washington County why these internal procedures have not been fixed is incomprehensible. The Commission should not consider additional rates for Columbia's good management.

Columbia does not comply with the requirement to maintain its distribution in conformity with industry standards. Those standards would include ISO 55000 Asset Management, ASTM E2279 … Guiding Principles ... Asset Management; ISO 9000, Quality Management, ISO 31000 Risk Management…	*Title 66 § 2205. Duties of natural gas distribution companies.* *(a) Integrity of distribution system. --* *(1) Each natural gas distribution company shall maintain the integrity of its distribution system at least in conformity with the standards established by the Federal Department of Transportation* ***and such other standards practiced by the industry in a manner*** *sufficient to provide safe and reliable service to all retail gas customers connected to its system consistent with this title and the commission's orders or regulations.*	Built-in and careful compliance to standards would have greatly improved the operations of Columbia Gas. The use of standards improves operations with improved internal controls. Working within standards is an asset – working outside of standards can destroy a company. That is what happened in Massachusetts. NiSource was forced to adopted ANSI/API 1173 - *Pipeline Safety Management Systems*. API 1173 references and is partially based upon ISO 55000 Asset Management. Adopting API 1173 is good, but it appears to have taken excessively

		long to incorporate in practice. There is no good reason to *slow roll* this obligation.

Conclusion:

This table chart never goes away – This chart data of which NiSource and Columbia Gas of Pennsylvania provided is a reflection and a product of poor internal controls that result in unjust and unreasonable rates ---- *"any such rate or charge that is not just and reasonable is declared to be unlawful."* (15 U.S.C. COMMERCE AND TRADE § 717c - Rates and charges and PA Title 66 § 1301). This proposed annual increase of Columbia Gas of Pennsylvania rates of $98,300,000 must be rejected in its entirety as it does not serve in the public interest. This rate request and existing rates are unjust, unreasonable, and unlawful.

Rates should be decreased to the extent they become lawful, reflecting due consideration all the strands of public interest. Individual customers and property owners must receive restitution for harm caused by Columbia's actions as these are some of the strands of public interest. NiSource and Columbia do not change behavior unless forced to, they seem incorrigible; therefore, I suggest a team of experts reporting to the PUC but paid for by Columbia Gas to oversee their operations to supervise this company's correction efforts of installing adequate internal controls into their operations. Otherwise, take the path of Massachusetts. We need to resolve the crisis of trust without delay.

	~ No. of Customers (In 000)	Miles of Pipe	Calculated Miles of pipe per customer	Miles of Bare Steel and Cast Iron	Rate Base ($ 000,000)	Calculated Rate Base Per Customer $	
NIPSCO	840	17500	.020	23*	1700	***2024**	
COH	1500	20200	.013	2000	3200	2133	
CKY	137	2600	.019	2600	327	2387	
CVA	274	5300	.019	140**	850	3102	
CMD	34	660	.018	50	149	4382	
SUB TOL	2785				6226	2236	Ave
CPA	433	7700	.018	1200	2400	**** 5545**	
	3548				8626		

RELIEF

I respectfully request that the Commission take the following actions:

A. Investigate concerns and validate Columbia's full and earnest investigation of the contents of my complaint.

B. Rule that art of a rate increase or decrease is provided based on reliable assurances of **'actual legitimate cost'** of property owned by Columbia Gas of Pennsylvania. The level of assurance must be provided by competent independent auditors and must comply with the definition provided in 2 CFR § 200.7.

C. Rule that a determination of just and reasonable rates can not begin until there is reasonable assurance Columbia's financial performance is based upon **'actual legitimate cost'.** The data from themselves and the parent company show the rate base – thus rates are not reasonable. This chart on its own is substantial evidence of that fact.

D. Reconsider and rule in the letter and spirit and limitations of the Hope decision as provided in this Complaint; (FEDERAL POWER COMMISSION et al. v. HOPE NATURAL GAS CO. CITY OF CLEVELAND v.

SAME Decided Jan. 3, 1944, https://www.law.cornell.edu/supremecourt/text/320/591) particularly *Paragraph 54 [T]he Commission's rate ORDERs* ***must*** *be founded on* ***due consideration of all the elements of the public interest*** *which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act if that Act be applied as an entirety. See, for instance, §§ 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. §§ 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. §§ 717c(a—d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking.* ***But its very foundation is the 'public interest',*** *and the* ***public interest is a texture of multiple strands****. It includes* ***more than contemporary investors*** *and contemporary consumers.*

The needs to be served are not restricted to immediacy, ***and social as well as economic costs must be counted.***

Hope Paragraph 6 *'No greater injustice to consumers could be done than to allow items [such] as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12.*

Confirm the primary mission of the Pennsylvania Public Utility Commission and the purpose of this rate case is not to balance the needs of consumers and utilities, but to provide due consideration of all the elements of the public interest including current long term social and economic needs and costs.

E. Rule that Columbia Gas of Pennsylvania must use the COSO Integrated Internal Control Framework as asserted in the NiSource 10-K and applicable parts of the GAO Green Book. Also rule that Columbia Gas has or has not complied with this self-assertion by management, and that material weaknesses, significant deficiencies, and deficiencies must be disclosed to the Commission ad others and be corrected.

F. Rule the Commission is or is not using applicable parts of the GAO Green Book on Internal Controls as required by Pennsylvania Management Directive of the Governor's Office -- Standards for Internal Controls in Commonwealth Agencies 325.12 Amended (2018).

G. Rule that the Commission and Columbia Gas must use generally accepted audits as applicable. Generally accepted audits are expressed in the GAO Yellow Book. Management Directive of the Governor's Office -- Performance of Audit Responsibilities 325.3 Amended (2011)

H. Rule that the Commission and Columbia Gas are subject to the requirement as applicable to 2 C.F.R. § 200: e.g. § 200.61 Internal controls; § 200.303 Internal controls; § 200.404 Reasonable costs; § 200.110 Effective/applicability date; 200.434 Contributions and donations; § 200.504 Frequency of audits; § 200.514 Scope of audit; § 200.6 Auditee; and other applicable sections of this Federal regulation.

I. Rule that annual audits must include an assurance statement and identification of and material weaknesses, significant deficiencies and deficiencies, and a corrective action plan with dates of progress – if any.

J. Rule that Columbia must correct its accounting to the extent that rates and charges are just and reasonable and in conformance with integrated internal controls and independent and competent audits. Additional details are included in the body of this complaint.

K. Rule that Columbia Gas must satisfy the corrective actions identified by Federal Officials and NiSource Management promises to correct safety deficiencies in records, processes and facilities as a result of the disaster with Columbia Gas of Massachusetts and provide the Commission and the parties of this rate case, that items identified by Federal officials have or have not been corrected at Columbia Gas of Pennsylvania's facilities.

L. Rule that Columbia Gas must recognize boundaries and rights as provided in private property deeds. The authority of Columbia gas must be consistent with laws, regulations, and legal portions of

Columbia's Tariff. In addition, **Columbia does not have the right to trespass, interfere, replace, or maintain or abandon private property** -- **<u>Columbia does have a right to reasonable access to its own property. On what basis did Columbia inspect a heat exchanger on private propery by people who may not be qualified to test and inspect heating systems?</u>**

M. Rule that Columbia must recognize Pennsylvania Utility law Title 66 section 102 regarding basic definitions and concepts such as: facilities (owned by a public utility – tangible and intangible. Private property owners also have tangible and intangible property), service line (always owned by a public utility), customer's service line (never owned by a public utility, Rate Base (property of a public utility which is used and useful in the public service – private property is not used in public service). The Commission nor Columbia have the authority or jurisdiction to change these definitions and must apply them as enacted.

N. Recognize safety concerns and order corrections that have been observed that provide an undue risk to public safety. These include: placing meters in unsafe locations such as under a window so there is no safe access to shut off the gas in an emergency; not installing curb valves on service lines – in an emergency, there may not be a curb valve with an owner's name thereby putting first responders and others at risk in an emergency; not complying with industry standards in service line sizes – thereby insufficient energy is supplied to the home making the service to the home incapable of using the latest and most efficient appliances; installing service lines without quality assurance processes and documented assurance of conformance with requirements.

O. Order the withdrawal of the Plumbers Guide as it declares untruths and harms property owners and private plumbing contractors. Order that Columbia come clean with individuals who have been harmed and encourage Columbia to provide restitution to those harmed. Columbia has no right to misrepresent its authority.

P. **Deny an increase in the Company's rates that cannot be fully justified by the Company or that is unjust, unreasonable, unduly discriminatory, or otherwise inconsistent with the Public Utility Code, sound ratemaking principles, and public policy;**

Q. Determine the justness and reasonableness of the Company's current and proposed rates; and

R. Grant such other relief that the Commission deems necessary.

S. I file this Formal Complaint to ensure that the Commission will fully and fairly deal and adjudicate issues pertaining to whether the Company's existing and proposed rates and internal operations are unjust, unreasonable, unduly discriminatory, or otherwise unlawful.

RCC June 16, 2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**		
	:		
v.	**:**	**Docket No.**	**R-2021-3024296:**
	:		
Columbia Gas of Pennsylvania, Inc.	**:**		

SURREBUTTAL TESTIMONY OF RICHARD C. CULBERTSON

July 22, 2021

Introduction

Q Please state your name and address.

A My name is Richard C. Culbertson. My address is 1340 Bower Hill Road Pittsburgh, Pennsylvania 15243.

Q What is the purpose of this Surrebuttal Testimony?

A In this Surrebuttal Testimony, I respond to the Rebuttal Testimony of Columbia Gas Witness Mark M Kempic Columbia Statement No.1-R July 14, 2021, and by reference C. J. Anstead. Statement No. 14-R (Public). I do not respond to all of the Company's Rebuttal addressing the issues presented in my Direct Testimony. However, this should not be interpreted to mean that I agree with the Company's Rebuttal on those issues or that I believe the companies responses are persuasive.

Q Have you previously submitted testimony in this docket?

A Yes. I submitted Direct Testimony on June 16, 2021.

Q What is your educational and professional background?

A Graduated from what is now California State University Northridge, BS Business Administration – Management, Pepperdine University MBA.
Graduate of GE's internal -2 year Financial Management Program, Certified – CFR 49 Transportation, Certified Lean Six Sigma Black Belt.

Q Memberships in any professional associations or the like?

A Thirty-one-year member of the National Management Association (Current Vice President of local chapter), a 21-year member of ASTM E53Asset Management (Current Chairman of the Committee), 6-year member of ISO TC 251Asset Management (Current Membership Secretary (ASTM/ ANSI / U.S. delegate to. international meetings), 6-year member, board member, and Senior Fellow of Asset Leadership Network. (These are all volunteer positions.)

1 **Q Professional Career Work?**

40-year career with GE and Lockheed Martin (Lockheed Martin is the Largest Government contractor in the world) and I was their leading subject matter expert in asset management – the management and accounting of company and Government property. Had operations management responsibility of a large diverse sector and acquired extensive business management knowledge and skills. 50 years plus involved in personal and family real estate investments, primarily single-family resident homes. Most work we do ourselves.

2

3 **A Have you ever filed a formal complaint against a public utility?**

I have been a customer of public utilities in states – California, New York, New Jersey, Maryland, Virginia, and Pennsylvania. I filed my first formal complaint against Columbia Gas of Pennsylvania on May 8, 2017, because they interfered with my business and my real property. While the property was going through foreclosure in 2015 they “abandoned” the customer’s service line, which is an appurtenance of this private property as if they owned my customer’s service line. Then they forced me to replace my customer’s service line, otherwise, they would not provide gas service.

What they did was when gas service was not used at the property for two years, because of the foreclosure for the property, they abandoned (disconnected it from the main distribution line) wrote off their service line. With this, they administratively abandoned my customer’s service line, even though my customer’s service line remained intact and was separated from Columbia’s service line by a curb valve.

Informally, I complained through Columbia’s ethics department and management up to Mr. Kempic, President of Columbia Gas of Pennsylvania and Mr. Hamrock, CEO and President of NiSource. I got no response from Mr. Kempic, except through Mr. Hamrock. They would not release my property for use. Eventually, I had to replace my customer’s service line with the same ASTM D2513 plastic pipe. They are indistinguishable. After that, Columbia replaced their service line to the property. I understand the cost was around $13,000. From this, I concluded my experience was a deliberate scheme to pad their rate base.

The formal complaint filed May 8, 2017, of which still has not been dispositioned by the PUC.

This is my first Formal Complaint against a public utility in a rate case.

1 **Q What is your experience with 49 CFR Transportation?**

When I was part of the management team of the Shippingport Nuclear Decommissioning Project. I had diverse responsibilities, property management (company and Government), transportation, solid waste management, procurement, contracts, and site services. As part of the job, I had to be DOT certified in the Transportation of Hazardous Material.

Here, one of the most important issues is the jurisdiction of the Department of Transportation. 49 CFR is under the authority and responsibility of the Federal Department of Transportation, on surface, primarily on interstate highways, rail pipelines.

The DOT provides the regulations over the public highways. DOT does not provide regulations of the movement of goods on private property. DOT does not provide regulations beyond delivery at the destination. At Shippingport, we had a thousand-ton pressure vessel to move. We moved it on Duquesne Light property down to the Ohio River onto a barge. Once it was on the barge, ready to move, it became subject to 49 CFR and had to be properly placarded, etc.

It applies in this rate case and the operations of Columbia Gas of Pennsylvania because the delivery of Gas, per the Columbia Gas tariff, is at the Curb valve or property line. (Columbia Gas Tariff "7.1 Point of Delivery)

"The point of delivery of gas to a customer shall be at the outlet side of the curb valve, or the property or lot line if there is no curb valve, at which point title of the gas shall pass to the customer."

2

1 **Q So for gas service of Columbia Gas to your and others' property, once delivery at the property line takes place, DOT 49 CFR Transportation 192 "Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards" no longer applies?**

2

3 **A** That is correct. 49 CFR Transportation is not applicable. Another illustration – I own a motor home that is about 100 inches wide – it cannot be any wider than that when I travel down the highway. When I am on my property or a campground I can extend the width with a slide-out. The DOT regulation is not applicable on private property. Private property is outside the jurisdiction of Columbia except for access to their own property, which is the gas meter. When Columbia gas goes beyond the authority of access to their meter – on private property, they are trespassing.

4

5 **Q Regarding M. Kempic's Statement No. 1-R Page 9 of 10, he refers to Columbia Statement No. 14-R, the rebuttal 13 testimony of Columbia witness Anstead, and Public input testimony by Mr. Hicks. Your reaction?**

6

7 **A** It would have been more appropriate for Mr. Kempic to address Mr. Hicks' testimony of events that occurred several years ago. Mr. Kempic has a legal background and has been responsible for the management of CPA for several years – whereas Mr. Anstead has only been at CPA for a few months, coming from Ohio with a background in quality, operations, and risk management. It does indicate Mr. Kempic is familiar with and agrees with Mr. Anstead's testimony and Columbia's abandonment of private property of others.

8

9 **Q What about the comment Mr. Kempic made regarding NiSource being forced to adopt API 1173?**

10

11 **A** Pennsylvania public utility law requires.
PA Title 66 § 2205. Duties of natural gas distribution companies.
(a) Integrity of distribution system. --

(1) Each natural gas distribution company shall maintain the integrity of its distribution system at least in conformity with the standards established by the Federal Department of Transportation and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service.

12

11 **A** For a new regulations PA PUC regulation *§ 59.33. Safety. Requires a) Responsibility. Each public utility shall at all times use every reasonable effort to properly warn and protect the public from danger and shall exercise reasonable care to reduce the hazards to which employees, customers and others may be subjected to by reason of its equipment and facilities. ... The amendment or modification shall take effect **60 days** after the effective date of the Federal amendment or modification,*

NiSource did not nor CPA get serious with the adoption of API 1173 until after the Massachusetts disaster. See the November 21, 2018 Press Release of the Governor's Office https://www.mass.gov/news/baker-polito-administration-announces-utilities-will-adopt-comprehensive-pipeline-safety

Having plans to adopt and implementing a standard that was published in 2015 and years after not implementation is not compliant with PA Title 66 § 2205 nor PA PUC regulation § 59.33. Safety.

Columbia/ NiSource has not implementing industry standards—ISO 9000, Quality Management, ISO 55000, Asset Management, and the COSO (2013) integrated internal control frame work. This has been has been harmful yo Columbia and put customers at risk..

1

2 **Q** **Regarding *July 14, 2021, C. J. Anstead's, Statement No. 14-R (Public) Page 1 and 2 of 4 (General Manager and Vice President.)***

Page 1

11 Q. Mr. Anstead, are you familiar with the testimony of Michael Hicks, Sr.,

12 given at the public input hearing on June 16?13 A. Yes. Mr. Hicks indicated that he is currently without service from Columbia because

14 the Company instructed him to replace the <u>service line</u> at his residence at 2 Eighth

15 Street in Uniontown, Pennsylvania, and he was unable to afford to pay a plumber the

16 estimated cost of $6,000 to do so. Mr. Hicks was not specific as to the timing of the

17 discontinuation of this natural gas service or as to his attempt to restore service.

18 Q. Has Columbia looked into its records regarding the discontinuation of

19 service at 2 Eighth Street in Uniontown?

20 A. Yes.

Page 2 "11 Q. Did the <u>customer service line</u> at 2 Eighth Street in Uniontown have

12 anything to do with the inability to restore Mr. Hicks' service in January

13 of 2011?

14 A. No. Service could have been restored in January of 2011 without any requirement to

15 replace the <u>customer service line</u> because Mr. Hicks' service line had not yet been

16 abandoned under Section 59.36 of the Commission's regulations."

What is wrong with these questions and answers?

3 **A** First of all C.J. Anstead became its the new VP, Gas Operations and apparently became the new General Manager and Vice President of Columbia Gas of Pennsylvania very recently. He came from Columbia Gas from Ohio and appears to

have an excellent background in Gas operations construction, safety, and risk management. https://www.columbiagasmd.com/our-company/about-us/our-leadership/c-j-anstead

State laws and regulations are different in Ohio and Pennsylvania.

It does not appear he has a background in accounting, asset management nor contracts. His answers are the same Columbia's rational as in the past for abandoning private property.

I believe he should have reviewed these issues independently and taken the appropriate action based upon the NiSource Code of Business Conduct. *OUR COMMITMENT TO FAIR AND ETHICAL DEALINGS WITH OTHERS -- Comply with all applicable … laws and regulations*.

Unwittingly, Mr. Anstead may have become part of the problem. He may want to correct that.

As lesson for me a long time ago – do not interfere with customer's property beyond what is allowed in the contract.

Secondly it is not a "customer service line". It is "customer's service line".

Law: *TITLE 66 PUBLIC UTILITIES*

§ 102. Definitions.

"Customer's service line." The pipe and appurtenances owned by the customer extending from the service connection of the gas utility to the inlet of the meter serving the customer."

"Service line." The pipe and appurtenances of the gas utility, …

Notes: ***1984 Amendments***. *Act 22 added the defs. of* ***"customer's service line"*** *and* ***"service line,"***

Now a "customer meter" that is used in 49 CFR 193 Definitions is utility owned.

The proper use and recognition of ownership with these terms is paramount.

A "customer's service line" may not be owned by a customer. The definition is wrong when a customer is a renter. The customer's service line is owned by the property owner in Western Pennsylvania. In other states the service line is owned by the utility.

In Western Pennsylvania Columbia Gas has what is referred to as "stub service".

A *18 CFR Part 201 - UNIFORM SYSTEM OF ACCOUNTS -- 380 Services.*

"A. This account shall include the cost installed of service pipes and accessories leading to the customers' premises.

B. A complete service begins with the connection on the main and extends to but does not include the connection with the customer's meter. A stub service extends from the main to the property line, or the curb stop.

C. Services which have been used but have become inactive shall be retired from utility plant in service immediately if there is no prospect for reuse, and, in any event, shall be retired by the end of the second year following that during which the service became inactive unless reused in the interim."

Note: There is a flaw in C. "no prospect for reuse" financial retirement of the asset *by the end of the second year*. PA PUC Section 59.36(2) fixed the flaw. Again, this is a flaw in using an arbitrary time frame. This requires financial recognition for accounting purposes based upon the financial definition of "asset" in FASB Financial Concept 6 paragraph "*25. Assets are probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events."*

"Retirement" does not mean "abandonment." In GAAP now, such assets would be reviewed for impairment testing and would not be written down arbitrarily.

Nevertheless, a customer's service line as defined in Pennsylvania Title 66 is not to be part of "plant in service" by the utility – and is the responsibly of its owner.

1

2 **A** *"any requirement to replace the customer service line because Mr. Hicks' service line had not yet been abandoned under Section 59.36 of the Commission's regulations"* *"§ 59.36. Abandonment of inactive service lines."* 59.36 is not about customer's service lines it is about service lines --- utility property. The Commission does not have the authority over private property. Abandonment is a disposition of property by the owner. Columbia has no authority whatsoever to abandon property of which it does not own.

Furthermore § 59.36. **"***(2) Service lines which have been inactive for 3 months and for which there is a reasonable prospect of future use shall be shut off ... A review of the status of inactive lines **shall** be made annually, at periods not exceeding 15 months. Lines which no longer qualify for retention [no prospect of future use] shall be abandoned under paragraph (1).*

With this PUC regulation, Columbia could not legally abandon a customer's service line nor its service line without proper review. Certainly, they should not abandon a service line when someone was living at the premises, as was the case of Mr. Hicks.

3

4 **A** It is important to understand the terms abandon and abandonment and the context in which they are used.

Real property cannot be abandoned. Certainly not by a public utility service provider. It is always owned by someone who has responsibility for its use and condition. Personal property can be in some cases be abandoned, by its owner.

WEX Legal Dictionary *"Abandoned Property --Personal property left by an owner who intentionally relinquishes all rights to its control. Real property may not be abandoned."* https://www.law.cornell.edu/wex/abandoned_property

Key terms: owner, personal property and real property. A customer's service line is the real property of the owner. A service line is the personal property of Columbia Gas.

A ***Title 49: Transportation***
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart A—General

§192.3 Definitions.
As used in this part:

Abandoned means permanently removed from service.

https://www.law.cornell.edu/cfr/text/49/192.3

This means the term "abandoned" is confined to Part 192 of Code of Federal Regulations Title 49 Transportation that is under the responsibility of the Federal Secretary of Transportation. Abandon vehicles, for example, are covered under 49 CFR Part 591. The customer's service line – residential private real property is not under the jurisdiction of the Secretary of Transportation, nor directly by the Pennsylvania Public Utility Commission.

The customer's service line is covered by the Pennsylvania Construction Code and the municipality's adoption of specified construction standards – such as the International Gas Fuel Standard. Details of laws and regulation important CPA is required to know them.

A Columbia does not have good control of its procedures. To illustrate:

STANDARDS FOR CUSTOMER SERVICE LINES, METERS, AND SERVICE REGULATORS (Plumber's Guide) (Approved by anonymous and *Revised: 06/01/2021 PROPRIETARY*)

1.*6 DEFINITIONS*

Abandoned – A service line is classified as abandoned when it has been physically separated from the main and plugged or sealed.

*4.3 ABANDONED, TEMPORARILY DISCONNECTED, OR PARTIALLY REPLACED**

The following are additional requirements for abandoned, temporarily disconnected, or partially replaced customer owned service lines and meter setting installations.

(a) Abandoned service lines shall not be reinstated – regardless of material.

https://www.columbiagaspa.com/docs/librariesprovider14/contractors-and-plumbers/plumber-qualifications/plumber's-guide.pdf?sfvrsn=9

Here, Columbia deceptively applies what is required for utility property and applies the Federal Transportation Regulations to requirements of private property.

Q What is wrong with this question and answer?

17 "Q. Was the service line to 2 Eighth Street in Uniontown eventually

18 abandoned?

19 A. Yes. In November of 2014, Columbia abandoned the inactive service line at that

20 address in compliance with Section 59.36(2). Abandoning an inactive service line

***21 involves physically cutting the connection between the service line and Columbia's* (page 3of 4) main line, and purging the service 1 line of gas."**

A From this testimony, there is no indication that the abandonment of the service line occurred after a proper review as required by the PUC regulation 59.36(2).

Note the switch between the customer's service line and service line. Abandonment of a service line should be rare. Only when there is *"no reasonable prospect for reuse"*. When there is an occupied home there is the prospect for reuse.

For the customer's service line to be abandoned, Columbia must have assumed ownership of the customer's service line. Counter to Pennsylvania Utility law.

§ 1510. Ownership and maintenance of natural and artificial gas service lines.

A public utility <u>shall not be authorized or required to acquire or assume ownership</u> of any customer's service line.
https://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66

A Notice what Columbia did to Mr. Hicks. They abandoned his property outside of the requirements of the PUC regulation ***Section 59.36(2)*** right before winter while he was living in his home in November 2014. If Columbia had followed the PUC regulations and not abandoned the service line, all Mr. Hicks had to do was call for service from Columbia in November 2014 and he would not have had to suffer all of this time.

The service line and the customer's service lines are two distinct items of property – different purposes, different owners under different standards. The service line can be maintained or replaced independently from the customer's service line. The same with the customer's service line, granted at times CPA and their customer must coordinate.

Q So, as an asset management expert, one who writes standards and one who was responsible for internal controls at large highly regulated companies in Pennsylvania -- what is your opinion regarding the risks of Columbia's practice of abandoning other's property?

A I believe organizations are required to have internal control that includes compliance with laws and regulations. I believe individuals and companies are required to obey applicable laws and regulations such as:

https://www.legis.state.pa.us/WU01/LI/LI/CT/PDF/18/18.PDF

3921. Theft by unlawful taking or disposition. lawfully transfers, or exercises unlawful control over, immovable property of another or any interest therein with intent to benefit himself or another not entitled thereto.

§ 3922. Theft by deception.

(a) Offense defined. --A person is guilty of theft if he intentionally obtains or withholds property of another by deception. ...

PENNSYLVANIA UNFAIR TRADE PRACTICES AND CONSUMER PROTECTION LAW 73 P.S. §§201-1 - 201-9.2 https://www.attorneygeneral.gov/wp-content/uploads/2018/02/Unfair_Trade_Practices_Consumer_Protection_Law.pdf

Such a: *(xv) Knowingly misrepresenting that services, replacements or repairs are needed if they are not needed;*

The recent Pennsylvania Supreme Court decision --GARY L. GREGG AND MARY E. v. AMERIPRISE FINANCIAL, INC., could apply to companies who deal with the public under the under Pennsylvania's Unfair Trade Practices and Consumer Protection Law

https://cases.justia.com/pennsylvania/supreme-court/2021-29-wap-2019.pdf?ts=1613570747

Q Page 3 of 4. ***2 Q. After that, did Mr. Hicks contact Columbia about restoring his service?***

3 A. Yes. In December of 2015, thirteen months after the service line had been

4 abandoned, Mr. Hicks contacted Columbia to request the restoration of his service.

5 Since the service line had been physically abandoned, Columbia would have advised

6 him that he would be required to replace the customer-owned portion of the service

7 line.

What is wrong with this statement?

A Here again, we are seeing twisted logic, misrepresentation, and cruelty. It is getting cold again in December 2015. [T]hirteen months after the (utility-owned) service line had been abandoned not in accordance with Pennsylvania PUC regulation as the abandonment was not properly reviewed (no prospect of reuse). Columbia did not put in place the proper control for abandonment.

Yes, there was a NiSource Gas Standard GS 1740.010 Abandonment of Facilities, Reference 49 CFR Part 192.727

1. GENERAL

This standard shall apply to the abandonment or deactivation of <u>pipeline</u> facilities.

An inactive <u>pipeline</u> not being maintained by the Company shall be abandoned.
https://psc.ky.gov/pscecf/2016-00162/cmacdonald%40nisource.com/07222016111805/CKY_R_AGDR1_NUM12_Part2_072216.pdf

This gas standard applies to the abandonment of pipeline facilities –

(49 CFR § 192.3) *Pipeline*

Pipeline means all parts of those physical facilities through which gas moves in <u>transportation</u>, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. A customer's service line is not a utility owned pipeline facility.

NiSource
Distribution Operations

Gas Standard

Effective Date: 07/01/2014	**Abandonment of Facilities**	Standard Number: **GS 1740.010(PA)**
Supersedes: 01/01/2013		Page 1 of 7

<u>Companies Affected:</u>

☐ NIPSCO	☐ CGV	☐ CMD
	☐ CKY	☐ COH
	☐ CMA	☑ CPA

REFERENCE 49 CFR Part 192.727; PA Chapter 59.36

1. GENERAL

This standard shall apply to the abandonment or deactivation of pipeline facilities.

An inactive pipeline not being maintained by the Company shall be abandoned.

(From NiSource Columbia Gas Culbertson2-064 Attachment B Page 1of 7 Culbertson Formal Complaint May 2017)

Again neither reference apply to customer’s service lines.

It gets worse -- *§ 192.727 Abandonment or deactivation of facilities.*

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas;

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed. **(taking the meter)**

There is no requirement for abandonment of service lines.

So what did Columbia/ NiSource do – they used and aggressive abandonment of approach on abandonment of service lines as a means to unjustly and unreasonably expand their rate base. By how much – to be determined.

A *5“Since the service line had been physically abandoned, Columbia would have advised him that he would be required to replace the customer-owned portion of the service line.”* [Speculation but condoning the Columbia’s action.]

There is no such item as a customer-owned portion of the service line. By definition in Pennsylvania Utility law, there is a service line – company property owned property, in the FERC Chart of Accounts, this is charged to account 380 services.

Also in the law, customer’s service line is defined – not utility-owned. This is mixing the ideas that some service lines go from the main to the meter, and stub service extends from the main to the property line. A service line is not a stub service plus a customer’s service line. This is deceptive for the unknowing, Columbia should know.

What is wrong with this statement is just because Columbia abandoned their property not in accordance with Federal Regulation 49 CFR 192.727, PA 59.36 and their internal policy GS 1420.010(PA),they had no right to abandon nor tell Mr. Hicks they had abandoned his property … Columbia should have restored Mr. Hicks service by any means necessary.

Trying to force him to replace his customer’s service line was wrong. In that, Mr. Hicks he did not replace his customer’s service line – that has put him at unreasonable risk and in misery.

1

2 **Q Do you know Mr. Hicks, ever spoken or corresponded with Mr. Hicks outside of the PUC Public Input Hearing?**

3 **A** No

4

5 **Q When did you learn there was something wrong with Columba's abandonment process?**

A July 7, 2016, the first fifteen seconds with Columbia's Customer Service in Ohio – they told me Columbia has abandoned my service line or customer service line and I would have to replace it at my cost and until I did, service could/would not be started.

In my long career in asset management, it is a basic issue that needs to be understood and addressed legally, financially, and physically. In dealing with customer property (U.S. Government Property) rule 1 only the Government can abandon Government property. Abandonment is covered in FAR 45.603 – there are multiple considerations between the Government and their contractors. Contractors cannot abandon Government property. For the Government, one over one approval is required. At Columbia Gas, there does not appear to be any documents of an individual abandonment decision. In the case of my property, after two years a NiSource system generated two work orders, one to pull the meter and one to cut the service line. That is probably what happened to Mr. Hicks. A service technician on a work order was to take out the meter and another service technician to cut the service line. The customer's service line remains intact and undisturbed. Service technicians are non-exempt employees with limited decision making – *PUC Regulation 59.36 "A review of the status of inactive lines* <u>*shall be made annually"* After the work order is cut is not the time to do a review of *"reasonable prospect of future use".*</u> Again in Mr. Hicks' case and my case there appears to be a lack of internal controls with the abandonment process – there are problems with operations, reporting, compliance and safeguarding assets.

6

7 **Q What is the significance of Mr. Hicks' public testimony in this Columbia Gas rate case?**

8 **A** His testimony lays bare material weaknesses of Columbia's and the Commission's internal control systems. Safeguards that were supposed to be in place either were not present or did not work.

The largest problem, here we have the highest officials at Columbia Gas and corporate legal department defending the current process – for years. They either knew or should have known the practice was wrong – taking other's property, causing improper abandonment of company and other's property, improper disposition of assets causing improper acquisition of assets charged to plant in service.

The NiSource nor the CPA policy provides permission to abandon customer's service lines. They did not comply with 49 CFR 192.727. PUC regulations 59.36 nor their own internal policy GS 1740.010(PA) pertaining to utility-owned pipeline facilities.

Mr Hicks' experience resembles my experience with Columbia Gas at 1608 McFarland Road in Dormont.

One can be an exception two is a trend.

The NiSource internal audit of abandonment did not address the abandonment of customer's service lines—even though there has been an outstanding complaint since 2016 on the issue.

The PUC management audit of CPA in 2020 did not cover this issue and the ramifications of improper abandonment.

The legal department took the role of advocating the current process … their legal training should have taken over with efforts to stop the process.

The Corporate ethics system failed with a lack or reporting from those who knew, lack of leadership, investigations, and lack of corrections.

The PUC under Title 66 § 501. General powers. …they wrote a regulation but failed in "its duty to enforce" by orders or otherwise.

With so many internal and external systems failing to protect customers with Columbia's abandonment, this reflects poorly on everything else … nothing can be trusted. There is no assurance of effective internal controls … without that it would be reckless to provide Columbia a rate increase until proper audits, corrections and improvement are made, and the proper assurance of effective internal controls are in place.

1 **Q Page 3of 4 8Q.** ***Could Columbia have replaced the customer-owned portion of the***

9 service line?

10 A. No. Under Columbia's tariff, customers in Fayette County own, and are responsible

11 for maintaining, the portion of the service line that is beyond Columbia's point of

12 delivery at their premises. The point of delivery is designated as the curb valve or, if

13 there is no curb valve, the property line. Columbia's tariff also provides that the

14 customer is responsible for installing, at the customer's expense, the service line to

15 the point of connection to Columbia's main. The Commission has granted limited

16 waivers to these tariff provisions where service line replacement must be done in

17 conjunction with a main replacement project. Since the need to replace the

service

18 line at 2 Eighth Street in Uniontown was not related to a main replacement project,

19 those waivers do not apply to Mr. Hicks' situation.

What is wrong with this Question and Answer?

A Columbia abandoned Mr. Hicks' private property without his knowledge and consent. I believe this was a form of defrauding Mr. Hicks out of his service line. Any cost associated with abandonment and Mr. Hicks property and the replacement of Columbia's service is not reasonable and thus unallowable cost. If Columbia robs Mr. Hicks of his property and Mr. Hicks wants his property back that cost is not a proper, prudent and reasonable business expense under FERC nor 2 CFR 200. Being counter to the tariff is irrelevant.

Q **Page 3 of 4 and 4 of 4** *20 Q.* ***Could Columbia just have restored service through the existing service***

21 line that had been abandoned?

A. No. Whether a service line is company-owned or customer-owned, 1 once a service

2 line has been physically abandoned by severing the connection to Columbia's main,

3 Columbia will not re-introduced service through the abandoned service line.

A Like the previous question. Abandonment of a customer's service line was outside of legal – regulatory bounds. So restoring the customer's service line is also outside of normal prudent operations. This is like if the company had a scheme for when employees were in the customer's homes to look at the meter, they were instructed to take valuables. They get caught – and customers wants their valuables back and Columbia contends they cannot provide restitution because the tariff will not allow it.

It does not make any difference what was taken or dispositioned – it could have been my white truck. And just because Columbia abandons their white truck that does not mean Columbia can abandon my white truck as well. Mr. Hicks' property was his property and if you break it or took it you fix it or bring it back. How Columbia does the accounting for proper restitution is none of his concern.

Those who Columbia harmed with improper abandonment need to be made whole.

This and other unreasonable costs needs to be identified and the rate base adjusted accordingly.

Q Does that conclude your testimony?

A Yes.

Richard C. Culbertson
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July 14, 2021

Honorable Mark A. Hoyer
Deputy Chief Administrative Law Judge
Pennsylvania Public Utility Commission
301 5th Avenue, Suite 220
Pittsburgh, PA 15222

VIA E-MAIL

RE: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania; Docket No. R-2021-3024296

Dear Judge Hoyer:

Attached please find the Columbia Industrial Intervenors ("CII") Statement No. 1: Rebuttal Testimony of Frank Plank.

As shown by the attached Certificate of Service, all parties to this proceeding are being duly served via email only due to the current COVID-19 pandemic. Upon lifting of the aforementioned Emergency Order, we can provide parties with a hard copy.

Sincerely,

McNEES WALLACE & NURICK LLC

By Charis Mincavage

Charis Mincavage

Counsel to the Columbia Industrial Intervenors

Enclosure
c: Rosemary Chiavetta, Secretary (via electronic filing)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of 52 Pa. Code Section 1.54 (relating to service by a participant).

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Charis Mincavage

Charis Mincavage
Counsel to the Columbia Industrial Intervenors

Dated this 14th day of July, 2021, at Harrisburg, Pennsylvania.

CII Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

REBUTTAL TESTIMONY

OF

FRANK PLANK

OF KNOUSE FOODS COOPERATIVE, INC.

ON BEHALF OF

COLUMBIA INDUSTRIAL INTERVENORS ("CII")

JULY 14, 2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

REBUTTAL TESTIMONY OF FRANK PLANK
OF KNOUSE FOODS COOPERATIVE, INC.
ON BEHALF OF
COLUMBIA INDUSTRIAL INTERVENORS

Q. Please state your name and business address.

A. My name is Frank Plank and my business address is Knouse Foods Cooperative, Inc., 53 East Hanover Street, P.O. Box 807, Biglerville, PA 17307-080.

Q. By whom are you employed?

A. I am employed by Knouse Foods Cooperative, Inc. ("Knouse").

Q. Have you ever provided testimony before the Pennsylvania Public Utility Commission ("PUC" or "Commission") or any other regulatory body?

A. Yes. I provided testimony in Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company") 2010 Base Rate Proceeding at Docket No. R-2010-2215623; in Columbia's 2015 Base Rate Proceeding at Docket No. R-2015-2468056; in Columbia's 2016 Base Rate Proceeding at Docket No. R-2016-2529660; in Columbia's 2018 Base Rate Proceeding at Docket No. R-2018-2647577; in Columbia's 2020 Base Rate Proceeding at Docket No. R-2020-3018835; in the FirstEnergy Companies' Third Default Service Plan Proceedings at Docket Nos. P-2013-2391368; P-2013-2391372; P-2013-2391375; P-2013-2391378; and in the FirstEnergy Companies' Fourth Default Service Plan Proceedings at Docket Nos. P-2015-2511333, P-2015-2511351, P-2015-2511355, and P-2015-2511356.

Q. What is your current position with Knouse?

A. I am Manager of Purchasing for Knouse.

Q. What are your duties as Manager of Purchasing?

A. As Manager of Purchasing for Knouse, my duties include purchasing the natural gas, recycled oil, electricity, nitrogen, water treatment, adhesives, pest control services, pallets, and various other items for all of our processing plants. In addition, I have responsibility for developing and negotiating contracts, setting budgets, and providing upper management with projections of costs. My responsibilities further include managing and training personnel that purchase our stockroom items, bulk bins, bulk bin repair parts, machine parts, office supplies, labels, and various other items. I also develop and enforce the policies and procedures for purchasing and receiving, as well as approve purchase orders.

Q. How long have you worked at Knouse?

A. I have worked at Knouse for over 40 years.

Q. What is your educational and employment background?

A. I am a 1976 graduate of Gettysburg Area High School and have attended various seminars on topics such as Fundamentals of Purchasing, Energy Procurement, Managing People, and Negotiating of Contracts. I have also attended numerous Knouse Foods development sessions. In addition to my role as Manager of Purchasing for Knouse, I am a current Board member of the Metropolitan Edison Company/Pennsylvania Electric Company Sustainable Energy Fund. I started working for Knouse in March of 1977 on the shipping docks. In 1980, I moved into the Label/Printing department. In 1983, I was promoted to Private Brand Label Buyer. In 1990, I was promoted again to become the Manager of Purchasing. In 1997, Knouse restructured its Purchasing department. This restructuring included centralizing procurement activities. As Manager of Purchasing, I became responsible for purchasing recycled oil, natural gas, and electricity. I was also the Project Manager for and oversaw the development and installation of a 3MW Solar System at our Peach Glen location, which was completed in January 2011.

Q. Please describe Knouse's operations.

A. Knouse began more than seventy years ago when a group of prominent independent fruit growers in the Appalachian region recognized the enormous potential at their fingertips. Given their shared commitment to raising quality fruit, these growers formed an alliance and began working together as a grower cooperative. The growers quickly became aware of the need for a reliable processor for their fruit. To address this need, they purchased apple processing plants and equipment in Peach Glen, Pennsylvania; Ortanna, Pennsylvania; and Chambersburg, Pennsylvania, thereby creating the cooperative that is Knouse. Today, Knouse processes mainly apples and apple products, but also processes other fresh fruits such as peaches and cherries. The recognized labels under which Knouse processes these fruits includes Musselman's and Lucky Leaf. Knouse currently operates five processing plants in two states.

Q. How many of those processing plants are located in Pennsylvania?

A. Four. Knouse currently has processing plants in Chambersburg, Ortanna, Biglerville, and Peach Glen. Peach Glen is also the location of Knouse's corporate headquarters.

Q. How does Knouse use natural gas in its processes?

A. Knouse uses natural gas in its boilers to produce steam. The steam is used to cook our products and provide heat in our plants. We also use natural gas to heat different areas of our plant through conventional heaters.

Q. Does Knouse use large amounts of natural gas?

A. Yes. We currently use over 400,000 Mcf of natural gas annually.

Q. How does the cost of natural gas compare to Knouse's overall energy consumption?

A. Knouse's natural gas costs comprise approximately 50% of Knouse's overall annual energy budget.

Q. Are any of Knouse's processing plants located in Columbia service territory?

A. Yes. Knouse's Ortanna, Biglerville, Gardners, and Peach Glen plants are located in, and receive natural gas distribution service from, Columbia. Knouse has been a customer of Columbia for at least the past 30 years.

Q. What type of service does Knouse receive from Columbia?

A. Knouse receives only distribution service from Columbia. Knouse purchases natural gas supply from a competitive Natural Gas Supplier ("NGS").

Q. Under what Rate Schedules does Knouse currently receive distribution service from Columbia?

A. Knouse has numerous accounts with Columbia. As a result, Knouse receives distribution service from Columbia under Rate Schedules Large Distribution Service ("LDS"), Small Distribution Service ("SDS"), and Small General Distribution Service ("SGDS"). In previous years, because Knouse has alternative fuel capability, Knouse took LDS, SDS, and SGDS service from Columbia under a flexible rate pursuant to Rule 20 of Columbia's Tariff Pa. P.U.C. No. 9. Due to changes in Columbia's requirements, as well as the increase in the cost of fuel oil, Columbia has been unwilling to offer Knouse a flexible contract. Although Knouse received some type of flex rate from Columbia for approximately 25 years, Knouse's last flexible rate contract with Columbia was dated January 1, 2011.

Q. How have Knouse's natural gas costs changed since the elimination of its flexible rate contract with Columbia?

A. Not surprisingly, Knouse's distribution costs have increased significantly, as Knouse had to begin receiving service under Columbia's full tariff rate, which is considerably higher than Knouse's prior flexed rate. In addition, Columbia requested base rate increases in 2008, 2010, 2011, 2012, 2014, 2015, 2016, 2018, and 2020 (along with the Company's base rate request currently before the PUC). When Knouse was receiving service under a flexible rate contract prior to 2011, Knouse was insulated from these rate increases. Once Knouse moved to Columbia's full tariff rate, the ramification of continued base rate increases further affected Knouse's energy costs. This impact continues and compounds, without any stabilization period, because Columbia continues to file a rate increase every twelve to eighteen months.

Additionally, Columbia's implementation of a Distribution System Improvement Charge ("DSIC") has also affected Knouse's natural gas distribution costs. As I understand it, Columbia's tariff allows for the Company to make a downward adjustment to the DSIC component and other rate components for flex rate customers. Because Knouse is now a full tariff rate customer, Knouse's natural gas costs are further increased upon Columbia's collection of costs through the DSIC.

Q. What is your understanding with respect to how Columbia's $98.3 million rate increase request would apply to Knouse?

A. Although Knouse has several accounts on Columbia's system, for purposes of this question, I am only discussing our Rate LDS account. Columbia proposes to increase Rate LDS by approximately 30%.

Q. Did you submit Direct Testimony in this proceeding?

A. No, I did not. CII membership has been extremely limited over the past decade, with Knouse being the only member for purposes of the current proceeding. The continued prosecution of Columbia rate cases, combined with the continued increases in Columbia's rates, limits the discretionary budgets of large commercial and industrial customers needed to fund participation in this matter.

Q. Why are you submitted Rebuttal Testimony in this proceeding?

A. My understanding is that the Office of Consumer Advocate ("OCA") is proposing a 36.5% increase to Rate LDS, while the Office of Small Business Advocate ("OSBA") is proposing a 39.9% rate increase to Rate LDS. In addition, the Bureau of Investigation and Enforcement ("I&E") has indicated that, if Columbia receives less than its full requested rate increase, Rate LDS should only get a limited, if any, scaleback.

Q. What is the purpose of your Rebuttal Testimony?

A. I am extremely concerned about the impact that the parties' proposed rate increases would have on Knouse’s operations, Knouse’s workforce, and the Knouse community. Knouse has had to contend with Columbia seeking rate increases approximately every twelve to eighteen months for the past decade. Moreover, Knouse has faced several challenges during the course of the COVID-19 pandemic, and Knouse cannot determine the future impact of the pandemic. For example, Knouse's processing is dependent on the availability of crops; however, uncertainty remains as to whether farmers will have the workforce needed to pick the fruit off of the trees.

Columbia's proposed 30% increase would already significantly impact Knouse, especially in light of the fact that natural gas costs are 50% of Knouse's energy budget. The OCA and OSBA proposals would only exacerbate Columbia's proposal, resulting in a damaging impact on Knouse's energy costs. When an approximate 40% increase is combined with the uncertainty that Knouse faces due to the impact of the COVID-19 pandemic, the results are especially alarming.

Q. What are you suggesting for purposes of Columbia's requested rate increase?

A. If the PUC allows Columbia to increase its rates at this time, I would ask that the OCA and OSBA rate allocation proposals be denied, as 36% to 40% increases would be excessive to large customers. Similarly, if the PUC grants Columbia less than its requested $98.3 million, I would ask that the PUC deny I&E's proposal, and instead, provide Rate LDS with a scaleback equivalent to the other parties.

Q. Does this conclude your testimony at this time?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2021-3024296
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

PSU Statement No. 1

DIRECT TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

Dated: June 16, 2021

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. a consulting firm focused on regulatory and market issues. My business address is 4226 Yarmouth Drive, Suite 101, Allison Park, Pennsylvania 15101. I am presenting testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU").

Q. DO YOU HAVE ANY QUALIFICATIONS OR OTHER SPECIALIZED KNOWLEDGE THAT WOULD ASSIST THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") IN ITS DELIBERATIONS IN THIS CASE?

A. Yes.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.S. in Chemical Engineering from Carnegie Mellon University and an MBA from the University of Pittsburgh. Additionally, I am a Registered Professional Engineer in the Commonwealth of Pennsylvania.

Q. BRIEFLY DESCRIBE YOUR RELEVANT BUSINESS QUALIFICATIONS.

A. I have conducted a consulting practice for the past 25 years focused on regulated and deregulated energy company strategy, market strategy, and regulatory issues. During 2004 and 2005, I undertook a consulting assignment as the Vice President of Consumer Markets for ACN Energy. ACN is a gas and electric marketer that is active in eight states. Prior to my consulting practice, I worked at three major energy companies for a total of 19 years. Most recently I was Vice President of Marketing for Equitable Resources. In that function I was responsible for the development of the company's deregulated business strategy.

Prior to that I was Vice President of Marketing for Citizens Utilities, responsible for gas, electric, water and wastewater marketing activities in several service territories within the United States. The gas and electric utility operations were in Vermont, Louisiana, Arizona, Colorado, and Hawaii. Under my direction, Citizens initiated commercial and industrial transportation and supply services at its gas operation in Arizona. I also directed significant gas supply contracting activities with large industrial and commercial customers in Citizens' gas operation in Louisiana.

Before that, during 1988 through 1994, I was the Marketing Director at the Peoples Natural Gas Company where I was actively involved in many gas transportation programs as the company relaxed transportation requirements so that customers would have supply choices.

In summary, I have considerable experience in several states involving residential, commercial, and industrial customer energy procurement, regulatory issues and industry restructuring programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. Yes, I have appeared before the Commission in numerous gas and electric regulatory proceedings. I have been involved in the previous base rate cases of Columbia Gas of Pennsylvania, Inc. ("Columbia," "CPA," or the "Company") filed in 2008, 2009, 2010, 2012, 2014, 2015, 2016, 2018, 2020 and in its 2017 purchased gas cost case. Additionally, I provided testimony on a variety of issues relating to energy procurement, industry restructuring, and demand response before regulatory Commissions in Arizona, Maryland, New Mexico, Illinois, Ohio and the U.S. Virgin Islands.

I. <u>ISSUES</u>

Q. WHAT ARE THE ISSUES YOU WILL DISCUSS IN THIS TESTIMONY?

A. Specifically, in my direct testimony I will address Columbia's base rate requests and then address Columbia's Cost of Service Study ("COSS") and recommendations. As in the past the Company conducted two COSS and produced an average COSS. The process it used is not reflective of cost causation and the recommendations made should not be accepted.

II. <u>PENN STATE SERVICE</u>

Q. WOULD YOU BRIEFLY DESCRIBE PENN STATE'S SERVICE FROM COLUMBIA?

A. Yes. Penn State is a major sales and distribution service customer of Columbia at its University Park campus and at its Beaver, Fayette, Mont Alto, and York Campuses as well as the Biglerville Ag Extension Farm within the Commonwealth. In 2020, Penn State received approximately 2 million Dth through distribution service from Columbia. At the University Park campus PSU takes service from two primary accounts. The two campus steam plants, including a combustion turbine-generator with a heat recovery steam generator, are serviced from three meters representing about 91% of the campus load and make up one account. A variety of campus buildings that are served from about 50 meters, representing about 9% of the campus load, make up the other account.

Q. WHAT PIPELINES DELIVER GAS TO THE COLUMBIA DISTRIBUTION SYSTEM THAT SERVES THE UNIVERSITY PARK CAMPUS OF PENN STATE?

A. The State College area and other areas of Centre County receive gas that flows into the Columbia distribution system through two Points of Delivery ("PODs") from interstate pipelines. About eight miles east of State College are two interstate pipelines, Dominion Transmission ("Dominion" or "DTI") and Texas Eastern ("TETCO"). Columbia removed access to a third pipeline supplier by closing the Snowshoe Lateral on June 30, 2018. Prior to closing the Snowshoe Lateral which connects to the Columbia Gas Transmission ("TCO") interstate pipeline, it was the main delivery route to State College for Columbia's residential, commercial, and industrial customers. TCO was affiliated with Columbia until 2016 when the parent corporation, NiSource, sold TCO to TC Energy. Columbia then abandoned the Snowshoe Lateral route to TCO, its former affiliate. PSU contracts for the majority of its gas supply deliveries to the University Park campus through Dominion and has done so since 2014.

III. COLUMBIA'S REQUEST OF $98.3 MILLION

Q. WHEN DID COLUMBIA LAST INCREASE ITS BASE RATES?

A. The Final Order in Columbia's most recent base rate case (Docket R-2020-3018835) was entered on February 19, 2021. The Company was awarded an increase of $63,548,905. It had requested $100.4 million. Columbia has increased its base rates frequently during the past decade as shown in this table which indicates the amount it filed for and the result of the settlements in each case.

Table 1: Columbia Rate filings

Docket No.	Test Year Ending	Proposed Increase ($Millions)	Ordered ($Millions)	%
R-2008-2011621	Sep-08	$58.9	$41.7	70.8%
R-2009-2149262	Sep-10	$32.3	$12.0	37.2%
R-2010-2215623	Sep-11	$37.8	$17.0	45.0%
R-2012-2321748	Jun-14	$77.3	$55.2	71.4%
R-2014-2406274	Dec-15	$54.1	$32.5	60.1%
R-2015-2469665	Dec-16	$46.0	$27.1	58.9%
R-2016-2529660	Dec-17	$55.3	$35.0	63.3%
R-2018-2647577	Dec-19	$46.9	$26.0	55.4%
R-2020-3018835	Nov-20	$100.4	$63.5	63.1%

Prior to the filing in 2008, Columbia had not filed a base rate case since 1995. Now it is back for yet another proposed increase of $98.3 million.

Q. WHAT OTHER MECHANISM WAS PUT INTO PLACE IN 2013 TO SUPPORT INFRASTRUCTURE DEVELOPMENT OF NATURAL GAS DISTRIBUTION COMPANIES?

A. On March 14, 2013, the Commission approved Columbia's Distribution System Improvement Charge ("DSIC") which allows Columbia to recover reasonable and prudent costs incurred to repair, improve, or replace certain eligible distribution property that is part of the utility's distribution system. Columbia was the initiator of the DSIC filing at Docket No. P-2012-2338282. It claimed that if a DSIC were in place there would be a reduced need to file base rate cases.

Q. WHAT IS THE CAP OF COLUMBIA'S DSIC RIDER?

A. The DSIC is capped at 5.0% of distribution service revenues.

Q. USING COLUMBIA'S DSIC CAP OF 5.0% OF TOTAL REVENUES, WHAT COULD THE DSIC AMOUNT BE?

A. In Columbia's Exhibit 103, Sch 8, P. 1, the proposed distribution (non-gas) revenues are stated at $564,684,366. In this case the DSIC amount would be $28.3 million. The revenue increase proposed in this case is $98.3 million. While I cannot predict the outcome of this proceeding and do not know what the final revenue increase will be, it would be highly unlikely that it will be the entire request, and much more likely that it will be a fraction of that. Having a DSIC provides Columbia the ability to receive revenue of a similar magnitude as what it may receive in this case.

Q. WHAT OPERATING EXPENSES SHOULD BE REDUCED IF THE COMPANY IMPROVED ITS DISTRIBUTION SYSTEM?

A. One could reasonably expect that significant capital investment in Columbia's infrastructure would produce numerous improvements such as reduced gas losses due to leaks, better gas control, reduced labor and maintenance costs and other benefits that should be reflected through pro forma adjustments to its expense claims. Unfortunately, the overall operation and maintenance expenses filed in this case are increased significantly from the most recent 2020 case and those pro forma reductions do not appear.

Q. SHOULD COLUMBIA BE ABLE TO ATTRACT LOWER CAPITAL COSTS AS A RESULT OF THE AVAILABILITY OF ITS DSIC?

A. Yes. A utility whose rate structure includes a DSIC is able to recover the cost of capital investment continuously instead of waiting for a base rate filing that would include the cost of new investment in the utilities rate base. The ability to recover capital costs is beneficial to the utility and should lead to lower costs. Columbia's Ms. Krajovic testified in its DSIC filing at Docket P-2012-2338282 that "While infrastructure replacement will result in rate increases for Columbia's customers, the availability of the DSIC will enable the Company to attract lower cost capital" (Statement No. 1, 3:6-8). In the current proceeding, Mr. Moul, the Company's outside consultant for rate of return issues, testified that "The cost of capital for CPA, however, is not affected by the DSIC" (Statement No. 8, 8:11) and claims that because other natural gas companies are undertaking infrastructure rehabilitation mechanisms, the lower cost of capital promised by Ms. Krajovic is already accounted for. Natural gas utilities have been conducting infrastructure replacement of steel pipe for decades and Mr. Moul's contention that the benefit of the DSIC should be ignored is not credible. His efforts to increase the Company's rate of return from the forecasted 5.18% overall rate of return stated in its filing (Statement No. 1, 21:19-20) should be rejected.

IV. <u>COST OF SERVICE STUDY</u>

Q. WHAT IS A COST OF SERVICE STUDY?

A. A Cost of Service Study ("COSS") examines costs incurred by the utility and allocates those costs into distinct customer classes. To produce an accurate COSS it is necessary to possess quality accounting data detailing utility expenses and be able to determine assignment of expenses to customer classes. Expenses must be examined in detail to determine what customer or class of customers created the need for the utility to make the expenditure. This identification of expense responsibility is known as cost causation. In Columbia's 2020 case the Final Order defined the COSS as "a benchmark for evaluating customer class cost responsibility with the fundamental purpose of aiding in the accurate and reasonable design of rates by identifying all the capital and operating costs incurred by the utility in serving its customers, and then directly assigning or allocating these costs to each individual rate class ***based on established principles of cost-causation***." (emphasis added). It is critical that the Commission recognized that the COSS must be based on cost causation.

Q. WHAT IS COST CAUSATION?

A. This fundamental principle of ratemaking assigns costs to those classes of customers that are responsible for the incurrences of costs. The Commission has been consistent in its policy that considers cost causation as a fundamental principle and the bedrock of cost assignment in the ratemaking process. Failure to adhere to proper cost causation will create mis-allocations of cost which result in cross-class subsidization. This principle may not be violated just because some customers do not like bearing the costs or want to lessen the impact of the cost of the benefits they receive at the expense of others, nor may it be violated because a utility wishes to benefit one customer class at the expense of another. In the landmark case *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth. 2004) the Commonwealth Court declared cost of service as the "polestar" of ratemaking, and directed the Commission to set non-discriminatory reasonable rates.

Q. WHAT ARE THE COST CLASSIFICATION CATORGIES USED IN A COST OF SERVICE STUDY?

A. Costs are classified as demand related, energy or commodity related, or customer related. It is critical in cost of service studies to accurately determine cost causation by identifying the primary causative factor. In some cases there is only one causative factor.

Q. WHAT EXPENSES ARE DEMAND DRIVEN?

A. Demand costs vary and are dependent on the peak or maximum throughput. Engineering planning will examine the peak design day and base engineering designs on meeting throughput demands on that day. Components of the distribution system that are demand driven are gas mains, and the related operation and maintenance expense. This is the major component of rate base. Company witness Mr. Notestone stated, "Mains and services account for the majority of the Company's gross plant investment and distribution O&M expenses, excluding gas costs." (Statement No. 11, 9:14-15)

Q. WHAT EXPENSES ARE ENERGY DRIVEN?

A. The largest energy cost (also known as commodity or average demand cost) is the cost of purchased gas. The cost of purchased gas is not under consideration in this rate case as this is a base rate proceeding and we are considering the non-gas revenues of the Company. Other non-gas costs that are energy driven would be variable operation and maintenance expenses that can be identified as related to throughput. An example of this would be the O&M cost of a natural gas compressor. Such a piece of equipment would experience higher operating hours with greater throughput and incur correspondingly higher O&M expenses, similar to an automobile. If the car has been parked in the garage mostly since an owner has been working from home the maintenance needs (oil changes, filter, belts, brake pads, tires) have been less than when the car was driven for a daily commute to the office.

Q. WHAT EXPENSES ARE CUSTOMER DRIVEN?

A. Expenses that vary directly with the number of customers would be meters and services, customer contact centers, billing systems and a portion of distribution mains. Each customer has a gas meter. Of course, the small residential meter may cost less than a larger industrial meter but the meter costs are clearly customer driven. Customer contact centers need to be sized appropriately to manage the volume of daily calls, and they must grow as the number of customers increases. The size of the customer in terms of demand or volume does not make an impact on the number of calls to the call center. The billing system produce bills for Columbia's 438,111 customers. (source: Exhibit No. 3, page 1) Again, size in terms of demand or volume does not matter as all customer bills are calculated, printed or imaged, and mailed or emailed.

Q. IS THERE A CUSTOMER COMPONENT OF MAINS AND DISTRIBUTION SYSTEMS?

A. Yes. Mr. Notestone included a customer component in his allocation of gas mains cost for his COSS. Gas piping systems through neighborhoods obviously must be designed to reach from customer to customer so are partially customer-based, along with being demand based.

Q. WHAT COST OF SERVICE STUDIES DID THE COMPANY UNDERTAKE?

A. Company witness Mr. Notestone (Statement No. 11) explained that as in past base rate cases the Company conducted two COSS and then produced an average of the two, so three studies in all. The two studies, known as the customer-demand study and the peak & average study, allocate the cost of mains differently. Mr. Notestone also produced the average study. In prior rate cases including the recent 2020 case he used the average study as the primary guide for allocation of the revenue increase, but he did not use the average study in this rate case. Instead he used the peak & average COSS.

Q. WHY DID THE COMPANY USE THE PEAK & AVERAGE COSS IN THIS RATE PROCEEDING?

A. The only reason Mr. Notestone stated was, "Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case." *Id* 3:17-19. Mr. Notestone abandoned the Company's long practice of using the average study, not because use of the peak & average study was a more accurate reflection of cost causation, but only because the Commission, in one recent case, expressed a preference for the Peak & Average study due to "errors"[1] in the other Customer-Demand study. I will examine that in more detail and review the recommended decision and final order in the recent 2020 rate case of Columbia.

Q. WHAT WAS THE ALJ's RECOMMENDATION IN COLUMBIA'S 2020 BASE RATE CASE?

A. In her decision ALJ Dunderdale stated, "The ALJ recommends the Commission use the Peak & Average COSS, as promoted by OCA, in this base rate proceeding. ***Columbia Gas' Customer Demand COSS would be the preferred method***, but it contains serious flaws that skews its reliability and makes it unsuitable for use at this time and with this NGDC." RD at 394 (emphasis added).

Q. DID COLUMBIA MAKE THE SAME "ERRORS" IN THE CUSTOMER/DEMAND COSS IN THIS PROCEEDING?

A. No. The "errors" that were referred to stem from an argument advanced by OCA Witness Mr. Mierzwa that Mr. Notestone should not have separated gas main investment by operating pressure. The Commission stated:

> Mr. Mierzwa argued that the Company's separation of mains investment by operating pressure should be removed, primarily due to its use of original cost instead of net investment in the development of its allocation factors for each of the distribution mains categories. More specifically, Mr. Mierzwa challenged the Company's separation of mains by pressure group in the study because the allocation uses original cost and not net investment. Mr. Mierzwa asserted that the

[1] Mr. Notestone did not make computational mistakes in the Customer-Demand study but OCA's Mr. Mierzwa opined that a different methodology of treatment of mains investment was appropriate and that Mr. Notestone's method was an error.

> separation of pressure groups based on gross plant investment does not take into account the age of the pipe, and low-pressure pipe is generally older and, therefore, more depreciated than regulated pressure pipe. Mr. Mierzwa contended that because 53% of the low-pressure system is constructed of steel, and because steel pipe is generally older and, therefore, more depreciated than plastic pipe, customers served off low pressure pipe should be assigned less net investment than regulated pressure customers.

(Final Order at 194). In this proceeding Columbia's Mr. Notestone did not separate mains by pressure. He testifies:

> **Q. Have you again performed a detailed analysis of each of Columbia's low pressure and higher pressure systems in this case?**
> A. No. Mains cost allocation factors produced from the separation of mains by pressure study are not materially different than the mains allocators produced from simply using total mains (i.e. no separation of mains by operating pressure). This is largely due to Columbia's pipe replacement efforts over the last several years which have had the effect of phasing out its low pressure mains. Columbia's low pressure mains are typically older and constructed of cast iron or steel pipe. Over time, Columbia has been replacing this low pressure pipe with plastic pipe operated under higher pressures. Therefore, the results produced from the separated mains pressure study have become less meaningful as the system has become more homogenous in terms of operating pressure.

(Columbia Gas Statement No. 11, 8:3-14).

Mr. Notestone removed the "error" that swayed the ALJ to choose the Peak & Average COSS over the Customer-Demand COSS, even though she stated that "Columbia Gas' Customer Demand COSS would be the preferred method."

Q. WHAT DID THE COMMISSION STATE IN ITS FINAL ORDER IN COLUMBIA'S 2020 BASE RATE CASE?

A. "(W)e are not persuaded to reverse the ALJ's Recommended Decision that adopted the OCA's P&A ACCOSS and methodology in this proceeding." Final Order at 211. Since the ALJ's Recommended Decision stated that the Customer-Demand COSS would be the preferred method were it not for errors, and therefore she recommended use of the Peak &

Average COSS, which we can think of as the runner-up in this competition, having come out on top only because the best COSS contained some errors. That is not the case in this proceeding.

Q. WHY SHOULD THE CUSTOMER DEMAND COSS BE THE PREFERRED METHOD FOR COST ALLOCATION AS STATED IN THE 2020 COLUMBIA RATE CASE RECOMMENDED DECISION?

A. It is important to make decisions based on facts and engineering. Since the key issue in selecting a COSS is the treatment of expenses on gas mains, and we know that gas mains and their maintenance costs are the largest component of the rate base and operating expenses, it is critical that the process to plan, design, and construct gas mains be the basis of the COSS. Therefore, I reviewed the responses to several data requests investigating the actual engineering process to determine the design of the distribution system and the sizing of the gas mains.

Q. HOW DOES THE COMPANY DETERMINE THE ENGINEERING REQUIREMENTS NECESSARY FOR THE INSTALLATION OF GAS MAINS?

A. I reviewed the responses to several data requests about this subject, which I have included as Exhibit PSU-1. The critical and significant data collected by the Company is the total BTU/hr connected load. See Exhibit PSU-1, response to PSU 1-002, PSU 1-006, PSU 2-001. In its response to PSU 1-001 Columbia stated:

> In general, sizing mainlines within our distribution systems is based upon many factors. They include: the MAOP (maximum allowable operating pressure), the normal operating pressure, the minimum operating pressure (under peak conditions), the delivery pressure requested on behalf the

> customer, the length of main, and of course load information (typically in terms of Mcfh - 1000 cubic foot per hour).

When asked about meter and service line sizing in response to PSU 1-006 Columbia stated:

> The connected load of a customer moving into an existing facility would be based upon the total rating (either in BTUs - British Thermal Units, or cubic feet of gas per hour) of the gas appliances to be used by the customer. This information is provided to Columbia of PA, Inc., by the customer.
> Once the load information has been determined, the service line would be sized based upon the factors identified in the response to PSU 1-001.

PSU Exhibit 1 at p. 2. When asked to provide more definition to the term "total BTU load" in response to PSU 2-001, Columbia clarified it was not referring to annual throughput or annual load but instead the demand of the customer:

> total BTU load is the total connected load based on the sum of the BTU/hr input ratings of every gas-burning appliance. The BTU/hr input ratings can be found stamped onto the equipment itself and/or in the literature associated with the appliance.

PSU Exhibit 1 at p. 3. None of the data used for pipe sizing and distribution system planning, engineering, and construction include annual commodity usage. Repeatedly Columbia asserts it considers the demand load information, expressed in terms of BTU/hr. The Company collects this BTU/hr data through its web-based tool or through customer interviews. My review of the Company's data request responses, including the Company manuals and procedures have identified that connected load, along with delivery pressure and length of pipe necessary to attach to the customer are the only data used in gas main design and sizing.

The process that Columbia uses is similar to the process that I am familiar with during my twenty-plus years working for natural gas distribution companies. As Director of Residential and Commercial Marketing for Peoples Gas, and Vice President of Marketing for Citizens Utilities, I regularly reviewed new gas main line project documents that contained engineering data to determine line sizes, and as a Registered Professional Engineer I am familiar with the process that the facilities design engineer goes through in pipeline design.

Q. IS ANNUAL ENERGY CONSUMPTION CONSIDERED IN THE ENGINEERING DESIGN OF GAS MAINS?

A. No. The annual throughput, or annual load, or in COSS jargon the "average demand" is not used in the design and determination of gas main piping. Instead, the cost causer of gas mains is the demand, not the commodity use, of the customer. All sizing of pipe (the pipe diameter, and subsequent system operating pressure) is determined by the demand, which is based on connected load in BTU/hr.

Q. WHAT COST OF SERVICE STUDY IS BASED ON COST CAUSATION OF GAS MAINS INSTALLATION AND OPERATION?

A. The cost of service study that is based on cost causation is the Customer-Demand study as conducted by Columbia. It properly determines the allocation of gas main piping costs based on how the piping system was designed using the connected demand. The Peak and Average method used in the other COSS conducted by the Company does not apply cost causation accurately because it allocates the costs of gas mains based in large part to the average demand or annual throughput and that is a violation of cost causation principles. Such allocations result in cost-shifting and cross-class subsidization which must be avoided and is not good ratemaking. The Peak & Average COSS prepared by Mr. Notestone must be rejected and the allocation of revenue that Mr. Notestone presented based on that COSS must also be rejected. In its place should be the Customer-Demand COSS that was also prepared by Mr. Notestone, along with the allocation that is determined using the Customer-Demand COSS.

The average COSS and the allocation of revenue based on the average COSS must also be rejected for it averages the results of two studies, and I have already identified the violation of cost causation principles that are inherent in the Peak & Average COSS.

Q. WHAT IS THE SUMMARY OF YOUR TESTIMONY?

A. To ensure that the correct cost allocation of the revenue requirement is based on cost causation, the allocations based on the Customer-Demand COSS presented by the Company must be used. Mr. Notestone's recommendation of allocating revenue using a study that does not adhere to cost causation principles must be rejected.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JAMES L. CRIST

PRESIDENT, LUMEN GROUP, INC.

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Phone: 412.487.9708 ● Cell: 412.613.8886 ● E-mail: JLCrist@aol.com

DEMONSTRATED AREAS OF EXPERTISE

¨ GENERAL MANAGEMENT	Proven executive-level management expertise with excellent capabilities in developing, implementing, and supervising corporate-wide policies and procedures in areas including sales, marketing, customer service, public relations, rates, regulatory affairs, and administration. Possess a unique combination of abilities to set goals, develop winning business strategies, organize structures and work methods, and train the right people for the right positions to make it all work. Skilled in strategic short and long-term planning and budgeting with effective abilities in reducing the "fat" and increasing organizational efficiency. A creative, decisive leader who can successfully meet challenges and overcome obstacles to achieve profit objectives.
¨ REGULATORY STRATEGY	A thorough strategist with an extensive background in utility business unit operation (electric, natural gas, water/wastewater) the full range of rate and regulatory functions, from tariff development and special contract negotiation. Proven personal testifying skills with an outstanding record of developing and presenting successful written and oral testimony, along with settlement negotiations.
¨ PERSONNEL MANAGEMENT	Effective interpersonal communications skills support outstanding capabilities in recruiting, training, motivating, and directing staff at all levels. Proven ability to build productive, highly motivated teams of sales/marketing, operations, technical, and customer service personnel who contribute to top organizational performance.
¨ PERSONAL ATTRIBUTES	A determined, hardworking, challenge-driven executive with the skills and experience to bring excellence to any business organization. A high-energy mover and shaper ... experienced in successful start-ups and turn-arounds. An excellent communicator - written and verbal. A frequent speaker at professional symposiums, able to interpret and communicate complex concepts for diverse audiences. An engineering/technical specialist and a management generalist. Active in civic and community affairs.

EMPLOYMENT HISTORY

LUMEN GROUP, INC., Pittsburgh, PA — 1996 - Present

President - A consulting practice specializing in strategic planning, business planning, regulatory strategy, marketing and venture development in the electric, natural gas and energy services industries. Please see Addendum for amplification of consulting assignments.

ACN ENERGY, Farmington Hills, MI — 2004-2005

Vice President, Consumer Markets

OPTIRON, Pittsburgh, PA — 2003-2004

Vice President, Marketing

E R I SERVICES, Pittsburgh, PA — 1996

Vice President, Marketing & Product Development

CITIZENS UTILITIES, Harvey, LA & Stamford, CT — 1994 - 1995

Vice President, Marketing

CONSOLIDATED NATURAL GAS, Pittsburgh, PA — 1977 - 1994

Director, Residential & Commercial Marketing (1988 - 1994)
Manager, Technical Sales/Market Development (1985 - 1988)
Market Development Specialist (1982 - 1985)
Project Engineer (1979 - 1982) ... promoted from ... **Process Engineer** (1977 - 1979)

OCCIDENTIAL CHEMICAL CORP., Niagara Falls, NY — 1975 - 1977

Research Engineer

PENNSYLVANIA STATE UNIVERSITY, State College, PA — 1988
CLEVELAND STATE UNIVERSITY, Cleveland, OH — 1984

Instructor (Evening Division) - Economics, Engineering Economics

SELECTED ACCOMPLISHMENTS

VICE PRESIDENT, CONSUMER MARKETS - ACN ENERGY

Retained for a turnaround assignment with an independent energy marketing company. Participated on the executive management team and directed a decentralized 3-person market management staff responsible for sales to 85,000 customers. Worked directly with the parent company executives and business unit management to create market-driven strategies for the corporation. Sharpened marketing and sales efforts of an energy marketing company operating in seven states and packaged company for eventual sale to Commerce Energy.

- Primary executive responsible for sales. Directed a team of market managers that was responsible for all aspects of 11 different markets (electric and natural gas) around the country. Provided direction and support to sales channel organization of commissioned representatives. Turned around five-year annual loss to significant gain in 2004. Tightened focus on market decisions.
- Directed regulatory involvement to insure compliance with market rules. Focused on maintaining positive relationships with state utility regulators to avoid penalties.
- Led weekly operations meetings during absence of COO. This involved direction of call center, provisioning, billing, credit & collection, and marketing.
- Worked in a team setting with other executives (VP Finance, VP Supply, COO) to provide consistent, professional focus to workforce experiencing changing environment.
- Directed development of annual business plan and budget with targets resulting in both goal achievements and income improvements.
- During transition period working with merger partner Commerce Energy's executive team to train and advise incoming executives.
- Directed customer service improvements in the customer acquisition process which resulting in replacing outdated paper/fax process with phone order process.
- Organized and directed trade show presence at national sales convention for alliance sales channel to create awareness of new product and market focus.

VICE PRESIDENT, MARKETING - OPTIRON

Retained as part of executive team in venture capital startup company developing new CIS/CRM software for the energy industry. Worked closely with CEO, COO, and Director of Sales to determine business strategy and develop marketing strategy to create market awareness and brand attributes in medium and small energy companies.

- Added in-house marketing communications function and personnel and revamped all marketing materials.
- Added new website functionality and content.
- Implemented first print advertising campaign in industry publications.
- Using industry contacts, positioned Option as expert presenter at several conferences and trade shows.
- Developed business plan to identify sales prospects and created competitive database of CIS/CRM vendors.
- Participated in development of exit strategy plan resulting in the successful sale to large software company.

VICE PRESIDENT, MARKETING & PRODUCT DEVELOPMENT - ERI Services

Assumed responsibility for creating a new corporate marketing vision and strategy to facilitate entry into new deregulated energy markets nationally.

- Recruited and selected an exceptional management team and integrated marketing and sales activities into one functional operating unit.
- Established the product innovation process to identify and create new and profitable market-driven service offerings.
- Directed strategic branding to launch the new corporate identity; managed a $2 million national advertising campaign; and developed over $1 million of new sales/marketing collateral materials.
- Instituted financial controls that reduced costs 60% in the Iowa market rollout while maintaining 80% market share and high customer satisfaction.

VICE PRESIDENT, MARKETING - Citizens Utilities

Directed a decentralized 20-person sales staff and a five person marketing staff. Worked directly with the Board of Directors, Corporate President, and Sector Vice President to create market-driven sales strategies for the corporation. Revamped and redirected sales efforts of a five-state energy utility with 440,000 customers.

- Increased industrial sales revenues by reorganizing unregulated gas marketing effort.
- Revamped merchandising utilizing inbound telemarketing in Louisiana Gas.
- Revised training programs for entire sales force, identifying and correcting missing technical and equipment training, adding a greater competency in the commercial and industrial sectors.
- Developed first business plan in sales and marketing organization with monthly budget monitoring and

targets resulting in both goal achievements and cost improvements.

- Launched an aggressive direct marketing program that increased sales 500% over previous year.
- Increased share of gas transportation business in Arizona by 15% in first year of operation through marketing efforts.
- Created a telephone long distance business in Louisiana that captured a 20% share (2nd to AT & T).

DIRECTOR, RESIDENTIAL & COMMERCIAL MARKETING - Consolidated Natural Gas

Managed a marketing staff of 12 and a "dotted-line" 24-person field sales force. Directed marketing and sales efforts in consumer, business, and manufacturing markets with $154 million revenue.

- Added $6 million in revenue by developing new products in gas transportation, supply, and agency.
- Directed sales activities in residential, commercial, institutional and governmental accounts for both product sales and technology sales.
- Produced $600,000 annual revenue and doubled competitive project wins by revamping market approaches to residential and commercial new construction.
- Secured 50% increase in customer decisions over 5 gas companies and 4 electric companies.
- Experienced in PUC and Legislature lobbying. Increased revenues $2.3 million through regulatory strategy/testifying and received major competitive program approval.

MANAGER, TECHNICAL SALES / MARKET DEVELOPMENT - Consolidated Natural Gas

Directed new market development and competitive market support.

- Focused on commercial and industrial accounts and increased the depth of relationship beyond the typical utility provider of service to a rich full service information provider and business partner.
- Captured $150,000 in new business annually by competitive pricing analysis, sales tool development, and market approach.
- Developed total advertising and promotional plan launching new market programs.
- Compiled extensive technical database and developed economic model for project analysis, eliminating a $100,000 operating budget expense.
- Led statewide coalition with customers and government agencies for fair treatment of new technology.

EDUCATION - PROFESSIONAL

UNIVERSITY OF PITTSBURGH, Pittsburgh, PA 1982

M.B.A. Degree

CARNEGIE - MELLON UNIVERSITY, Pittsburgh, PA 1975

B.S. Degree in Chemical Engineering

Registered Professional Engineer AGA Hall of Fame, 4/1991

JAMES L. CRIST

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Suite 101, 4226 Yarmouth Drive ● Allison Park, PA 15101
Phone: 412.487.9708 ●Cell: 412.613.8886 ●E-mail: JLCrist@AOL.com

AMPLIFICATION OF LUMEN GROUP CONSULTING ASSIGNMENTS

A consulting practice specializing in strategic planning, business planning, marketing and venture development in the telecommunications, energy, and services industries.

REGULATORY

Represented the National Energy Marketers Association and their members in Equitable-Dominion Peoples merger case. Developed strategy, presented written and oral testimony and negotiated on behalf of clients. Worked with other interveners and FTC on anti-competitive issues.

UTILITY RATE NEGOTIATION

Represented large client group seeking to obtain rate reduction from electric utility. Prepared strategy, wrote testimony, and exceeded expectations by achieving a 40% reduction in charges, producing a $2 million annual reduction.

STRATEGIC PLANNING FOR ON-SITE POWER GENERATION

Participated in proposal development for a 27-MW power plant on Kauai. Handled critical customer needs assessment in rapid turnaround fashion to meet proposal deadline. Maintained relationships with clients, vendors and proposal partners. Our proposal was selected as the preferred bidder out of five strong competitors.

NEW BUSINESS START-UP / TARIFF NEGOTIATIONS

Participated in the development of a new gas distribution utility in New York. Handled tariff development, pricing structure, transportation contracting, and operations, maintenance, and emergency manual preparation.

SALES STRATEGY/BUSINESS DEVELOPMENT

Developed sales strategy to focus on profitable accounts and markets. Developed sales training and account management plans and provided consulting to energy marketing organizations to improve overall sales.

BUSINESS STRATEGY/BUSINESS DEVELOPMENT

Developed business strategy to verticalize eCommerce/Customer Relationship Management product for the energy/utility industry. Produced sales training for global applications, product promotion presentations, developed alliance relationships with system integrators and software partners, developed business. Client is market leader in North America.

JOINT VENTURE/PRODUCT DEVELOPMENT

Assembled joint ventures resulting in sales to offer new hedge-based weather risk management retail product. Identified venture partners, and developed business arrangements and closed million-dollar deals

ENERGY PROCUREMENT

Served as energy expert on project team that obtained long-term natural gas supply for major government facilities. Prepared project specifications, negotiated with suppliers, prepared RFP, negotiated major reduction in delivery charges. This project resulted in annual cost reduction of $2.5 million.

NEW BUSINESS DEVELOPMENT - TELECOMMUNICATIONS

Analyzed use of electric utility assets for possible telecommunications business venture. Wrote the business plan that identifies regulatory and non-regulatory issues, marketing plans, financial analysis, and organizational requirements. Launched the new non-regulated business unit in 1996.

JOINT VENTURE DEVELOPMENT - TELECOMMUNICATIONS

Conducted analysis of potential joint venture partners for new unregulated telecommunications venture, bypassing the Bell operating company. Held screening discussions with potential partners and selected lead candidate for venture. Developed working agreement with partners along with business case to launch venture.

JOINT VENTURE DEVELOPMENT - TELECOMMUNICATIONS & ENERGY

Developed strategic plan for joint venture involving gas, electric, and telecommunications partners. Screened potential business partners and held discussions with lead candidates. Assembled justification for top management approval.

PRODUCT DEVELOPMENT - UNREGULATED ENERGY SERVICES

Developed energy products for start-up subsidiary of major energy utility. Identified potential products and selected most likely candidates for further development. Developed market plans and sales plans for products.

MARKET PLAN - DIRECT MARKETING

Developed the market plan for large, global direct marketing agency to enter the energy industry. Identified strategies, strengths, weaknesses, and target prospects. Initiated sales effort and developed new business.

CORPORATE IMAGE DEVELOPMENT

Developed complete business unit identity for a new operations and services company. Produced capabilities brochure for use with prospects.

MARKET RESEARCH

Conducted market research to identify new customer/new business opportunities for major energy utility. Comprehensive project with two additional similar projects were completed. Entailed determination of goals, development of research methodology, script preparation, vendor selection, data analysis, and development of action plan.

MARKET DEVELOPMENT

Organized intervener group in Illinois consisting of retail marketers and intervened in three rate proceedings (Nicor Gas base case, WPS-Peoples merger case, Peoples Gas base case) and secured significant improvements in rules and procedures enabling marketers to increase their business and profitability. Developed strategy and presented written and oral testimony.

PARTIAL LIST OF REGULATORY EXPERIENCE OF JAMES L. CRIST

1. Dominion Energy Ohio Motion, Case No. 18-1419-GA-EXM, Representing Retail Energy Supply Association
2. Aqua America/Peoples Natural Gas Merger, Docket R-2018-3006061, Representing Natural Gas Supplier Parties and Retail Energy Supply Association
3. Peoples Natural Gas General Base Rate Increase, Docket R-2018-3006818, Representing Peoples Industrial Intervenors
4. Duquesne Light Company General Base Rate Increase, Docket R-2018-3000124, Representing the Duquesne Industrial Intervenors
5. Columbia of PA General Base Rate Increase, Docket R-2018-2647577, Representing the Pennsylvania State University
6. West Penn Power Company, Default Service Program, Docket R-2017-2637866, Representing the Pennsylvania State University
7. Vectren Energy Delivery Ohio, Alternative Rate Plan, Case No. 18-0049-GA-ALT, Representing Retail Energy Supply Association
8. Columbia of PA Gas Cost Increase, Docket R-2017-2591326, Representing the Pennsylvania State University
9. West Penn Power Company, General Base Rate Increase, Docket R-2016-2537359, Representing the Pennsylvania State University
10. Columbia of PA General Base Rate Increase, Docket R-2016-2529660, Representing the Pennsylvania State University
11. UGI Utilities General Base Rate Increase, Docket R-2015-2518438, Representing Dominion Retail, Inc., Shipley, Choice, LLC, Interstate Gas Supply, Inc., Amerigreen Energy, and Rhoads Energy
12. Columbia of PA General Base Rate Increase, Docket R-2015-2468056, Representing the Pennsylvania State University
13. West Penn Power Company, General Base Rate Increase, Docket R-2014-2428742, Representing the Pennsylvania State University
14. Herman Oil & Gas Company, General Base Rate Increase, R-2014-2414379, Representing Herman Oil & Gas Company
15. Columbia of PA General Base Rate Increase, Docket R-2014-2406274, Representing the Pennsylvania State University
16. Ameren Gas- General Base Rate Increase, Docket No. 13-0192, Representing Dominion Retail and Interstate Gas Supply of Illinois
17. Columbia of PA General Base Rate Increase, Docket R-2012-2321748, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
18. Columbia of PA Petition for Approval of a Distribution System Improvement Charge Docket R-2012-2338282, Representing the Pennsylvania State University
19. PUC PA Generic Investigation Regarding Gas-On-Gas Competition, Docket No. P-2011-2277868, Representing the Pennsylvania State University
20. Ameren Gas- General Base Rate Increase, Docket 11-0282 (Cons.), Representing Dominion Retail and Interstate Gas Supply of Illinois
21. Water and Power Authority (USVI)- Electric Base Rate Case, Docket 575, June 2009, Representing Frenchman's Reef Marriott
22. Water and Power Authority (USVI)- Water Base Rate Case, Docket 576, June 2009, Representing Frenchman's Reef Marriott
23. Public Service of New Mexico 2010 Base Rate Case, Informal rate design workshops pursuant to the stipulation in NMPRC Case No. 08-00273-UT, Representing City of Albuquerque
24. Public Service of New Mexico, Electric base case at Case No. 08-00273-UT, Representing City of Albuquerque
25. Public Service of New Mexico 2009 Renewable Energy Procurement Plan for 2010, Case No. 09-00260-UT, Representing City of Albuquerque and Santa Fe County
26. Public Service of New Mexico, Gas sale case at Case No. 08-00078-UT, Representing City of Albuquerque
27. UGI Utilities, Central Penn Gas, Penn Natural Gas, Gas Cost Increase, Docket No. R-2011-2238953, Representing Shipley Energy, Rhodes Energy, and CenterPoint Energy
28. UGI Utilities- Gas Division, Gas Cost Increase, Docket No. R-2010-2172933, Representing Shipley Energy
29. Columbia of PA General Base Rate Increase, Docket R-2010-2215623, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
30. Columbia of PA General Base Rate Increase, Docket R-2009-2149262, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
31. Columbia of PA General Base Rate Increase, Docket R-2008-2011621, Representing Hess Energy, Dominion Retail, Interstate Gas Supply, and Shipley Energy
32. Columbia of PA Gas Cost Increase, Docket R-2008-2028039, Representing Dominion Retail, Interstate Gas Supply, and Shipley Energy
33. PPL Electric Utilities Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge, Docket No. P-2009-2129502

34. Nicor Gas Company, Provision of facilities and services and the transfer of assets between Nicor Gas Company and Nicor Inc., Docket No. 09-0301, Representing Dominion Retail
35. North Shore Gas and Peoples Gas Light and Coke Company, General Base Rate Increase, Dockets 09-0166 and 09-0167, Representing Dominion Retail, Interstate Gas Supply and Nicor Advanced Energy
36. Nicor Gas Company, Base Rate Increase, Docket No. 08-0363, Representing Interstate Gas Supply and Dominion Retail
37. North Shore Gas and Peoples Gas Light and Coke Company, General Base Rate Increase, Dockets 07-0241 and 07-0242, Representing Dominion Retail, Interstate Gas Supply and U.S. Energy Savings
38. WPS Resources, Peoples Energy, Peoples Gas Light and Coke Company, North Shore Gas Company, Application pursuant to Section 7-204 of the Public Utilities Act for authority to engage in a Reorganization, Docket 06-0540, Representing Dominion Retail, Interstate Gas Supply, US Energy Savings, MxEnergy, and Direct Energy Services.
39. Allegheny Energy, Approval of Retail Electric Default Service Program and Competitive Procurement Plan, Docket No. P-2008-2021608, Representing the Pennsylvania State University
40. Allegheny Energy, Generation Rate Cap, Docket No. P-2007-2001828, Representing the Pennsylvania State University
41. Equitable Gas Company, Rate Increase, Docket R-2008-2029325, Representing Independent Oil & Gas Association and Hess Corp.
42. Equitable Gas Company and Peoples Gas, Merger Case, Docket A-122250F5000, Representing National Energy Marketers, Hess Corporation, and Constellation New Energy.

Exhibit PSU-1

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY
Set 1

Question No. PSU 1-001:

Provide documents or manuals used to determine sizing of distribution system piping in new construction. Explain any differences in procedures that depend on customer classification (residential, commercial, industrial)

Response:

In general, sizing mainlines within our distribution systems is based upon many factors. They include: the MAOP (maximum allowable operating pressure), the normal operating pressure, the minimum operating pressure (under peak conditions), the delivery pressure requested on behalf the customer, the length of main, and of course load information (typically in terms of Mcfh - 1000 cubic foot per hour).

Columbia Gas of PA, Inc., will determine the size mainline to be utilized based on flow guidelines provided per our Gas Standards. See HIGHLY CONFIDENTIAL Attachment A to this response. There are different criteria used dependent on the pressure range of our operating systems, to minimize pressure drop, so we can meet the new load demand, as well as the demands of our current customers. Columbia will also determine if the main should be comprised of medium density, high density, or steel, depending on the MAOP or capacity needed.

Also, Synergi, Columbia's software modeling software (which models our systems) is used to confirm recommendations of sizing mainlines, to help ensure safe and reliable service to all our customers.

These same processes and procedures apply to residential, commercial, and industrial accounts.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY
Set 1

Question No. PSU 1-006:

Explain the process of determining the connected load used when initiating service with a commercial customer moving into an existing facility. Explain once connected load is determined how that is considered in the determination of meter size, and service line size.

Response:

The connected load of a customer moving into an existing facility would be based upon the total rating (either in BTUs - British Thermal Units, or cubic feet of gas per hour) of the gas appliances to be used by the customer. This information is provided to Columbia of PA, Inc., by the customer.

Once the load information has been determined, the service line would be sized based upon the factors identified in the response to PSU 1-001.

In general, sizing the meter would utilize the same factors as listed above, with the exception of length. Per the manufacturer's specifications of what meters Columbia use, the meter would be sized accordingly based upon the pressure going through the meter to accurately measure the load requested by the customer.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2021 RATE CASE PROCEEDING

Docket No. R-2021-3024296
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY
Set 2

Question No. PSU 2-001:

Regarding the response to PSU Set I-2, does the phrase "total BTU load" mean total connected load based on the sum of the BTU/hr ratings of every gas-burning appliance? If not, please explain. What does a customer have to do to obtain such information?

Response:

Yes, total BTU load is the total connected load based on the sum of the BTU/hr input ratings of every gas-burning appliance. The BTU/hr input ratings can be found stamped onto the equipment itself and/or in the literature associated with the appliance. In many cases, the manufacturers also include the information on their websites.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2021-3024296
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

PSU Statement No. 1-R

REBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

Dated: July 14, 2021

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. I previously presented direct testimony and now I am presenting rebuttal testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU" or the "University").

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS REBUTTAL TESTIMONY?

A. Specifically, in my rebuttal testimony I will review several allocated cost of service study ("ACOS") recommendations made by OCA witness Mr. Mierzwa, I&E witness Mr. Cline, and OSBA witness Mr. Knecht. Because their views are not based on cost causation, they skew the revenue responsibility, which is unacceptable. I will provide evidence why the Peak & Average ACOS that they prefer, which is not based on cost causation, should not be used and that the Customer-Demand Cost of Service Study performed by the Company, which is based on cost causation, is valid and should be utilized to allocate any increase granted by the Commission.

Q. WHAT ACOS DID THE COMPANY USE TO DETERMINE THE REVENUE RESPONSIBILITY OF THE CUSTOMER CLASSES?

A. Company witness Mr. Nodestone explained, "For this case, Columbia used the peak and average study as the primary study to establish class rates of return at present and proposed rates." Statement No. 11, 16:18-20. The Peak & Average ACOS is the methodology that favors the residential class heavily, and the Company used those study results to determine revenue allocations. This is a departure from the Company's practice in the nine previous rate cases since 2008 where the Company used its Average ACOS as the basis for determining class rates of return and revenue allocation.

Q. WHAT ACOS DID OCA WITNESS MR. MIERZWA RECOMMEND?

A. Mr. Mierzwa recommended the use of the Company's Peak & Average ACOS. In his direct testimony he reviews the methodologies used in the three ACOSs conducted by the Company. He explains that the investment in distribution mains is allocated differently in two of the ACOSs. In the Customer-Demand ACOS, the cost of mains is allocated to the individual rate classes based on the number of customers in the rate class (the "customer" part of "customer-demand"), and also based on the design peak day demands of the customers in each rate class (the "demand" part of "customer-demand").

He then describes the Peak & Average method where main investment is allocated 50 percent based on the design peak day demands and 50 percent based on the annual demand, which is the same as total annual throughput. He also explained that the Company produced an Average ACOS, which is an average of the two studies.

Mr. Mierzwa continues his testimony explaining that the primary guide for the distribution of revenue was the Company's Peak & Average ACOS because of the Commission's decision at Docket No. R-2020-3018835. He states that he agrees with using the Peak & Average ACOS to determine revenue distribution.

Q. WHAT IS MR. MIERZWA'S OPINION OF THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. Mr. Mierzwa states that the revenue increase Columbia proposed for the LDS/LGSS customers and Flex customers is not enough and they should be increased more. Specifically, he wants to increase the LDS/LGSS group from $19.7 million to $26.9 million and wants to increase Flex customers by $15,790, according to his Table 3. Examination of Table 3 shows that Mr. Mierzwa's intention is to increase the LDS/LGSS along with the SDS/LGSS classes over 36%, while increasing the residential classes only 16.4%.

Q. WHAT IS MR. MIERZWA'S REASON FOR WANTING TO SHIFT ADDITIONAL REVENUE RESPONSIBILITY TO THE LDS/LGSS AND FLEX CUSTOMERS?

A. According to Mr. Mierzwa, the Peak & Average method results showed a relative rate of return at present rates for the LDS/LGSS customers of 0.17.

Q. WHAT CAUSED THE LOW RELATIVE RATE OF RETURN?

A. The total revenue requirement and the class allocation of revenues in the previous eight rate cases from 2008 through 2018 were determined through a settlement process that resulted in "black box" settlements. In such settlements the parties in the case, including the Company, reach agreement on the total revenue increase and how that increase will be allocated to the customer rate classes. It is not specified what ACOS was used or what class rates of return were calculated. The resulting class revenue allocations are included as part of the settlement recommendations submitted to the Administrative Law Judge and then incorporated into the ALJ's recommended decision and subsequently adopted and approved by the Commission. It is important to note that the parties that represent the interests of the different customer groups (residential, commercial, industrial, flex) all compromise and reach agreement through the give-and-take discussions of the settlement process. "It is the Commission's policy to encourage settlements. In most cases, the parties work diligently to find common grounds upon which to settle the case in whole or part."[1]

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[1] Pennsylvania Public Utility Commission A Guide To Utility Ratemaking, James H. Cawley & Norman J. Kennard (2018) P.47

In those eight previous rate cases the revenue allocations proposed by the Company in its filings were based on the results from the Average ACOS, then further determined by settlement discussions of all the parties. I have been involved in those discussions and found them to be productive and fair. Unlike those prior settlements, in the 2020 proceeding, the revenue requirement was fully litigated and, as I described in my direct testimony, the ALJ recommendation for the ACOS methodology was that the Peak & Average ACOS should be used due to some perceived flaws in the preferred method, the Customer-Demand ACOS.

It is to be expected that when comparing the class rates of return of the previous eight rate cases that were settled, with the result in this rate case of the Peak & Average ACOS, a method that greatly favors residential customers, that the LDS/LGSS would be shown to have a low relative rate of return. Mr. Mierzwa wants to "fix" that by moving additional revenue responsibility to the LDS/LGSS customers resulting in a 36% rate hike. This is unconscionable.

Q. IS THE CUSTOMER-DEMAND ACOS PROPOSED IN THIS CASE FREE OF ERRORS?

A. Yes. In 2020 the ALJ stated that Columbia Gas' Customer Demand COSS would be the preferred cost of service study method. Unfortunately, the ALJ found that the Customer Demand COSS in that particular case contained serious flaws that skewed its reliability and made it unsuitable for use at that time with Columbia. R.D at 394. Importantly, that was not a permanent prohibition of using the preferred Customer-Demand ACOS and the evidence I presented in my direct testimony proves that the Customer- Demand ACOS is the only method based on cost causation, the foundation of a cost of service study. I explained in my direct testimony that when he produced the current Customer-Demand ACOS Mr. Notestone did not separate gas mains by pressure, which removes the issue that swayed the ALJ to recommend that the 2020 Customer-Demand ACOS not be used. Supporting the accuracy of the current Customer-Demand ACOS, I note that none of the witnesses (Mr. Mierzwa, Mr. Cline, Mr. Knecht) cited any issues or concerns with Columbia's Customer-Demand study.

Q. IS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION JUST AND REASONABLE?

A. No. For the same reasoning I explained, you cannot take customer class revenue allocations that have been established in eight rate cases since 2008 by compromise settlements and force an extreme result from the Peak & Average ACOS onto customers and expect an increase that is not draconian. The Company's proposed increase for the LDS/LGSS customers was 29.9% compared to the increase proposed for residential customers of 18.6%. It is grossly unfair. Doing so without regard to what could be dire consequences to the businesses and institutions in the LDS/LGSS class who have faced the challenges of Covid impacts to business or operations and are still dealing with such disadvantageous business conditions.

Q. WHAT ACOS DID THE BUREAU OF INVESTIGATION AND ENFORCEMENT WITNESS MR. CLINE RECOMMEND?

A. Similar to Mr. Mierzwa in his direct testimony (I&E Statement No. 3) Mr. Cline explained that the Company conducted a customer-demand ACOS, a Peak & Average ACOS, and an Average ACOS. He also explained that the allocation of revenue was based on the Peak & Average ACOS, and that is consistent with the Order issued at Docket No. R-2020-

3018835, and that he agrees on that basis to use the Peak & Average ACOS. However, he did not address that the ALJ preferred the Customer- Demand ACOS but did not use it for reasons previously discussed. Mr. Cline did not attempt to allocate additional revenue requirement to the LDS/LDSS or Flex customers as Mr. Mierzwa did.

Q. WHAT DID OSBA WITNESS MR. KNICHT OBSERVE REGARDING COLUMBIA'S ACOS PROCESS?

A. Similar to Mr. Mierzwa and Mr. Cline, Mr. Knecht explained the process the Company went through, conducting a Customer-Demand ACOS and a Peak & Average ACOS, and an Average ACOS. He stated, "(t)he Company has consistently submitted two alternative ACOS models in its base rate filings stretching back to at least 2008, with a third version that is an average of the two. The models differ only in how mains plan costs are classified and allocated." OSBA Statement No. 1, 13:12-14

He continues, "The Company's "AVE" model is a simple average of these two methods. It should be recognized that the Company's two methods produce enormously divergent results." *Id*. 14:9-10

Q. DOES MR. KNECHT AGREE WITH THE COMMISSON'S FINDINGS AT DOCKET R-2020-3018835 REGARDING MAINS ALLOCATION?

A. No. He states, "While I disagree with the Commission's finding regarding mains cost allocation in the last case, I accept the method employed by the Company in its P&A ACOSS for reasons of Commission precedent." *Id*. 14:2-4. However in this case the facts have changed. There are no errors in the Company's Customer-Demand ACOS, and I presented substantial evidence showing that the Customer-Demand ACOS is the only cost of service methodology based on cost causation. The Commission is not bound by a previous decision made with different facts under different circumstances, and Commission precedence is not a sufficient reason to accept the Peak & Average ACOS.

Q. DID YOU REVIEW THE TESTIMONY OF MR. KNECHT IN THE 2020 COLUMBIA RATE CASE?

A. Yes. Mr. Knecht states his agreement with the concept that mains costs are causally related to the number of customers. He states, "the common sense approach (to which I generally subscribe) is that more footage of mains must be installed to interconnect many small customers than to connect one large customer." Docket R-2020-3018835, OSBA Statement No. 1, 16:5-7. I agree with Mr. Knecht on that point, especially in the rural areas of Columbia's service territory. Regarding the demand component of mains costs, Mr. Knecht argues that "because mains diameters must be sized to meet peak demand, the demand component of mains costs should be allocated only on peak demand." *Id*. 18:20-21. I also agree with Mr. Knecht on that point. On these key points, we are in agreement. Mr. Knecht did not make any statements in this case indicating that it is not appropriate to allocate mains costs based on number of customers and peak design day demand. He acquiesces and accepts Columbia's use of the Peak & Average ACOS in this case for reasons of Commission precedence.

Q. WHAT IS YOUR SUMMARY OF THE POSITIONS OF THE THREE WITNESSES?

A. Mr. Mierzwa, Mr. Cline, and Mr. Knecht all based their agreement with the Company using the Peak & Average ACOS on the Commission Order from the last Columbia rate case, an Order based on an ALJ recommendation to use Peak & Average even though "Customer Demand COSS would be the preferred method." RD at 394.

It is important to establish now that the Customer-Demand ACOS is the method that is based on actual cost causation, and if one ACOS is to be used it should be the Customer-Demand ACOS.

Q. WHY SHOULD MAINS BE ALLOCATED BASED ON THE NUMBER OF CUSTOMERS?

A. Natural gas pipelines are installed to provide service to customers. And unless all the customers are living in one massive apartment building the distribution pipelines need to be extended across a company's distribution service territory. When more customers are added, more pipelines must be extended. It is a clear causal relationship that establishes why the customer component of the Customer-Demand ACOS is necessary. The Columbia System serves the suburbs of Pittsburgh along with numerous rural regions in Pennsylvania. Thus, the density of customers served by Columbia is less dense than if it served the major urban cities in the Commonwealth. This illustrates the reason that allocation of the cost of distribution mains should be done on a customer basis because customers in the less dense areas require more feet of natural gas distribution mains piping to reach them than customers situated in highly dense urban areas. Cost of gas mains are clearly dependent on the number of customers and installing mains to reach those customers. In the case of Columbia, the primary driver of its recent and current rate filings are the increasing capital costs of its distribution system due to extensions to add additional customers or the accelerated pipe replacement program underway to replace older pipe with new plastic gas piping. Both of these functions clearly are customer-driven and that supports allocating a portion of the distribution system costs on a customer basis.

Q. WHY SHOULD MAINS BE ALLOCATED BASED ON PEAK DEMAND AND NOT AVERAGE DEMAND?

A. One of the resources for rate design is the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual (June 1989). The NARUC Manual on pages 23 and 24 states:

> Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

Average demand is based on annual usage and is clearly identified as not appropriate to use as a basis for gas mains allocation. Peak design day demand is the appropriate allocator and the Customer-Demand ACOS is the appropriate study.

Q. WHAT OTHER BASE RATE CASE DECISION APPROVED PEAK DEMAND FOR A GAS COMPANY'S MAINS ALLOCATION DETERMINANT?

A. Recently the Maryland Public Service Commission recognized that distribution mains are demand related and should be allocated to all customers based on each class' contribution to peak demand. On June 13, 2016, the Order was issued in the Baltimore Gas & Electric base rate case No. 9406. The Maryland Public Service Commission approved BGE's ACOS method which bases the allocation on demand, using the non-coincident peak, which is the customer's highest demand during the year. "Distribution mains and associated O&M are classified as demand-related and allocated to all customer classes based on each class' contribution to the winter period total non-coincident peak ("NCP") demand (therms per hour)." Direct Testimony of David E. Greenberg, 31:1-3. This supports my point that in the Customer-Demand ACOS costs should be classified by peak demand, not average demand.

Q. IS THERE VALUE AT EXAMINING COMMISSION RULINGS OUTSIDE OF PENNSYLVANIA?

A. Yes. If we are to look outside of Pennsylvania at other Commission rulings, then examining a more recent New York case would show that in the National Fuel Gas Distribution ("NFGD") system case 16-G-0257, NFGD allocated mains between Customer and Demand using a regression analysis and the zero-intercept radius methodology stating, "The first step in determining the allocation of Distribution Mains (Plant Account 376) is the split between Customer and Demand." Direct Testimony of Cost of Service and Rate Design Panel, 29:9-11. The Company performed a regression analysis, which determined that 58.56% was customer related and 41.44% was demand related. NFGD's customer-demand study was recommended by the Administration Law Judge (RD at 5) and adopted by the New York State Public Service Commission (Order at 88) in 2017.

Q. DO OTHER GAS DISTRIBUTION COMPANIES USE A CUSTOMER-DEMAND COST OF SERVICE MODEL?

A. Yes. In New York, Orange & Rockland ("O&R") produced an Embedded Cost of Service Study for its Gas Department in 2016 for its base rate filing Case 14-G-0494. In that study O&R submitted Exhibit GRP-1, Schedule 1:

> <u>Line 7, Distribution Demand ("Demand Component")</u>
> The Distribution Demand ("Demand Component") consists of the balance of the distribution mains system not allocated to the customer component, and represents fixed costs related primarily to mains. It also includes distribution pressure governors and regulating equipment, used in

> distributing gas from the sellers to the firm classes of services. These costs are allocated to the firm classes in proportion to their maximum one-hour non-coincident use on a zero degree day.
>
> <u>Line 8, Distribution Customer ("Customer Component")</u>
> The Distribution Customer ("Customer Component") consists of the distribution mains system that would be required to connect gas customers with a minimum predominant size pipe, regardless of their demand for gas. It is apportioned to the classes based on the number of services for each class.

Again, the Customer-Demand method is the ACOS that is based on cost causation, and should be accepted as the ACOS in this proceeding.

Q. IS THERE A STATUTE THAT PROHIBITS THE COMMISSION FROM CONSIDERING NEW METHODS DIFFERENT FROM THE PEAK & AVERAGE ACOS?

A. No. The Commission is free to improve on its past decisions based on new information and considerations. That is why I have misgivings about the comments like Mr. Knecht's that precedent dictates the Peak & Average ACOS method

Q. WHAT IS THE SUMMARY OF YOUR TESTIMONY?

A. To ensure that the correct cost allocation of the revenue requirement is based on cost causation, the allocations based on the Customer-Demand ACOS presented by the Company must be used. Mr. Notestone's recommendation of allocating revenue using a study that does not adhere to cost causation principles must be rejected.

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2021-3024296
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

PSU Statement No. 1-SR

SURREBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.

ON BEHALF OF

THE PENNSYLVANIA STATE UNIVERSITY

Dated: July 27, 2021

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. I previously presented direct testimony and rebuttal testimony and now I am presenting surrebuttal testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU" or the "University").

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS SURREBUTTAL TESTIMONY?

A. I will review comments that OCA witness Mr. Mierzwa, I&E witness Mr. Cline, and OSBA witness Mr. Knecht made concerning my allocated cost of service study ("ACOS") recommendations. Their comments reinforce my observations that their views are not based on cost causation. They all base their positions on the Commission ruling in the last Columbia case and ignore the engineering basis that is the causal factor in gas mains design, which is unacceptable.

Q. WHAT REASONS DOES OCA WITNESS MR. MIERZWA STATE TO DISAGREE WITH YOUR RECOMMENDATION TO UTILIZE THE CUSTOMER-DEMAND ACOS?

A. He raises two reasons to oppose my recommendation to utilize the Customer-Demand ACOS. In his rebuttal testimony (OCA Statement 3-R) Mr. Mierzwa's first observes that in the Company's Customer-Demand ACOS, the mains costs are allocated 46 percent based on demand and 54 percent based on the number of customers but in the Company's Peak & Average ACOS, the mains costs are allocated 50 percent based on demand and 50 percent based on annual throughput. He then states, "it is not clear why, if mains are sized based on demands as Mr. Crist claims, the Customer-Demand method should be utilized in this case when it results in less of an allocation of mains costs based on demand than the Peak & Average method." *Id.* 3:24-4:2. Mr. Mierzwa appears to advocate increasing the allocation based on demand from 46% to 50%. The difference in the allocation based on peak demand is minimal but the real difference between the two ACOS lies in the second component which are drastically different.

Q. WHAT IS THE SECOND REASON MR. MIERZWA DISAGREES WITH YOUR RECOMMENDATION TO RELY ON THE CUSTOMER-DEMAND ACOS?

A. Mr. Mierzwa said that the Commission specifically approved the use of the Peak & Average allocation methodology. I understand that was the case, but it was clearly stated in the Final Order that "we are not persuaded to reverse the ALJ's Recommended Decision that adopted the OCA's P&A ACOS and methodology ***in this proceeding***." Final Order at 211 (emphasis added). The wording was clear that the Commission was issuing a ruling that applied to one case and not issuing a policy statement or regulation that must be applied without question in every future case. We are now in a new proceeding with opportunity to consider new evidence such as the facts I presented in my direct testimony demonstrating that only the Customer Demand ACOS is based on cost causation, and the Peak & Average ACOS is not.

Q. DOES MR. MIERZWA BELIEVE THAT THE SECOND COMPONENT OF THE ACOS SHOULD BE BASED ON NUMBER OF CUSTOMERS?

A. No. He does not believe that the second component of the allocation should be based on number of customers. Instead, he believes it should be based on annual throughput.

Q. WHAT IS THE IMPACT OF MR. MIERZWA'S RECOMMENDATION OF THE PEAK & AVERAGE ACOS?

A. Because the results of the two ACOS are significantly different, consideration of the impact on each customer class is important to avoid a skewed impact of a rate increase. Mr. Mierzwa's recommendation would have Small Delivery Service and Large Delivery Service users receive a 36.4% increase, which is neither good for those customers, Pennsylvania jobs, or attracting business to the Commonwealth. In contrast, Mr. Mierzwa recommended only a 16.4% increase for the residential classes. (OCA Statement No. 3, p. 12 Table 3). In previous rate cases Columbia attempted to balance the results of the two ACOS methods by use of the Average ACOS, in order to maintain fairness.

Q. WHAT ARE THE TWO COMPONENTS OF THE CUSTOMER-DEMAND ACOS AND THE PEAK & AVERAGE ACOS?

A. In the Customer-Demand method the allocation is based on peak demand (the first part) and on number of customers (the second part). In the Peak & Average method the allocation is based on peak demand (the first part) and the average throughput (the second part). To make this clear and simple, Mr. Mierzwa and I agree that the significant component of the cost of the distribution system is the cost of gas mains, and we also agree that one of the two components used in the ACOS is the peak demand. We differ in that I have proven that based on cost causation principles, the second component must be the number of customers and not annual throughput. As I explained in my direct testimony, the cost of gas mains depends on the design of the piping. There are two physical measurements that Columbia's engineering department calculates when designing its piping system, the diameter of the pipe and the length of the pipe. I included exhibits with my direct testimony setting forth responses from Columbia regarding how its engineers design pipe and what data they use in that design process. For each pipe, the data used in the design is the expected peak load because that determines the diameter (how "fat" the pipe must be). It must be fat enough to carry enough gas during the coldest days of the winter to satisfy the needs of all of its customers. The other data used are the location of and number of customers because that determines the length of the pipe. It is easy to understand that Columbia has to install enough feet of pipe to connect to all its customers. What is significant when deciding if the ACOS is based on cost causation is that at no time during the engineering design process do the engineers use the annual throughput (also called "average demand" or the "Average" component of the Peak & Average ACOS). The Peak & Average method is not based on cost causation. That is why the Customer-Demand ACOS must be used in this proceeding.

Q. WHY ELSE DOES MR. MIERZWA BELIEVE THE PEAK & AVERAGE STUDY SHOULD BE USED?

A. Mr. Mierzwa stated that in last year's Columbia case the Commission's Order said:

> …we remain of the opinion that although mains serve customers, it is the throughput that determines the mains investment, not the number of customers served. (Order at 217).

OCA Statement 3-R 4:9-12. The Final Order was 275 pages long, plus a table of contents and tables at the end that showed the Commission's allowed revenue increase. In fact, there were 31 pages in the Order that covered the topic of ACOS, and there was significant discussion of the merits of not only the Peak & Average ACOS, but also the Customer-Demand ACOS. It would be misleading to suggest that all those arguments can be summarized in the fragment of one sentence that Mr. Mierzwa included. Because it is the only point he stated, it can easily be picked apart and analyzed piece by piece. First, do mains serve customers? Absolutely, and the Commission does "remain of the opinion" that they do. To suggest that all those miles of pipe are in the ground not to serve customers would be foolish. Next, is it the throughput that ***determines the mains investment***? Absolutely not. It is the peak demand, not the annual throughput, that determines the mains investment. In her recommended decision the ALJ stated that the Customer-Demand ACOS would be the preferred method however due to an "error"[1] she recommended use of the Peak & Average method. The Commission simply approved her recommendation. They ignored that cost of service based on cost causation is the polestar of ratemaking as described in *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth. 2004). All of the data collection from prospective customers used to design the pipeline system focuses on the peak demand, not the annual consumption.

Q. WHAT DID THE BUREAU OF INVESTIGATION AND ENFORCEMENT WITNESS MR. CLINE COMMENT ABOUT THE COMMISSION ORDER IN THE LAST COLUMBIA BASE RATE CASE?

A. Similar to Mr. Mierzwa, in his rebuttal testimony (I&E Statement No. 3-R) Mr. Cline referenced the Final Order in the 2020 Columbia base rate case and he characterized my analysis of the Order "inaccurate and misleading." *Id*. 4:5. However, I note that Mr. Cline did not identify any statement of mine that he believed was inaccurate, and did not identify any of the direct quotations from the Order as inaccurate. Although he may not agree with my logical presentation, his disagreement does not make my testimony "misleading". It simply means that he either does not understand the issue or is not able to refute it.

[1] The "error" was Mr. Mierzwa's characterization of the Company's categorization of distribution system piping by pressure, which Mr. Notestone did not do in the ACOS calculations in this case.

Q. HOW DO YOU ADDRESS THE FIRST CITATION FROM THE 2020 ORDER THAT MR. CLINE PRESENTED?

A. He first presented the following quote:

> Based on our review of the record, and as noted by the ALJ, we have consistently used the Peak & Average methodology for the allocation costs for NGDCs. In this regard, we find that the Customer-Demand method and the Average ACCOSS, which depends on the Customer-Demand methodology, would be inconsistent with Commission precedent and generally accepted principles for NGDCs because they both contain customer cost components.

Id. 4:10-17 (quoting 2020 Order at 215).

As I explained in my Rebuttal testimony, the only reason Mr. Cline stated for supporting the use of the Peak & Average ACOS in this case was alleged Commission precedence. When discussing the Peak & Average ACOS in his direct testimony he states:

> "This methodology was accepted by the Commission in the Company's last base rate case"

(*id.* 13:3-4) and

> "Consistent with the Commission's Order from the last base rate case, discussed above, the Company utilized the second ACOS study sponsored by Mr. Notestone, which is the peak and average study, presented on Columbia Exhibit No. 111, Schedule No. 2 to allocate the proposed revenue increases."

Id. 13:10-13. Mr. Cline conducted no independent analysis of any ACOS and did not even validate the ACOS he supports. He simply cited that the Commission approved the Peak & Average ACOS in the last case and that was the only reason he cited for supporting it.

Q. HOW DO YOU ADDRESS THE SECOND CITATION FROM THE 2020 ORDER THAT MR. CLINE PRESENTED?

A. He then presented the following quote in his rebuttal testimony:

> "we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment."

Cline Rebuttal, I&E Statement 3-R, 4:20-22 (quoting 2020 Order at 218).

I will address two points in this excerpt from the Final Order. First is the wording "in this proceeding", which means exactly that. The Commission was not ordering that all future natural gas utility filings use the Peak & Average ACOS. It made a ruling that applied in one proceeding to the specific facts and studies presented in that proceeding, and made that ruling in large part due to the recommendation of the ALJ who stated concern with the so called "errors" in the Company's Customer-Demand ACOS. I explained in my direct testimony in this case that the "errors" were not mathematical mistakes but instead a characterization that was used by the OCA witness who was advocating a different ACOS methodology. The ALJ actually stated that the preferred method was the Customer-Demand ACOS. In stating that, the ALJ showed that she was not limited by previous Commission decisions and that cases should be decided based on the facts presented in that case. The second point to address is the "premise of load-based investment." I have soundly addressed in this and my prior testimony the misunderstanding that the investment in gas mains of a distribution system is based on annual load. It is not. There is nothing in the engineering, design, or construction of gas mains that is based on annual loads. Gas mains are engineered to satisfy two requirements -- that they are sized large enough to meet peak demand and that they are constructed long enough to connect to customers. Mr. Cline continues to rely solely on the 2020 Commission Order in every statement he makes disagreeing with the concept that the Customer-Demand ACOS is the appropriate method to use in this proceeding. He said:

> "Mr. Crist's insistence that costs should be allocated based on the customer-demand methodology because of how the Company stated the system is designed is not consistent with the Commission's historic determination of cost causality." Cline Rebuttal, I&E Statement 3-R, 5:8-11

> "The Commission stated on page 217 of the 2020 Columbia Order that 'we remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment, not the number of customers served.'" *Id.* 5:14-16

> "The Commission should not reverse itself and has previously reflected the proper recognition that distribution mains are built on the basis of year-round demands as well as peak demands. Mr. Crist did not provide any reasonable rationale to accept a methodology that the Commission rejected less than six months ago." *Id.* 6:11-15

Mr. Cline, who is not a professional engineer, conducted no engineering analysis of how a gas distribution system is planned, designed, and built, and in his third quotation above refuses to find rationales that are based on hard engineering and science to be "reasonable". Apparently, Mr. Cline is content to repeat history even when presented with new engineering facts. His objections to the use of the Customer-Demand ACOS must be rejected.

Q. WHAT DID OSBA WITNESS MR. KNECHT OBSERVE REGARDING YOUR DIRECT TESTIMONY RECOMMENDING THE CUSTOMER-DEMAND ACOS?

A. Mr. Knecht again explained the process the Company went through, conducting a Customer-Demand ACOS and a Peak & Average ACOS, and an Average ACOS and that the Company relied on recent Commission precedent when using the Peak & Average ACOS to develop its revenue proposal. He states, "I agree with Mr. Crist that there are economies of scale for serving large customers, and that these economies can be recognized in a CD ACOS. As a practical matter, however, the Commission does not." OSBA Statement No. 1-R 2:28-3:2 Mr. Knecht's observation is accurate except that just because the Commission did not choose the Customer-Demand ACOS in the 2020 Columbia Order, does not mean as a general principle the Commission will not recognize the value and accuracy of the Customer-Demand ACOS. He further states that "(f)or decades, the Commission has consistently declined to approve the inclusion of a customer component to gas mains costs, such as that used in Columbia's CD method. Moreover, in its decision in Docket R-2020-3018835, the Commission explicitly reiterated its support for earlier decisions which supported the idea that there is no customer component of mains costs, and that mains costs are (somehow) causally related to both peak demand and annual throughput." I interpret his statement as supportive of my position that there is no causal relationship between mains cost and annual throughput. It appears that Mr. Knecht did not wish to advance a position different from a recent Commission decision and therefore he produced a revenue allocation based on the Peak & Average method.

Q. ALL THREE WITNESSES THAT DISCUSSED THE ACOS DID NOT CHALLENGE THE METHOD THE COMMISSION SELECTED IN THE LAST CASE. ARE YOU IGNORING THE COMMISSION'S DECISION?

A. No, I am not ignoring the words of the Commission in its Order in the 2020 case. I have read and reread the order and identified the rationale cited by the Commission in reaching its decision. The Commission stated: "the Peak & Average allocation methodology is the most appropriate allocation methodology to use in ***this*** proceeding because it is based on the premise of load-based investment." (Final Order at 218; emphasis added) Focusing on the words "use in this proceeding" tells me that the Commission was open to, and will consider any new facts or evidence to be presented in the future, and that one ruling made in 2020 was not intended to shut the door on presenting new evidence and arguments in the future. When the Commission stated, "based on the premise of load-based investment" it directed me to examine the actual causal factors of gas mains investment, and I did that examination not based on whims, or class preferences, or non-scientific means but instead I dug into the engineering principles that gas distributions systems are based on, and more specifically on which Columbia Gas' distribution system are based. I note that of the other witnesses that discussed the ACOS, Mr. Mierzwa and Mr. Knecht are not engineers, and that while Mr. Cline has a degree in Civil Engineering, he has not performed any natural gas pipeline engineering design work during his career. Because I am a Registered Professional Engineer in the Commonwealth (license number PE029041E) and because in my decades of employment with several major natural gas utilities I have reviewed dozens of natural gas main line extension engineering studies, I know the methods that are used to design piping systems. The Commission was seeking a reason to consider an ACOS method that is based in cost causation to comply with the polestar of ratemaking and I have provided such evidence. None of the other witnesses I have discussed have produced any evidence that the Peak & Average method is based on cost causation.

Q. MR. KNECHT OBSERVES YOU DID NOT SUBMIT A REVENUE ALLOCATION OR RATE DESIGN BASED ON THE CUSTOMER-DEMAND ACOS. WHAT DO YOU RECOMMEND?

A. I recommend that the Company's Customer-Demand ACOS be used as the primary basis to determine the revenue allocation. I have used the Company's Customer-Demand ACOS and prepared a revenue allocation based on the results which I am including as Exhibit PSU-SR-1. This exhibit contains three scenarios that I discuss below. I recommend adoption of the third scenario as the most just, reasonable, and non-discriminatory rate design based on cost causation principles. In that exhibit I have determined revenue allocation under several scenarios.

Q. HOW DID YOU TREAT MLDS AND FLEX CLASSES?

A. In all my scenarios, I did not alter the Company's recommendation for revenue allocation to the MLDS and Flex classes. I accept and agree with the Company's rationale that the MLDS class customers that are generally proximate to a transmission pipeline are overpaying based on the amount of rate base allocated to the class, therefore the Company allocated no revenue increase to them. I also agree with the Company's treatment of the Flex class customers, only increasing the revenue allocation by the amount of service charge increases in this case. The Company provided convincing evidence that it thoroughly analyzes competitively situated customers and negotiates amounts necessary to retain their patronage and such agreements do not allow for increases.

Q. WHAT DOES THE TERM UNITIZED RETURN MEAN AS USED IN EXHIBIT PSU-SR-1?

A. The unitized return is the ratio of the class rate of return on rate base to the Company's overall rate of return on rate base. A unitized return greater than 1.0 indicates a class is overpaying, while a unitized return less than 1.0 indicates a class is underpaying. In my first example there is no class cross-subsidization and the class unitized returns are all similar at 1.02.

Q. WHAT IS THE FIRST SCENARIO?

A. Using the Customer-Demand ACOS and bringing each of the customer groups to similar class rates of return results in the SGS/DS-2, SDS/LGSS, and LDS/LGSS classes receiving a decrease. I do not believe it is practical or realistic to adjust class revenues to provide decreases and I am not recommending that, but have included it to illustrate the dramatic differences in results that depend on the selection of an ACOS.

Q. WHAT IS THE SECOND SCENARIO?

A. In my next scenario I did not allow any decrease in revenue collection from the SGS/DS-2, SDS/LGSS, and LDS/LGSS classes, however this resulted in the RSS/RDS class bearing most of the increased revenue requirement, and I did not find that acceptable.

Q. WHAT IS THE RECOMMENDED SCENARIO?

A. In my third scenario I balanced the increases by accepting the Company's and OSBA's recommendation for the SGS/DS-1 and SGS/DS-2 classes. I then increased the LDS/LGSS class by 11.14%, which is 3/4 of the percentage of the overall Company request. I then assigned revenue to the SDS/LGSS class to achieve a similar unitized return as the LDS/LGSS class, which is still high at 2.74. While in theory, all classes should have the same unitized return of 1.0, in practice that is impossible to achieve due to the reason mentioned previously of not allowing any class revenue decreases. The unitized return of SDS/LGSS and LDS/LGSS classes is high at 2.74. The remainder of the revenue increase was assigned to RSS/RDS. That class only has a unitized return of 0.81 and the percentage increase assigned is only 1.11% higher than the overall Company request, so will not impose an undue hardship. Using the Customer-Demand ACOS, and making the appropriate adjustments in my recommended scenario as described provides a fair, just and reasonable revenue allocation based on cost causation.

Q. WHAT COMMENT DID COMPANY WITNESS MS. BELL MAKE ABOUT YOUR RECOMMENDATION?

A. She stated, "the Company does not believe that basing the revenue allocation in this case entirely on the Peak & Average Study would produce a reasonable result, particularly with respect to allocation of mains cost to the LDS/LGSS class. The Company also cannot agree with Mr. Crist that the Customer/Demand study should be the sole basis of allocating revenue requirement among the rate classes." (Columbia Gas Statement 3-R, 8:3-8) I am in agreement with Ms. Bell on that point as I explained earlier because that would result in revenue decreases to several customer groups. I have presented a balanced recommendation that assigns revenue increases to every customer group (except MLDS).

Q. HOW DID MS. BELL CHARACTERIZE YOUR PREFERENCE OF THE CUSTOMER-DEMAND ACOS?

A. Ms. Bell referenced the Company's data request responses that I included in my direct testimony that describe how the Company actually engineers and designs its distribution piping system. She states, "Mr. Crist supports his preference based on what he has identified as facts and engineering." *Id.* 4:20-21. I also add that in addition to facts and engineering my recommendation for the Customer-Demand ACOS is based on cost causation, as it is the only ACOS under consideration in this proceeding that is based on how the Company designs and constructs its system. The Peak & Average ACOS is not based on cost causation, and therefore should be rejected as the basis for cost allocations.

Q. WHAT IS YOUR RECOMMENDATION REGARDING RATE DESIGN?

A. I accept the Company's rate design for the SDS/LGSS and LDS/LGSS classes. I offer no opinion on the rate design for the other customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING SCALE BACK?

A. If the Company's requested revenue increase is not awarded but a lesser amount is determined to be appropriate then the allocation of that scaled back amount should be in similar proportion as the allocations in my recommended scenario. I oppose the scale back proposed by Mr. Cline that disproportionately adjusts the revenue allocation, and further increases class cross-subsidization. Such an allocation is not just and reasonable.

Q. WHAT IS THE SUMMARY OF YOUR TESTIMONY?

A. To ensure that the correct cost allocation of the revenue requirement is based on cost causation, the revenue allocations must be based on the Customer-Demand ACOS presented by the Company. Mr. Notestone's recommendation of allocating revenue using the Peak & Average study that does not adhere to cost causation principles must be rejected. The revenue allocation I present in this testimony that is based on the Customer-Demand ACOS is recommended.

Q: DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

Exhibit PSU-SR-1: Recommended Revenue Allocation

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

LINE NO.	ACCOUNT TITLE (A)	TOTAL COMPANY (C)	RSS/RDS (D)	SGS/DS-1 (E)	SGS/DS-2 (F)	SDS/LGSS (G)	LDS/LGSS (H)	MLDS (I)	FLEX (J)
	I: REVENUE ALLOCATION BASED ON C-D ACOS	$	$	$	$	$	$	$	$
1	PROPOSED REVENUE – CUSTOMER/DEMAND ALLOCATION	759,484,841	608,988,083	64,800,000	50,500,000	18,550,000	11,900,000	1,332,216	3,414,542
2	TOTAL REVENUE - CURRENT	661,206,723	483,512,517	58,419,182	64,290,143	30,342,909	19,911,382	1,331,837	3,398,752
3	REVENUE INCREASE	98,278,118	125,475,566	6,380,818	(13,790,143)	(11,792,909)	(8,011,382)	379	15,790
4	RATE OF RETURN EARNED ON RATE BASE	7.880%	8.052%	8.033%	8.041%	8.024%	8.036%	157.627%	-1.562%
5	UNITIZED RETURN	1.00	1.02	1.02	1.02	1.02	1.02	20.00	(0.20)
6	INCREASE PERCENTAGE	14.86%	25.95%	10.92%	-21.45%	-38.87%	-40.24%	0.03%	0.46%
	II: REVENUE ALLOCATION WITH NO DECREASES								
7	PROPOSED REVENUE – C/D BUT NO DECREASES	759,484,841	578,493,648	61,700,000	64,290,143	30,342,909	19,911,382	1,332,216	3,414,542
8	TOTAL REVENUE - CURRENT	661,206,723	483,512,517	58,419,182	64,290,143	30,342,909	19,911,382	1,331,837	3,398,752
9	REVENUE INCREASE	98,278,118	94,981,131	3,280,818	0	0	0	379	15,790
10	RATE OF RETURN EARNED ON RATE BASE	7.880%	6.998%	6.992%	14.860%	20.299%	18.642%	157.627%	-1.562%
11	UNITIZED RETURN	1.00	0.89	0.89	1.89	2.58	2.37	20.00	(0.20)
12	INCREASE PERCENTAGE	14.86%	19.64%	5.62%	0.00%	0.00%	0.00%	0.03%	0.46%
	III: REVENUE ALLOCATION BALANCED (RECOMMENDED)								
13	TOTAL REVENUE - BALANCED	759,484,841	560,737,940	66,867,000	73,403,143	31,600,000	22,130,000	1,332,216	3,414,542
14	TOTAL REVENUE - CURRENT	661,206,723	483,512,517	58,419,182	64,290,143	30,342,909	19,911,382	1,331,837	3,398,752
15	TOTAL REVENUE INCREASE	98,278,118	77,225,423	8,447,818	9,113,000	1,257,091	2,218,618	379	15,790
16	RATE OF RETURN EARNED ON RATE BASE	7.880%	6.327%	8.727%	19.367%	22.579%	22.559%	157.627%	-1.562%
17	UNITIZED RETURN	1.00	0.81	1.11	2.46	2.74	2.74	20.00	(0.20)
18	INCREASE PERCENTAGE	14.86%	15.97%	14.46%	14.17%	4.14%	11.14%	0.03%	0.46%

PENNSYLVANIA WEATHERIZATION PROVIDERS TASK FORCE

PWPTF Statement No. 1

Direct Testimony of Eugene M. Brady

In Re: Columbia Gas of Pennsylvania, Inc.
Request for a Rate Increase

Docket Number: R-2021-3024296

Q. Please state your full name and business address.

A. Eugene M. Brady, 165 Amber Lane, PO Box 1127, Wilkes-Barre, Pennsylvania 18703-1127.

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

A. I am employed by the Commission on Economic Opportunity (CEO) as Executive Director. I am submitting this testimony on behalf of the Pennsylvania Weatherization Providers Task Force as Chair of the Task Force.

Q. What are the interests of the Task Force in this rate case?

A. The Pennsylvania Weatherization Providers Task Force, Inc., is a Pennsylvania non-profit corporation and a statewide association of thirty-seven (37) organizations providing utility assistance and energy conservation services in each of the Commonwealth's sixty-seven counties. The Task Force, through its member agencies, a number of which are Pennsylvania community-based organizations, administers universal service programs for a number of utility companies, including Columbia Gas. The Task Force members serve low-income ratepayers and it is part of our responsibility to our constituency to advocate for their interests in regulatory proceedings and this proposed request will certainly have an impact upon those low-income ratepayers. In addition to the affordability of transmission and distribution rates, the Task Force is particularly interested in the adequacy and operation of a company's universal service program.

Q. What background and experience in energy issues qualify you to submit testimony in this case?

A. I have served as the Executive Director of the Commission on Economic Opportunity since 1978. During my tenure, CEO's experience and the expertise of its staff in energy programs has been recognized on state and national levels. CEO's energy related programs have been acknowledged by receipt of a Superior Achievement Award from the United States Department of Energy. CEO has weatherized more than 25,000 homes under the U.S. Department of Energy Weatherization Assistance Program. CEO, like a number of Task Force members, also serves as a subcontractor for universal programs operated by a number of Pennsylvania gas and electric utility companies.

CEO is also the PA Department of Public Welfare's contracted operator of the crisis component of the Low Income Home Energy Assistance Program (LIHEAP) in Luzerne and Wyoming Counties. CEO was also a major contractor for PPL in the Low Income Renewable Energy Pilot, and secured funding and installed several solar thermal water heating systems for the former PG Energy and UGI Gas Division.

Throughout my career I have served on numerous Boards, Committees and Task Forces in the energy field under the auspices of the US Department of Energy, The PA Department of Community & Economic Development and the PA Public Utility Commission. Presently, I serve on the Board of Directors of the National Center for Appropriate Technology; I am on the Board of the National Community Action Foundation, Chair of the Department of Community & Economic Development Weatherization Policy Advisory Council and, as indicated above, I am the Chair of the Pennsylvania Weatherization Providers Task Force.

Q. Before addressing the specifics of your testimony, does the Task Force take a position on whether the Company's rate increase should be granted?

A. Our main focus is on the funding and availability of universal service programs and opposing rate designs that discourage conservation. In this case, we do not necessarily oppose a rate increase, but we do oppose the rate increase requested and would oppose <u>any</u> rate increase unless it is accompanied by measures that would provide additional relief to the Company's customers, particularly low-income customers, from the effects of a rate increase, especially in light of the fact that we are still dealing with the economic difficulties caused by the COVID-19 crisis.

Q. If a rate increase is granted in this case, what type of measures would you like to see accompany that rate increase?

A. Measures similar to those adopted by UGI Gas when its rate increase was recently granted. In that case, filed to R-2019-3015162, UGI Gas proposed, and the parties and PUC approved, an Emergency Relief Program (ERP) that provided among other things, arrearage forgiveness, extended payment arrangements, expanded hardship funding and additional LIURP funding.

Should a rate increase be granted in this case I would like to see commensurate relief provided to this Company's most vulnerable customers through measures similar to those that were part of the ERP approved in the recent UGI Gas case.

Q. Please describe the other areas of your testimony.

A. My testimony will address the Company's proposal to increase the fixed monthly charge for residential customers as well as proposals to help low-income customers deal with any resulting rate increase.

In its request for a rate increase the Company does not propose any additional increase in funding or measures that would help low-income customers deal with the proposed rate increase. Further, an increase in the fixed monthly charge, as requested by the Company, would negatively impact a customer's motive and ability to conserve energy. The company's proposal if granted would increase rates, discourage conservation and leave a customer with less ability to conserve energy and less ability to reduce their bills. Despite the impact of its proposal on residential customers, and in particular low-income customers, the Company's proposal offers nothing in the way of changes or increases in funding to its low-income programs, programs that would help mitigate the negative impact of the Company's proposals especially in light of these difficult economic times.

Despite these difficult financial times for all, including ratepayers, the Company is requesting an increase in annual distribution revenues of $98.3 million. A residential customer using an average 70 therms per month would see an increase from $100.77 to $115.37 per month, or 14.49 percent. Further, this Company was granted a rate increase in 2020 without any increase in funding that would help ratepayers deal with that rate increase (R-2020-3018835); here, the Company requests another rate increase and again offer nothing additional to help low-income customers

Q. What rate design issue would you like to address?

A. In this case the Company is proposing to increase its fixed monthly charge, from $16.75 to $19.33, an increase of over 15%. I am concerned about this proposal and the Task Force opposes any increase to the fixed monthly customer charge.

Part of the proposed increase to residential customer's rates will be due to this increase in the fixed monthly customer charge. This increase in the monthly fixed charge concerns me, as it has the Commission in recent, because it discourages conservation and impacts a customer's ability to save money through conservation; as the Company moves towards charging customers based upon the Company's fixed costs and away from a customer's consumption there is less incentive, and ability, to conserve. One of the only defenses a family, particularly a poor family, has against the sharp increases in energy costs is to conserve – lower the thermostat, seal air leaks, change filters regularly, add more insulation, get a more efficient heating unit, etc. The Company's proposal to increase the fixed costs greatly impacts a customer's motive to conserve and the ability to lessen the impact of any rate increase. The combined effect of an increase in rates and an increase in fixed monthly charges, without any changes to universal service funding or other measures to help low-income customers, not only results in higher rates but also lessens the ability of customers to deal with those increases. In particular, the negative impact would be particularly harsh on the Company's low-income customers and the Company's proposed request ignores the interests of its low-income customers.

In prior cases, PUC Commissioner Cawley has expressed concerns about proposals to increase the fixed portion of a customer's bill or any proposal that would impact a customer's motive and ability to conserve. In a National Fuel Gas case (No. R-00061493) Commissioner Cawley issued a statement while the case was pending concerning NFG's proposal to increase its fixed monthly customer charge. That statement read in relevant part:

"This proposed change raises important policy issues that affect this Commission's goals of promotion and encouragement of conservation of natural resources, including natural gas. Given the extremely volatile and currently high natural gas prices facing this nation, a policy that does not optimally reward consumers for conservation efforts, but instead charges fixed fees regardless of usage, should, I feel, be addressed by the parties to this case.**"**

We share Commissioner Cawley's concerns and believe that fixed monthly charges should be held in check.

Q. How does the effect of the Company's requests impact upon your testimony in this case?

A. I believe that should a rate increase be granted there should be relief offered in the form of increases to universal funding programs and other relief that would help low-income customers deal with any increase granted. For a typical residential customer, a 14.49% increase is substantial, but for a low-income customer, the effects can be dramatic, especially in this economic climate. High utility costs are not the only challenge for a poor person. Our agencies have been helping low-income people for years and know firsthand that they face financial challenges on many fronts -- housing, energy costs, food and health care -- and a dramatic increase in any of those areas can have a devastating impact. The increase in the number of unemployed Pennsylvanians during the COVID-19 crisis is beyond dispute and most believe the economic downtown will last beyond the ending of the COVID-19 emergency.

It is for these reasons that if an increase is granted it should be conditioned upon an increase in funding and relief to the Company's low-income customers.

Q. Should a request for a rate increase be granted what type of measures would you suggest be implemented for low-income customers?

A. As I indicate above, I believe that the measures similar to those adopted by UGI Gas should be part of any rate increase granted in this case. I believe that LIURP and Hardship funding should be increased.

In discovery responses in this case the Company indicated as of April 2021 it had 69,554 confirmed low-income customers with 96,648 estimated low-income customers as of March 2021, nearly 25% of its residential customers. As a result of this proceeding rates are likely to increase, a customer's ability to conserve will decrease (if the fixed monthly charge is increased) yet no additional relief is being provided to customers that would allow them to increase their conservation of energy and decrease their monthly bills.

Q. Turning now to universal service programs what issues would you like to address?

A. I want to address the Company's low-income usage reduction program (LIURP), WarmWise. Annual funding for WarmWise for the years 2020 through 2023 is set at

$4,875,000.

We are proposing increased funding for LIURP because there is an unmet need for LIURP services. In its most recent need assessment, the Company estimated that there were 18,647 households eligible for LIURP services. With annual funding at $4,875,000 the Company anticipates providing LIURP services to 499 homes per year. Accordingly, the Company estimates that it would take 37 years to weatherize 100% of the homes that could receive weatherization services.

This combination of over 18,000 customers eligible for LIURP and what may be a significant rate increase, requires an increase in LIURP funding. Further, the current level of LIURP funding did not account for this anticipated rate increase.

Q: Do you have any recommendations regarding the funding level for LIURP?

A: Yes. With over 18,000 customers in need of LIURP services it is clear that there is a great need for those services. I am recommending that should a rate increase be granted then the number of customers served annually be increased by 75. That would begin to meet the unmet need for LIURP services. With an average LIURP cost of approximately $7,200, I am recommending additional annual LIURP funding of $540,000 beginning in the 2022 program year.

Q: Do you have any other recommendations regarding the LIURP program?

A: Yes. The increased funding for LIURP and the increased number of households targeted represents a need to ‘ramp up’ the LIURP program. Additionally, the number of homes weatherized in 2020 was reduced due to COVID restrictions which represents an additional need to ramp up services.

The Task Force believes that there will be a need for more partnerships with agencies experienced in the providing of services to poor people, including weatherization services. Our member agencies have the expertise in developing and operating programs that benefit people and communities. These organizations serve thousands of low income and disadvantaged members of the community; they have direct knowledge of the barriers and impediments to self-sufficiency, and continually innovate and evolve the service delivery system to better meet the needs of the population they serve. Community based organizations are governed by volunteer Boards of Directors; accountable to the communities they serve, and are not conflicted by a duty to shareholders and investors. The focus and active experience of community-based organizations make them singularly suited to speak for the needs of the community. As such, the development and evolution of these programs should occur on a community level, by organizations that are experienced in these programs not on a utility staff level. These are "people" programs and community based organizations are best qualified to implement them. I am recommending that the Company partner with our member agencies in the administration and implementation of its LIURP program. Our member agencies are located throughout the Company's service territory, have experience in the administration and implementation of LIURP programs and are needed because of the expansion of the Company's LIURP funding.

Q. Are there any other universal service topics that you want to address?

A. Yes. The Task Force recommends that the Company's contribution to its hardship fund be increased commensurate with the percentage increase in rates to the residential class that results from this proceeding. Although modest in comparison to other universal service funding, the proposal will help customers deal with a rate increase in these difficult economic times.

I also recommend that hardship funding be distributed in accordance with the percentage of low-income customers in the counties served by the Company.

Q. Can you please summarize your recommendations?

A. Yes. The Task Force is recommending the following:

1. That the Company's request to increase its fixed residential monthly customer charge be denied;

3. That annual funding for LIURP be increased beginning in program year 2022 to $5,415,000 annually and that any unused funds be carried over and added to the following year's funding;

4. That the Company partner with member agencies of the Task Force in the development, implementation and administration of its LIURP program;

5. That the Company's contribution to its Hardship fund be increased commensurate with the percentage increase in residential rates that result from this proceeding;

6. That Hardship funds be distributed in accordance with the percentage of low-income customers in the counties served by the Company.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024296
	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

The undersigned certified that he served a copy of the foregoing Pennsylvania Weatherization Providers Task Force Statement No. 1 – Direct Testimony of Eugene M. Brady upon the following participants this 16th day of June, 2021, via electronic mail:

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