COLUMBIA STATEMENT NO. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	

SURREBUTTAL TESTIMONY OF
ANDREW S. TUBBS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

September 16, 2020

Q. Please state your name and business address.

A. My name is Andrew S. Tubbs and my business address is 800 North 3rd Street, Suite 204, Harrisburg, PA 17102.

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 Vice President, External and Customer Affairs.

Q. Have you previously filed testimony in this matter?

A. Yes. I have adopted Columbia Statement No. 1, the Direct Testimony of Michael Huwar, as he is no longer with the Company. I have also provided Rebuttal Testimony.

Q. What is the purpose of your Surrebuttal testimony?

A. I will respond to the rebuttal testimony of OSBA witness Knecht, wherein he suggests that a 2018 incident in the Company's Massachusetts affiliate supports denial of Columbia's requested management adder, and, in his view, may have negatively impacted the Company's cost of debt capital. Specifically, Mr. Knecht references an incident that occurred on the Columbia Gas of Massachusetts ("CMA") system in 2018, and seeks to impugn the management effectiveness of the Company for an event on the system of that affiliate. Mr. Knecht's assertions are without merit.

Q. Please explain.

A. First, as discussed by Company Witness Moul in Columbia Statement No. 8-SR, the inference that the cost of capital was impacted by the 2018 event in Massachusetts is simply not true. Second, while CMA is an affiliate of the Company, it is a stand-alone company with its own management. While Mr. Knecht correctly notes that Columbia provided assistance to CMA, providing mutual assistance to an affiliate does not demonstrate poor management performance by Columbia Gas of Pennsylvania. Indeed, Columbia and its employees are proud of the work performed to assist those impacted by the 2018 incident. The cost of this work, which was completed consistent with a Commission-approved Affiliate Interest Agreement (Docket No. G-2018-3004657) was reimbursed by CMA. While it did impact the Company's work efforts in 2019, as addressed by Columbia witness Kitchell, in Columbia Statement No. 14, the Company has completed replacement work that had been originally projected for 2018 in addition to completing its planned 2019 infrastructure replacement program. So, in addition to assisting its affiliate in Massachusetts, Columbia Gas of Pennsylvania has been able to fulfill its pipeline replacement commitments at home. These are laudable achievements.

Q. Does this complete your Prepared Surrebuttal Testimony?

A. Yes, it does.

Redacted

COLUMBIA STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
ANDREW S. TUBBS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew S. Tubbs and my business address is 800 North 3rd Street,Suite 204, Harrisburg, PA 17102.

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 Vice President, External and Customer Affairs.

Q. What is your educational and professional background?

A. I received a Bachelor's of Arts Degree in Political Science from the University of Pittsburgh and a Juris Doctor from Widener University School of Law in Harrisburg, Pennsylvania. In 1990, I began my professional career with Allegheny Electric Cooperative, Inc., and the Pennsylvania Rural Electric Association as a Research Analyst and Right-of-way Coordinator, where I provided support for both the in-house and member cooperative counsels, and managed right-of-way procurement for transmission line projects, including easement negotiations, permit acquisition, title searches and eminent domain proceedings. In 1997, I was promoted to Staff Attorney, where I undertook legal research and writing relative to utility law, employment law, environmental compliance, and property law, and provided legal representation relative to regulatory and legal matters. Beginning in 1998, I was employed by the Pennsylvania Public Utility Commission. My first position was as an Assistant Counsel, where I provided counsel to the Commission in all areas of utility law before state and federal appellate courts, researching and evaluating legal positions, preparing briefs and making oral arguments. In 2001, I accepted the position of Counsel for Pennsylvania Commissioner Kim Pizzingrilli, where I provided counsel on all state and federal regulatory and legislative matters relative to the gas and electric industries. From 2006 to 2014, I was an associate in a private law firm, where I represented gas, electric and water clients before the Pennsylvania Public Utility Commission and the Federal Energy Regulatory Commission. I joined NiSource Corporate Services Company ("NCSC") in 2014, where I served as legal counsel to Columbia and Columbia Gas of Maryland, Inc. in regulatory proceedings before the Commission and the Maryland Public Service Commission. In March 2018, I was promoted to my current position as Vice President, External and Customer Affairs.

Q. Have you previously filed testimony in this matter?

A. No. However, in addition to my rebuttal testimony, I will assume responsibility for the Direct Testimony of Michael Huwar, who is no longer with the Company. In addition, I will assume responsibility for all the discovery responses, and corresponding attachments offered by Mr. Huwar prior to his departure.

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 Niambele, Office of the Consumer Advocate

("OCA") witnesses Rubin and Colton, Office of the Small Business Advocate ("OSBA") witness Knecht, Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") witness Miller, and Pennsylvania State University ("PSU") witness Crist.

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

A. I will be address the following issues raised by multiple parties in this proceeding:

- Columbia's response to the impacts of COVID-19 on its customers;
- Status of Columbia's infrastructure replacement program;
- Recovery of Universal Service costs from Commercial and Industrial customers;
- Columbia's proposed management adder;
- PSU service issues; and
- Flex rates

II. COVID 19

Q. Would you like to address testimony regarding the impacts of COVID-19 on Columbia's customers?

A. Yes, I would. A number of witnesses advocate that Columbia's requested rate increase be denied due to the economic impact of COVID-19 on the Company's customers. While I appreciate and empathize with the concerns raised by these parties, as the pandemic presents a difficult challenge for all, a flat denial of the proposed increase in rates, as explained by Columbia witness Cawley (Columbia Statement No. 16-R), is both unlawful and unconstitutional. As Mr. Cawley further explains, comparing Columbia, a regulated utility with an obligation to provide safe, adequate and reasonably continuous service, to situations facing various unregulated businesses, is fundamentally improper. Further, as explained by Columbia witness Bishop (Columbia Statement No. 17-R), proposals to deny the rate increase in its entirety fail to recognize the benefits that Columbia's ongoing capital investment program has on jobs and the general economic health of Columbia's service territory. Additionally, Columbia has been proactive in reaching out and assisting our customers during the pandemic.

Q. Please explain how the Company has supported customers in response to the COVID 19 Pandemic?

A. The Company has adapted its policies and procedures, as well as implemented additional initiatives, in an attempt 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.

A. . <u>Customer Education and Outreach:</u>

Q. Please provide descriptions and/or examples of Columbia's outreach and education to its customers about their rights and responsibilities,

available assistance programs, and energy efficiency and conservation opportunities during the COVID-19 pandemic.

A. Columbia is using 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.

Please see Exhibit AST 1-R for samples of these materials.

Q. Please provide an additional example of Columbia's proactive outreach measures.

A. In response to decreased call volumes in our Customer Care Center in Smithfield, Pennsylvania, the Company decided to reverse the calls. That is, our customer service representatives began to make outbound calls to customers who previously were eligible for LIHEAP assistance, but who, according to Columbia's records, did not appear to have sought LIHEAP assistance currently. The purpose of the calls was to obtain permission to apply to the LIHEAP program on their behalf. In addition, Columbia continues to send out applications to customers upon request.

Q. Has Columbia's outreach to these customers been successful?

A. Yes. To date, the Company has assisted 1,376 customers in receiving $405,142 in LIHEAP Recovery CRISIS assistance, primarily as a result of outreach efforts made by company representatives to customers. To determine customer eligibility for assistance, the Company's Universal Services team manually reviewed 7,048 accounts that initially met eligibility criteria. As a result of this review, the Company attempted to contact the 4,544 customers identified as eligible, based on prior grant amounts and arrears. Of the 1,376 customers that received assistance, Columbia processed applications on behalf of 947 customers, at the customer's request.

B. <u>Termination/Billing/ Flexible Payment Plans:</u>

Q. Is the Company currently terminating service to its customers?

A. No. Columbia ceased performing customer shut-offs for all customers on March 13, 2020, and consistent with the Pennsylvania Public Utility Commission's

("Commission") Order at Docket M-2020-3019244, Columbia continues to suspend customer shut-offs.

Q. What are the Company's plans regarding service terminations once the Commission decides to lift the moratorium on utility shut-offs?

A. The Company has voluntarily developed a two-phased plan for collection activity that complies with the customer protection regulation in the Pennsylvania Public Utility Code. First, prior to restarting shut-offs, Columbia will send reminder letters to customers advising them that they are in arrears, and informing them of their current account balances. The letter will also inform the customers that the Company is offering flexible payment arrangements, and will refer customers to energy assistance programs. During the second phase, which will not commence until after the Commission lifts the moratorium, the Company will resume termination notices with the intent to shut off for nonpayment starting with a new 10 day termination notice. As part of this phase, the Company will prioritize collections for those customers with high balances.

Q. What types of payment arrangements is Columbia offering?

A. For residential customers, the Company is offering two options. In addition to Columbia's normal budget plus payment plan offered to its customers based on financial information and household size, Columbia is providing customers the option of a six month payment plan that allows customers to pay their current bills, plus 1/6 of their arrears. The timing of this option during the non-heating season is beneficial to customers, as it is likely that paying their current bill plus 1/6 of their arrears would be lesser than the standard budget amount, which represents an average 12 month usage.

Commercial customers with arrears of more than $90 and less than $600 are also being offered a 6 month payment plan. This payment plan option is intended for customers who are normally not payment troubled and financial information is not required for enrollment in this plan.

Q. How do customers enroll in the alternative payment plans?

A. Customers can enroll in these alternative payment plans via Columbia's website or by contacting our customer call center. We have shared this information via bill messaging, website notices, reminder letters, and customer representatives at the Company's Customer Care Centers, along with the Company proactively reaching out to individual customers by phone. To date, 225 residential customers and 33 commercial customers have signed up for this payment plan.

C. <u>Universal Services Programs and Other Assistance Programs:</u>

Q. Is the Company currently removing customers from the Customer Assistance Program ("CAP") for non-payment or failure to verify their incomes?

A. No. Columbia is not removing any customers from CAP for missed CAP payments. While CAP participants are subject to removal from CAP if they do not verify their income eligibility annually, Columbia is currently forgoing removal from CAP on that basis. Currently, Columbia is not removing customers from its CAP unless they send us information verifying they are no longer eligible, they move from our service territory, or they request to be removed in writing.

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 as a result of the pandemic:

- As noted above, customers are not being removed from CAP.
- The additional $600 per week from Unemployment Compensation 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 existing 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 available to customers who are at or below 200% of poverty and have arrears. In response to hardship caused by 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 they have arrears on their account.

Q. Are there other assistance programs that Columbia developed as a result of the COVID 19 pandemic?

A. Yes. On April 24, 2020, concomitant with this proceeding, the Company filed a petition for approval of a temporary customer grant program called the Reduced Income Grant Program ("RIGP") for residential customers who are not eligible for Columbia's low income customer programs. The RIGP 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.

Q. OSBA Witness Knecht asserts that the Company is not asking the shareholders to contribute to the impacts of COVID 19. Is this statement accurate?

A. No. In addition to the Company delaying the filing of this base rate proceeding by five weeks, the Company has made changes to Hardship Fund eligibility and waived late fees for past due balances. I will discuss each item individually below.

Q. Was this case filed in accordance with the Notice of Anticipated Filing of a General Rate Increase made by the Company on February 19, 2020?

A. No. On February 19, 2020, the Company filed a Notice of Anticipated Filing of a General Rate Increase as required by the Pennsylvania Public Utility Commission's ("Commission") regulation at 52 Pa. Code § 53.45 and Section 69.402. The notice was filed in advance of the Company's case originally scheduled to be filed on March 20, 2020. Had the case been filed on March 20, 2020, the Company was proposing rates to go into effect on December 19, 2020.

It was during this week of March 20, 2020 that the pandemic escalated to the point where businesses were ordered to close their doors, resulting in significant impact to the economy. The company opted to postpone the filing of the rate case, and the case was subsequently filed on April 24, 2020. New rates were scheduled to go into effect on January 23, 2021.

Q. What was the revenue impact as a result of delaying the filing of the case?

A. Based upon Columbia's updated revenue requirement deficiency of $100,366,797, which is presented by witness Miller on Exhibit KKM-1R**,** the revenue impact of delaying the rate case filing is approximately $16.1M.

Q. Please describe the Hardship Fund, including the shareholder contribution to funding and changes to eligibility requirements the Company has implemented during the pandemic.

A. The Hardship Funds is a fund of last resort that provides grants to customer to maintain or restore their services, and is partially funded by $150,000 of shareholder dollars. Further, the Company has relaxed Hardship Fund application eligibility requirements during this time. To be eligible to receive hardship funds, customers no longer have to make a minimum payment, active CAP customers may receive Hardships funds, and the Hardship Fund is now open to all customers who have arrears. The Hardship Fund currently has $747,000 available for customer assistance.

D.* Waiver of Fees*:

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: Currently, the Company has voluntarily waived late payment fees. Since the beginning of the pandemic, late fees in excess of $700,000 have been incurred and will not be billed to 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% of the Federal Poverty Income Guidelines ("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. Many 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. Completion of Bare Steel Replacement Program/Municipal Relations Strategy/Restoration Cost Audit of the 10 Largest Projects

Q. Please summarize the topics of I &E Witness Niambele's testimony you will be addressing.

A. I will first address witness Niambele's concern that Columbia will not meet the stated date in its Long Term Infrastructure Improvement Plan ("LTIIP") of 2029 for replacement of bare steel and cast iron on its system, then respond to his recommendation that Columbia perform an audit of the 10 projects with the largest restoration costs, as part of an effort to reduce municipal restoration costs.

A. Completion of Bare Steel and Cast Iron Replacement by 2029

Q. What is witness Niambele's concern regarding the replacement of bare steel and cast iron pipe on the Company's system by 2029?

A. Witness Niambele expressed a concern that the Company's target to replace bare steel and cast iron on its system by 2029 will not be met. He bases his conclusion on a straight line, historical average approach of how many miles of pipe the Company has to replace between now and 2029 in order to meet that target.

Q. Is this a reasonable basis by which to conclude the Company will not meet the 2029 date?

A. No. As Company witness Kitchell explains in detail in his rebuttal testimony (Columbia Statement 14-R), each project presents unique issues which impact the mileage that the Company replaces each year, rendering the notion of a straight line assumption invalid.

Q. Is this proceeding the correct place to evaluate Columbia's 2029 target to replace the bare steel and cast iron on its system?

A. No. The appropriate proceeding in which to address this topic is within the confines of Company's Long Term Infrastructure Improvement Program ("LTIIP"). In this base rate proceeding, the focus is on the Company's projected capital spend in the context of setting base rates for the 2021 Fully Projected Future Test Year. I would further note that the Commission staff notified the Company on June 5, 2020 that the Commission will complete its mid-plan review of Columbia's LTIIP this year at Docket No. M-2020-3019712. This review will provide the Commission and other interested parties the opportunity to assess the Company's current plan, as well as the Company's target of 2029 to complete its replacement of cast iron and bare steel on its system.

Q. Please describe the Company's current LTIIP timing.

A. The Company is presently midway through its current Commission-approved LTIIP, which is in effect from 2018-2022. As noted by Witness Niambele, after missing its projected replacement target in 2018, Columbia has successfully managed its program to be back on track for its targeted replacements for the current LTIIP.

Q. Did the issue of bare steel and cast iron pipe replacement by 2029 come up in the Company's Management and Operations Audit conducted by the Pennsylvania Public Utility Commission in 2019?

A. Yes, it did. As addressed above, this issue is best suited for the Company's LTIIP proceeding, however, at pages 43-44 of the Management and Operations Audit Report Docket No. D-2019-3011582, acknowledged by the Commission on July 16, 2020, the Bureau of Audits states the following:

> 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.

Q. Has the Company made major modifications in the past to its LTIIP?

A. Yes. On May 5, 2017, the Company simultaneously filed a petition for Commission approval of a major modification to its then-existing LTIIP at Docket No. P-2012-2338282 as well as its second LTIIP at Docket No. P-2017-2602917. The major modification was required as a result of an increase in main replacement from 500,000 feet to 680,000, which resulted in a cost increase of more than 20% in the original LTIIP (from $116.9 million to $230 million) and therefore, Columbia sought Commission approval of that modification under 52 Pa. Code § 121.5(a). Both petitions were approved and dockets closed on September 21, 2017.

Q. Please summarize your response to Witness Niambele's concerns about the 2029 date of completion for the Company's bare steel and cost iron replacement being in jeopardy.

A. Even if the date were in jeopardy as Witness Niambele asserts, a base rate proceeding is not the appropriate proceeding in which to address this issue. Rather, it should be addressed in the LTIIP. Further, Columbia has shown that in the event a major modification to the LTIIP is necessary, the plan will be modified as required by regulation.

B. Municipal Relations Strategy/Restoration Cost Audit of the 10 Largest Projects

Q. What are witness Niambele's concerns and recommendations regarding paving and restoration costs?

A. Witness Niambele is concerned that municipal restoration requirements are driving up overall replacement costs, and that as a result of increasing restoration costs, fewer miles of priority pipe are replaced. Further, Witness Niambele recommends that Columbia develop a cost reduction plan to be submitted to the Pipeline Safety Division of I&E within 60 days of the final order in this proceeding. Included as part of this plan is a reduction of restoration costs, with the recommendation that the Company review the 10 largest projects each year to see if there are any unnecessary or avoidable costs, including excessive restoration costs. As addressed by Columbia witness Kitchell in Columbia Statement 14-R, the Company does not support Witness Niambele's recommendation that it prepare and file a cost reduction plan due to the numerous proactive measures already being done to mitigate rising municipal costs. However, I will address the recommendation regarding the audit of the 10 largest projects.

Q. Do you agree with Witness Niambele's concerns that municipal restoration requirements, if left unchecked, will drive up the cost of the Company's pipeline replacement project?

A. Yes. As the Company's replacement program has matured, we have seen an increase in costs related to more stringent municipal requirements, not just related to restoration and paving, but for costs such as flagging and permitting as well.

Q. What is Columbia's plan to address these ongoing municipal challenges?

A. This issue is not new to Columbia, and has been addressed in the Company's base rate proceedings since 2012. The Company shares witness Niambele's concern that increasing costs associated with municipal restoration and permitting requirements will result in fewer miles of cast iron and bare steel pipe from being replaced each year. To address this issue, Columbia has implemented measures to proactively address municipal requirements, which are discussed in detail in Columbia witness Kitchell's direct and rebuttal testimony at Columbia Statement 14-R. It is noteworthy that, in approving Columbia's petition for approval of major modification of its first LTIIP, which I discussed above, the Commission addressed the issue of the cost impact of local government requirements. In its Opinion and Order approving Columbia's major modification, the Commission observed that:

> Columbia provided examples of where the magnitude of restoration costs increased in certain portions of their service territory, based on projects completed both before and after the new ordinances or requirements were put in place. Based on the data provided, it

> appears there are significant cost increases associated changes in municipal restoration requirements. The changes vary in each municipality, with some changes resulting in only relatively modest increases in restoration costs of 20% to 30%, while others increased significantly by 50% to 80%. In some instances, the restoration costs per mile more than doubled.
>
> Based on this information provided by Columbia, it appears that these changing restoration requirements are a significant driver of Columbia's cost increases. It is likely that a portion of Columbia's 97% cost increase in 2017 over its original projections is attributable to these restoration cost increases. Columbia has demonstrated that it has put measures in place in an attempt to control these costs and restoration requirement changes when possible. However, the Company cannot prevent a local government body or official from enacting ordinances as they see fit to govern their township, borough, or city. While Columbia is attempting to do as much as it can to mitigate these costs, the Commission recognizes that such costs are, to some extent, out of the Company's control.[1]

Q. Has Columbia's proactive approach been successful?

A. Yes, it has been. In addition to the examples listed in Columbia witness Kitchell's direct testimony, further examples were provided in the Company's responses to data requests I&E GS-002 and OSBA 1-003. These data request responses have been attached to my rebuttal testimony as AST Exhibit 2-R and AST Exhibit 3-R, respectively.

Q. Why did Columbia choose to take this type of approach?

A. As I noted above, this issue is not new to Columbia or to the Company's rate case proceedings. In 2014, as part of the Commission-approved settlement at Docket

[1] Docket Nos. P-2012-2338282; P-2017-2602917, Opinion and Order entered September 21,2017, p. 8

No. R-2014-2406274, Columbia agreed to undertake an audit of the 10 largest construction projects completed that year in order to identify and assess the costs incurred in excess of the Pennsylvania Department of Transportation restoration standards for paving, sidewalk repair and permitting fees. A copy of this audit has been attached to my rebuttal testimony as AST Exhibit 5-R. The audit represented a historic lookback of infrastructure replacement costs. As a result of this audit, Columbia concluded that the most effective way to manage costs related to municipal ordinances was to address those costs proactively and developed a cross functional team and process for this purpose, as described in Columbia witness Kitchell's direct testimony (Columbia Statement No. 14).

Q. Was the 2012 audit useful in assisting the Company's efforts to mitigate increasing costs associated with municipal requirements?

A. No. The 2012 audit did not reveal any new information; rather, it independently confirmed several key factors known to the Company to significantly impact restoration costs. Key factors known to management, and identified in the audit, are as follows:

- Lack of uniform restoration requirements across the Commonwealth makes it difficult to compare restoration efforts across projects, as each may be subject to different specifications.
- Many townships and boroughs either have had or have recently established ordinances with their own restoration specifications as the nature of the

Commonwealth structure permits them to do so. Such ordinances have more expansive restoration requirements, and the Company is compelled by these laws to comply with documented specifications.

- Sidewalks and curbs in long-established cities or towns where age and condition factors warrant pipe replacement are often in significant disrepair or nearly nonexistent. In these situations, if a sidewalk is disturbed, or the installation of related service lines leads to circumstances requiring the mill and overlay of the road, the Company must also install curbs and/or sidewalks to meet required specifications.
- Federal Laws, specifically the Americans with Disabilities Act (ADA), require restoration of roads and walkways to a level compliant with current ADA specifications. The disruption of one ADA ramp often necessitates the upgrade of the adjacent ramp and, in some cases, all four corners of an intersection may require upgrading to meet current federal standards.
- The Company collaborates with other entities to look for restoration cost sharing opportunities for restoration costs.

Q. What was the most consistent characteristic of the projects reviewed during the audit?

A. The 10 projects representing the largest capital expenditures were projects that were expensive for reasons not related to municipal requirements, but instead were expensive due to the nature of the project. That is, a number of the projects audited in 2012 were on the list due to the expense associated with stream or river crossings, or involved large stretches of hard surface construction. Therefore, the 2012 audit, while well intended, did not provide any new insights for the Company to implement beyond its already robust response to these costs. In addition, the 2012 audit was time consuming and did not yield the desired results of an opportunity for costs savings. Further, Columbia has shown that the current, proactive approach being utilized is generating results related to cost savings. Based upon this experience, Columbia does not support another review of the Company's ten largest projects, as proposed by I&E witness Niambele.

IV. Universal Services Costs Allocation to Commercial and Industrial Customers

Q. Please summarize OCA Witness Colton's and CAUSE PA Witness Miller's positions that the costs for the Company's Universal Service Programs ("USP") should be borne by all rate classes.

A. Both witnesses assert that programs such as the Pennsylvania universal service programs address a societal-wide problem that is not limited to the residential customer class. Further, they assert problems that are related to unaffordable home energy are not "caused" by the residential class, nor do the Company's universal service programs deliver benefits that are limited to the residential class. Based upon these contentions, Mr. Colton and Mr. Miller contend that the costs of those programs should be allocated and spread over all customer classes.

Q. Does Columbia support Witness Colton's and Witness Miller's recommendation that USP costs should be borne by all customer classes and not just the residential class?

A. No. Columbia is a strong supporter of the customer assistance programs it offers to its residential customers, as these programs provide necessary help to customers that rely on gas service to heat their homes and provide for their families. However, as held by the Commission in numerous proceedings, the costs of these programs should be funded only by the residential class.[2] While the Commission's amended CAP Policy Statement provides that parties to base rate proceedings may raise the issue of recovery of Universal Service costs, and that no rate class should be routinely exempt from universal service obligations[3], Columbia does not support its commercial and industrial customers paying for these programs when only residential customers are eligible to participate in these programs. Further, Columbia is opposed to placing costs on its commercial and industrial customers which are not placed on the commercial and industrial customers of other utilities in the Commonwealth.

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[2] These proceedings include: PPL Electric Utilities Corporation at Docket No. R-00049255; Valley Energy, Inc. at Docket No. R-00049345; Equitable Gas Company at Docket No. P-00052192; PPL Gas Utilities Corporation at Docket No. R-00061398 and Metropolitan Edison Company and Pennsylvania Electric Company at Docket Nos. R-00061366 and R-00061367. The Commission's decision in the Met-Ed and Pennsylvania Electric Company to not allocate universal service costs to non-residential rate classes was affirmed by the Pennsylvania Commonwealth Court. *Popowsky v. Pennsylvania Public Utility Commission*, 960 A.2d. 189.

[3] 52 Pa. Code § 69.266.

Q. Please explain.

A. While both witnesses indicate in their testimony that multiple other states charge costs of universal services across all rate classes, currently in the Commonwealth of Pennsylvania, the vast majority of residential customers bear the cost of USPs. To single out Columbia's commercial and industrial customers in the context of a base rate proceeding is inappropriate, as other similar customers, including potential competitors for Columbia's industrial and commercial customers, are not being required to pay for these programs. Further, requiring only Columbia's large commercial and industrial customers to contribute to these programs, but not customers of other western Pennsylvania utilities or customers who have the ability to shift to other sources of gas supply (such as interstate pipelines or their own gas wells), could prompt the Company's customers to seek to bypass Columbia. For these reasons, Columbia believes that a general proceeding on this issue, and not a single utility's rate case, is the appropriate forum for this issue. In addition, customers who are currently under flexed or negotiated rates would need to be excluded from any allocation of these costs, or the base rate revenues projected for these discounted rate customers would need to be reduced as an offset to these costs. I further observe that Columbia's USP costs are recovered through its Rider USP. No party has challenged the continued recovery of these costs through a reconciled rider mechanism, and this should not change regardless of what customer classes are to pay these costs. I also note that, as explained by Columbia witness Bell (Columbia Statement Nos. 3 and 3-R), based upon the Company's preferred average cost allocation study, the Residential class, inclusive of USP Rider revenues and costs, is currently paying below a system average return, and should not be paying less than its class costs by shifting recovery to other classes.

Q. Do you have additional comments on this issue?

A. Yes. It is important to recall why these programs were developed. USPs were created to reduce overall costs related to customer arrearages and customer collection costs to residential rate payers by reducing residential customer arrearages. The residential class is the class that benefits from the reduction in such arrearages and collection costs, and should therefore be the customer class that bears the cost of these programs.

Q. Do the commercial and industrial customer classes cause the Company to incur any costs in relation to residential customer arrearages?

A. No, they do not.

Q. Do the commercial and industrial customer classes receive any reduction in costs as a result of reduced customer arrearages?

A. No, they do not.

Q. Do you have any comment regarding the assertions of Witness Colton and Witness Miller that USPs costs should be charged to commercial and industrial customers as a "public good" or "public purpose"?

A. Yes. These concepts divorce revenue allocation and rate design from cost incurrence and cost allocation principles. It looks outside the ratemaking process to arbitrarily conclude that a cost that is caused by one class should be shifted to other classes.

Q. Please summarize the Company's position on Witness Colton and Witness Miller's conclusion that commercial and industrial customers should bear the costs of USPs.

A. Absent all commercial and industrial customers in all industries across the Commonwealth sharing the cost of USPs, Witness Colton's and Witness Miller's proposal for Columbia's commercial and industrial customers to bear costs related to USP's is discriminatory in nature, is not in compliance with net neutrality requirements in the Natural Gas Choice and Competition Act (See, 66 Pa. C.S. §2203(5)). Further, USPs were not designed to impact and benefit commercial and industrial customers, and therefore, those customer classes should not bear any cost related to these programs.

V. Management Adder

Q. What is the purpose of Columbia's proposed adjustment of 20 basis points to the return on equity for management performance?

A. Columbia's counsel has advised me, and from my time serving as legal counsel to Columbia and other Pennsylvania utilities, I am aware that, under Pennsylvania law, the Commission shall consider the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates. Title 66, Section 523 further provides that the Commission "shall give effect to this section by making such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate." In my adopted direct testimony, as well as in the testimony of other Columbia witnesses, we have offered examples of the "efficiency, effectiveness and adequacy of service" to provide the Commission evidence upon which to make such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate.

Q. Please summarize the positions of the parties that are challenging the appropriateness of the 20 basis point management performance premium.

A. OCA Witness O'Donnell maintains that there is no evidence in the record to show that the Company's management has demonstrated exemplary performance in the categories of leak reduction, damage reduction, emergency response time, and consumer report evaluations since the Company's current base rates were implemented in December 2018. Witness O'Donnell also states current economic conditions related to COVID 19 do not warrant an increase in return related to performance. OCA Witness Colton believes that the Company's collection costs are too high, and that the Company has a high level of arrearages and disconnection rates, while having low reconnection rates.

I&E Witness Keller states that, while the Company touts its Management Audit scores against other LDCs, room for improvement still exists and points to several findings in the Company's most recent Management and Performance Audit at Docket No. D-2019-3011582. He specifically points to the finding of high customer service representative turnover, stating that customer service is an area in which the Company is in complete and direct control, and that awarding management effectiveness points to the Company management will cost the customer for service that can and should be improved.

Q. Do you agree with Witness O'Donnell that Columbia has not shown exemplary performance in the categories of leak reduction, damage reduction, emergency response time and consumer report evaluations since the Company's new base rate were implemented in December 2018?

A. No, I do not. The data provided in Columbia Statement No. 1, pages 19-21 clearly states otherwise. The number of damages per locates have gone down, and the average response time to emergencies continues to decrease. Although there was an increase in the number of grade two leaks found from 2018-2019, there was a corresponding increase in the number of leaks cleared.

Q. Do you agree with Witness Colton's testimony that Columbia's performance on collections is less then exemplary?

A. No. Witness Colton concludes that the Company's amount of arrearages and number of customers in arrears compared to other Pennsylvania utilities is "not the worst, but not exemplary". However, Witness Colton's own testimony citing the PUC's collection report data provided annually, supports just the opposite conclusion, as I will address below.

Q. What is the basis upon which Witness Colton makes this conclusion?

A. Witness Colton's conclusion is fundamentally flawed in that it is based on data that has not been adjusted to position the utilities at a comparable starting point to make such a determination.

Q. How does not adjusting the data to a comparable starting point impact the validity of Witness Colton's conclusion regarding the Company's performance on collections?

A. Pennsylvania utilities vary greatly in relation to factors that impact collection information. For example, the number of customers across utilities in Pennsylvania range from 146,000 on the low end to 1.5 million customers on the high end, while revenues range from $165 million to $2.5 Billion. Comparing data that has not been adjusted to reflect an appropriate comparison of utilities results in conclusions that are not accurate. Had Witness Colton utilized comparative data available to him, that data would have shown that the Company performs well relative to its peers.

Q. Did Witness Colton have access to information that provided collections data adjusted to represent the size of individual utilities for

comparative purposes?

A. Yes, he did. As Mr. Colton notes, the data contained in the table on page 79 of his direct testimony is an excerpt of information taken from the Commission's annual reports on Chapter 14 implementation. I have attached Exhibit AST-5R to my rebuttal testimony, which contains 2019 Collections Data in its entirety, meaning it includes both adjusted and unadjusted collections information. Further, within Exhibit AST-5R, I have provided information showing how the Company ranks relative to its peers when utilizing the proper information for comparison. Given that Witness Colton had access to all the information when preparing his analysis of the Company's collections performance, it appears that he selectively chose to present the information that did not reflect the true nature of how collections should be evaluated.

Q. Please explain the differences between the comparisons of Pennsylvania utilities provided by Witness Colton and adjusted comparisons provided in Exhibit AST-5R.

A. Had Witness Colton utilized adjusted data that was readily accessible to him in preparing his analysis, the following would have been noted:

- Columbia has the lowest percentage of customers in debt. See Exhibit AST-5R, page 2, Column N.
- The Company has the highest percentage of debt on payment agreements than any other Pennsylvania utility as indicated in Exhibit AST-5R, page 2,

Column I. This clearly demonstrates the Company is actively and effectively working with customers that are behind and making payment arrangements, a practice fully supported and encouraged by the Commission.

- Exhibit AST-5R, page 3, Column D demonstrates the Company has the lowest termination per customer rate of any utility, as opposed to Witness Colton's assertion that the Company's termination counts are the third highest of all utilities.

Q. Are there any other relevant metrics that demonstrate the Company's collections performance?

A. Yes. Per Exhibit AST -5R, page 1, the Company's gross residential write off ratio was the lowest of all gas utilities and the third lowest of all Pennsylvania. In addition, the Company's recovery rate was the highest of all gas utilities and second highest overall of all Pennsylvania utilities, as shown Exhibit AST-5R, page 1, Column J.

Q. What is your response to Witness Keller's position regarding employee turnover?

A. Turnover at the Smithfield Customer Contact Center (CCC) is an issue that the Company is consistently striving to improve. The Company has taken the following actions to address the turnover issue at the CCC:

- Partnered with a third party consultant with expertise in employee retention and engagement to reinforce positive employee engagement and reduce attrition;

- Employee Roundtable Meetings and Safety Committee meetings are held monthly;
- Formation of an Inclusion & Diversity Committee;
- Regular Employee Engagement Surveys are conducted, followed up with action planning sessions and focus group meetings, and;
- Continuous improvement of processes and technology that our agents use to help service our customers.

Although COVID has brought some unique and unexpected challenges in 2020, employee retention continues to be a primary focus at the CCC.

Q. Would you like to address other findings in the recently released Management and Operations Audit Report?

A. Yes. While Witness Keller seeks to focus on a few findings in the recently completed audit, he elected to not address the positive outcomes in the report. Indeed, the audit released by the Commission identified that "none of the functional areas examined during the audit require major or significant improvement." Of the eleven broad categories thoroughly investigated by the Commission's audit staff, four categories resulted in no findings or recommendations, while three categories had one finding and an associated recommendation.

Specifically, Witness Keller fails to recognize that the Commission made no findings relative to the Company's Gas Operations, which evaluates the day-to-day operations of Columbia, and how the Company manages to provide safe and reliable service to its customers. While Witness Keller may not view the lack of any findings worth noting, Columbia views the lack of any recommendations on the key aspect of our operations as significant. First and foremost, Columbia is a natural gas distribution company, and the fact no findings were made after an extensive Commission audit of operations is a source of great pride for Columbia and our employees.

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Flex Rates

Q. Please summarize the issues you will be addressing regarding flex rates.

A. I will address OSBA witness Knecht's assertion that Columbia does not provide adequate justification for customers paying less than the full tariff rate and I&E Witness Cline's request for Columbia to provide a competitive alternative analysis for customers whose alternative fuel source has not been verified for a period of 10 years or more when Columbia files its next base rate case. I will also address Columbia Industrial Intervenor (CII) Witness Frank Plank's position regarding Columbia's unwillingness to offer Knouse Foods a flexible rate contract.

Q. OSBA Witness Knecht states that the Company has not presented sufficient justification for granting discounted rates to flex customers. Does he have the information needed now?

A. I am advised by legal counsel that Witness Knecht requested, and was granted, access to highly confidential information on July 10, 2020, the date in which the Company received his signed confidentiality agreement. Customer information is highly confidential, and would not have been provided to any witness through the discovery process absent a request for access to highly confidential information.

Q. Was the request for information regarding customers not paying the full tariff rate made throughout the initial discovery period?

A. Yes. At least three requests were made for this information. The first request was in Confidential I and E RS—06, sent to parties, including Witness Knecht, on June 15, 2020. Confidential OCA 1-34, was sent to parties, including witness Knecht on June 25, 2020 and OSBA 1-29 was sent to parties, including Witness Knecht, on July 9, 2020. Columbia concedes that while not all data requests may have been submitted timely and in accordance with the procedural schedule, there was a period of 19 days between the time the last discovery request with Flex customer information was sent to parties and the time direct testimony was due from parties on Tuesday, July 28, 2020.

Q. Do you agree with Witness Cline's recommendation for Columbia to provide a competitive alternative analysis for customers whose

alternative fuel source has not been verified for a period of 10 years or more when Columbia files its next base rate case?

A. No. Columbia agreed to provide updated competitive alternative analyses for the six flex-rate customers that had not had their alternative supply verified since 2008 and one customer that had not had their alternative supply verified since 2010 as part of settlement from Docket R-2018-2647577, and Columbia has complied with this commitment. However, Columbia does not believe this analysis is necessary going forward. The analyses performed as part of the settlement from Docket R-2018-2647577 were on agreements up for renegotiation, and a competitive alternative evaluation was to be done as part of Columbia's normal renegotiation process.

Q. Do flex agreements typically extend beyond 10 years?

A. No. It is the Company's preference to enter into agreements that are less than 10 years. While there are a limited number of customers whose agreements are longer, those agreements are based on the unique circumstances of the customer, with the economic analysis for the bypass performed based on the market conditions at the time the contract is entered into. Witness Cline correctly identifies in his testimony that facts and circumstances may change, however, absent specific contractual agreements to update the contract, the rate will remain the same throughout the duration of the contract as facts and circumstances dictate at the time the agreement was entered into. For example, if

I obtained a fixed 30 year mortgage at the time when the market supported a 3% interest rate, the lender would not be permitted to raise that rate in the future, even if circumstances warranted a different rate. Any analysis performed would not impact Columbia's ability to change the terms of the contract, and therefore, such an analysis is not necessary.

Q. What are the tariff requirements Knouse Foods would have to meet in order to be eligible for a flexible rate contract?

A. Supplement 221 of Tariff Gas – Pa PUC No. 9 requires a customer to submit a sworn affidavit that a lower rate is required to meet competition from an alternate fuel. In the sworn affidavit submitted by the customer, the following must be documented:

(a) The customer has alternate fuel capability in place and operable or would otherwise construct facilities to obtain gas service from an alternate source;

(b) The quantity of natural gas transported by the Company which would be displaced by operation of the alternate fuel capability;

(c) The burner tip cost in therm equivalent of the customer's alternate fuel; and,

(d) If the customer has an agreement with a producer for purchase of gas, the customer must verify that it has exercised all contractual rights available to the customer, including price redetermination, marketability or market reopener provisions, to reduce the city gate price of natural gas delivered to the Company for redelivery to the customer, and that the customer has the right to cease purchases under the agreement. Upon request by the Company customer agrees to submit a true copy of the currently effective agreement or agreements between customer and producer(s) for purchase of natural gas quantities delivered to the Company's city gate for redelivery to the customer. If the customer does not have an outstanding contract with a producer, the customer must verify that the customer is unable to purchase gas at a price, including cost of delivery by Columbia that is equal to the cost of alternative fuel.

In addition to the above, Columbia also requires the customer provide the "all-in" burner tip price in its sworn affidavit for Columbia to evaluate whether a flexed rate should be offered to the customer. Columbia shall undertake its own review of the facts surrounding the customer's competitive alternatives to assess the reasonableness of the asserted price. If Columbia has questions concerning the reasonableness of the asserted price, Columbia reserves the right to verify the accuracy of statements included in this affidavit. These provision was part of the settlement at Docket R-2010-2215623. A copy of this settlement has been attached at AST Exhibit 11-R.

Q. Has Knouse Foods been able to provide a sworn affidavit with all of the requirements per the tariff?

A. No, they have not. Per Witness Plank's testimony, it appears the alternate source of fuel supporting the flexible rate agreement has increased in price and is no longer a competitive alternative to natural gas.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Amy E. Hirakis
Senior Counsel
Legal Department

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Harrisburg, PA 17102

Office: 717.210.9625
ahirakis@nisource.com

June 15, 2020

VIA E-File

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

Re: COVID-19 Customer Service, Billing, and Public Outreach Provisions
Request for Utility Information
Docket No. M-2020-3020055

Dear Secretary Chiavetta:

Enclosed for filing please find one (1) original copy of Columbia Gas of Pennsylvania, Inc.'s Response to the Secretarial Letter Dated May 29, 2020.

If you have questions, please call me at 717-210-9625 or e-mail me at ahirakis@nisource.com.

Thank you for your attention to this matter.

Very truly yours,

Amy E. Hirakis

Amy E. Hirakis

Enclosures

cc: Sarah Dewey; Bureau of Consumer Services (sdewey@pa.gov)
Tom Charles; Office of Communications (thcharles@pa.gov)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

COVID-19 Customer Service, Billing, and	:
Public Outreach Provisions Request	: Docket No. M-2020-3020055
for Utility Information	:

Columbia Gas of Pennsylvania, Inc. Response to the Secretarial Letter Dated May 29, 2020

In response to the Secretarial Letter dated May 29, 2020, Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") submits the following information:

I. COVID-19 Utility Consumer Service and Billing Policies and Procedures

Describe and report efforts to support customers through initiatives in customer service and billing policies and procedures in response to the COVID-19 pandemic and the ensuing recovery period. Explain how these initiatives differ from normal operations:

Company Response:

The Company has adapted its policies and procedures, as well as implemented additional initiatives, in an attempt to assist all customers affected by the pandemic. Many of these actions are included in the content below. However, as a summary of all efforts, the Company has:

- Suspended all termination activity and delayed all late payment fees
- Relaxed reconnection guidelines on restoration quotes to assist customers needing hot water and heat during the pandemic
- Initiated Senior Wellness check phone calls to customers over 70 years old whose records indicate live alone
- Relaxed Hardship Fund and CAP guidelines to reduce barriers to enrollment
- Ceased all company removals from the CAP program including non- payment, failure to re-verify income and failure to cooperate with weatherization.
- Increased communication about operations, payment assistance and programs including the LIHEAP recovery CRISIS program
- Offered additional payment plan options for those customers seeking a non-budget plus payment plan

Termination of Utility Service:

- *After the Commission's Emergency Order on Terminations at Docket No. M-2020-3019244 ends, how soon does the utility plan to begin termination of service for nonpayment?*
    - *How does the utility plan to implement terminations and will it start the process with new termination notices?*

Company Response:

Columbia, in recognition of the critical needs of its customers during the COVID-19 pandemic emergency, has voluntarily developed a two-phased plan for collection activity. The first phase includes sending reminder letters to customers advising of account balances, offering flexible payment arrangements, and referrals to energy assistance programs. The second phase, which is expected to occur no earlier than September 4, 2020, the Company will resume termination notices with the intent to shut off for nonpayment starting with a new 10 day termination notice.

- *Broken out by customer class, how many customer accounts may be subject to termination if the Commission's Emergency Order prohibiting terminations is rescinded and how does this number compare to the same time period in 2019?*
    - *Provide these figures for all utility confirmed low-income customers, including Lifeline and Customer Assistance Program (CAP) customers.*
    - *Provide future projections if available.*

Company Response:

Columbia is not sending out termination notices to customers at this time and therefore cannot quantify how many or which customers would have received a termination notice to make a comparison to the same time period in 2019. Further, due to the credit delays Columbia has placed on all accounts during the pandemic, the traditional report that the Company uses to report arrears on accounts has been impacted. As a result, the Company is unable to compare numbers using the arrears reported on the USRR report in 2019 at this time. The Company can provide a snapshot of all customers who have a balance on their account. However, the Company is unable to disaggregate by low income and CAP. As of May 31, 2019, there were 91,264 accounts with arrears totaling $26,361,897. As of May 31, 2020, there were 71,570 with arrears totaling $ 28,275,438. The number of customers in debt has decreased, however the average arrears has increased by 7%.

The Company recorded 8,491 CAP customers that were billed in a delinquent status in May, 2019. In May, 2020, the Company billed 8,923 CAP customers in a delinquent status. However, a deeper look at the 8,923 revealed that 3,447 customers owed less than one CAP payment and would not receive a termination notice under non-moratorium circumstances. Rather, 5,476 customers would be in jeopardy of termination under those conditions. The Company is unable to provide the same information for CAP customers from 2019

The Company is not able to predict the number of customers that will be in arrears in the future.

- *Is the utility currently assessing a "reconnection fee" to restore service? If yes, how is the fee billed and/or collected? Will this fee apply to customers reconnected under the Commission's Emergency Order that wish to pay any arrearage and stay connected?*

<u>Company Response</u>:

Columbia's normal policy is to waive the $24 reconnect fee for customers identified as having a household income of less than 150% of the Federal Poverty Income Guidelines. During the COVID-19 pandemic, customers who contacted the Company to have service restored and were identified as payment troubled also had their reconnect fees waived. Columbia restored 41 accounts from March 13 through June 4, 2020. Of those 41 accounts, 23 customer accounts had the reconnect fee waived. The Company requires the reconnect fee prior to connection; however, the Company has used discretion to bill the reconnect fee on the first bill after reconnection, if the customer expresses a hardship with an upfront payment.

Universal Service Programs:

- *Is the utility currently removing customers from CAP for non-payment or failure to recertify?*

<u>Company Response</u>:

No. Columbia is not removing any customers from CAP unless they send us information verifying they are no longer eligible, they move from our service territory or they request to be removed in writing.

- *What are the utility's current Hardship Fund payment requirements to qualify low-income customers for grants (e.g., waiving payment history "good faith payment", or CAP participation criteria) and have these requirements been revised due to the pandemic?*

<u>Company Response</u>:

The Company has made the following changes to existing Hardship Fund guidelines in order to assist customers through the pandemic:

– Waiver of the requirement of a sincere effort of payment. No payment is required.

- All low income customers are eligible regardless of CAP status so long as they have arrears on their account.

The Company has made the following changes to the CAP program as a result of the pandemic:
- Customers are not being removed from CAP, as stated above.
- The additional $600 per week from Unemployment Compensation is not being counted as income since the income is short term.
- Any "stimulus" income is not being counted as income.
- Proof of income is not required at this time for CAP for those unable to provide income.

Further, the Company is actively promoting the LIHEAP Recovery CRISIS program and is participating in the Department of Human Services Utility File Transfer component. The Company is making outbound calls to eligible previous LIHEAP recipients to obtain permission to apply to the program on their behalf. In addition, Columbia is sending out applications to customers upon request.

Columbia Gas LIURP was closed on March 16th and reopened on June 8th for in home appointments

Other Assistance Initiatives:

- *Describe any policies/procedures the utility has updated to assist customers impacted by the pandemic that go beyond provisions in PUC policies or regulations.*

<u>Company Response</u>:

In addition to Columbia's normal budget plus payment plan offered to its customers based on financial information and household size, Columbia has also determined to provide an alternative payment plan option as a result of the COVID -19 Pandemic. For both Residential and Commercial customers with arrears of more than $90 and less than $600, a 6 month payment plan is negotiated with customers. This payment plan option is intended for customers who are normally not payment troubled and financial information is not required. Customers can enroll in this alternative payment plan via Columbia's website or by contacting the Company's call center as of May 22, 2020. This information will be delivered through bill messaging, website notices, reminder letters, and customer representatives at the company's Customer Care Centers, along with the Company proactively reaching out to individual customers by phone.

- *Describe any proposed or anticipated changes in programs/practices/policies to assist customers impacted by the pandemic after the Governor's Emergency*

Proclamation and the PUC Emergency Order on Terminations expire or are lifted.

Company Response:

In addition to the modified collections activities described above, the Company will continue to promote programs to all residential customers, and do targeted outreach for specific income eligible programs, such as outbound calling to LIHEAP Recovery CRISIS program eligible customers. Examples are included below.

The Company has also designed a temporary customer grant program called the Reduced Income Grant Program ("RIGP") for residential customers who are not eligible for Columbia's low income customer programs. The RIGP would provide customers with grants up to $400 to reduce arrears and offer credit counseling. On April 24, 2020, the Company filed a petition with the Commission seeking approval of the Company's proposed funding source for the RIGP and this petition is currently pending before the Commission at Docket No. P-2020-3019578.

II. Consumer Education and Outreach

- *Descriptions and/or examples of how the utilities are educating their customers about their rights and responsibilities, assistance programs, energy efficiency and conservation, and/or COVID-19 recovery.*

Company Response:

Columbia is using all available resources to educate customers regarding the Company's current collection practices, available assistance programs and COVID-19 recovery. Examples include:

- Social media posts on Facebook & Twitter;
- Targeted outbound calls for 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;
- Customer Newsletter.

Please see Attachment A for samples of all materials.

- *Efforts to reach all utility consumers with information about income-qualified programs and resources and about non-income-qualified educational services, tools, and resources.*

<u>Company Response</u>:

The Company will conduct an outreach campaign to inform customers of available resources for payment assistance. Outreach promotions include:

- CPA website updates on programs, such as the LIHEAP Recovery CRISIS Program;
- Emails to customers how have received LIHEAP funding and to other eligible low-income customers;
- Social media posts on CPA social media channels (Facebook, Twitter, LinkedIn);
- Article in the quarterly customer newsletter;
- Bill insert in customers' July bills;
- Facebook ads in targeted zip codes throughout the campaign;
- Tele-town hall event with third parties to explain the programs and services available.

- *Methods that utilities are using to make their customers aware of important proceedings that may include telephonic public input hearings and allowing consumers to be able to make their voices heard.*

<u>Company Response</u>:

The Company will be holding two telephonic public input hearings as part of its current rate case proceeding. The Company will use several methods to advise customers of the two telephonic public input hearings, including putting notice of the hearings on Columbia's website, using social media, specifically Facebook and Twitter, using newspaper publications, and emailing customers with email addresses on file with the Company.

- *Description of utility outreach methods that could be used to inform eligible Pennsylvanians about changes related to COVID-19 in the Lifeline Program for Telephone and Broadband Internet Service.*

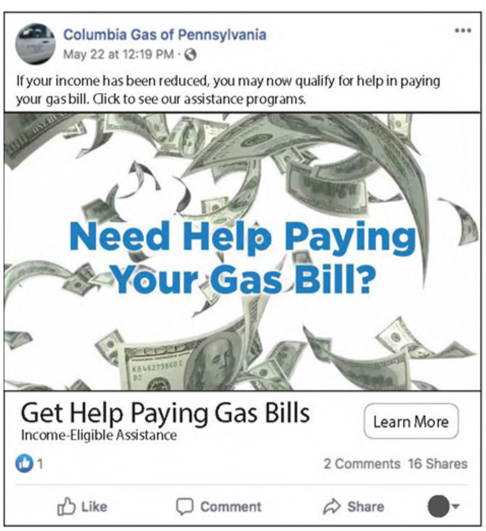
<u>Company Response</u>:

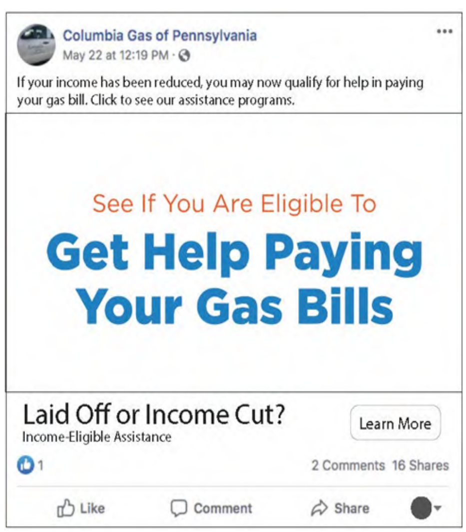
The Company was provided graphics by the PUC Communications Department to promote Lifeline and Broadband Internet Service. The Company used these graphics to promote the programs through Facebook and Twitter social media channels. Please see Attachments B for snapshots of the promotions.

Columbia Gas of Pennsylvania

COVID-19 & Customer Assistance
Social Media Content Log

Facebook






Columbia Gas of Pennsylvania
May 22 at 12:19 PM
Share the news about our many gas bill assistance programs. Someone you care about may qualify for help.
Columbia Gas
WHO NEEDS GAS BILL HELP?
Who can you help?
Income-Eligible Assistance
Learn More
1
2 Comments 16 Shares
Like
Comment
Share


Columbia Gas of Pennsylvania
STAY CONNECTED
PUC
TO APPLY
1
$7.25
Program Discounts
Pennsylvania Public Utility Commission
Like Page


Columbia Gas of Pennsylvania
We've voluntarily suspended shutoffs for nonpayment and we're offering our most flexible payment plans. We are also suspending late payment charges until May 1. Call us at 1-888-460-4332 to discuss options if you're experiencing an impact or hardship as a result of COVID-19.
Worried?
1,698
80


Columbia Gas of Pennsylvania
Additional LIHEAP funds are available for customers who are in need. Eligibility guidelines are the same as those used during the 2019-20 LIHEAP season. To learn more and apply, please visit
LIHEAP RECOVERY CRISIS PROGRAM
HOME ENERGY BILL EMERGENCY ASSISTANCE
1,537
62
Like
Comment
Share


Columbia Gas of Pennsylvania
We know that the COVID-19 pandemic may cause financial hardship for our customers. We have suspended shutoffs for nonpayment until further notice. This applies to residential, commercial and industrial customers.
Columbia Gas
A NiSource Company
Columbia Gas to Suspend Shutoffs for Non-Payment During COVID-19 Pandemic
3,376
1,626

Twitter

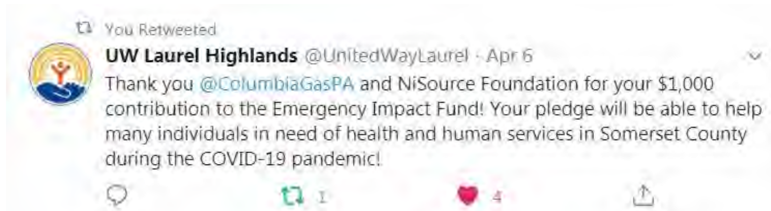

ColumbiaGasPA @ColumbiaGasPA · May 29
Additional LIHEAP funds are available for customers who are in need. Eligibility guidelines are the same as those used during the 2019-20 LIHEAP season. To learn more and apply, please visit: compass.state.pa.us

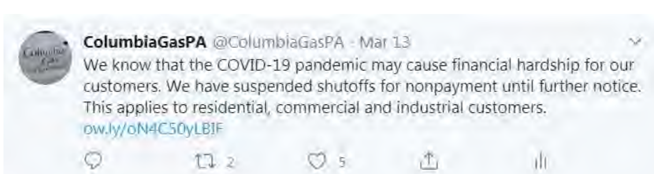

ColumbiaGasPA @ColumbiaGasPA · May 22
Additional LIHEAP funds are available for customers who are in need. Eligibility guidelines are the same as those used during the 2019-20 LIHEAP season. To learn more and apply, please visit: compass.state.pa.us


You Retweeted
PA PUC @PA_PUC · Apr 15
PUC highlights the Lifeline Program so consumers at risk of isolation can stay connected through their voice & internet service during these challenging times
puc.pa.gov/about_puc/pres...


ColumbiaGasPA @ColumbiaGasPA · Apr 6
We've voluntarily suspended shutoffs for nonpayment and we're offering our most flexible payment plans. We are also suspending late payment charges until May 1. Call us at 1-888-460-4332 to discuss options if you're experiencing an impact or hardship as a result of COVID-19.


You Retweeted
The Salvation Army WPA @SalArmyPGH · Apr 6
A huge thank you to @ColumbiaGasPA for helping us serve 1,750 meals to families and individuals impacted by #Covid19. We are so thankful for our corporate partners who step up during a time of crisis to serve our neighbors in need. #DoingTheMostGood


You Retweeted
UW Laurel Highlands @UnitedWayLaurel · Apr 6
Thank you @ColumbiaGasPA and NiSource Foundation for your $1,000 contribution to the Emergency Impact Fund! Your pledge will be able to help many individuals in need of health and human services in Somerset County during the COVID-19 pandemic!


ColumbiaGasPA @ColumbiaGasPA · Mar 13
We know that the COVID-19 pandemic may cause financial hardship for our customers. We have suspended shutoffs for nonpayment until further notice. This applies to residential, commercial and industrial customers.
ow.ly/oN4C50yLBIF

Columbia Gas of Pennsylvania
A NiSource Company

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Committed to keeping you safe

The health and safety of our customers, communities and employees is our highest priority. We continue to monitor current events and want to update you on the proactive steps we have been taking in response to the COVID-19 pandemic.

Financial assistance available

We know this could be a time of financial hardship. So, **we've voluntarily suspended shutoffs for nonpayment** in response to the COVID-19 pandemic. In addition, we're offering to customers who indicate either an impact or hardship as a result of COVID-19 our most flexible pay plans, and we will suspend late payment charges until May 1.

You also can easily manage your Columbia Gas account online at **ColumbiaGasPA.com** or over the phone at **1-888-460-4332**.

Stopping some work

To do our part to help protect our customers, employees and those most vulnerable, we will stop some types of work until further notice. By doing this, we'll be able to put all our focus on the most essential work to ensure that our system remains safe and reliable.

Most work that customers request will remain available.

Safety precautions

For any work that does continue and requires our employees to enter your home, you may notice we're taking a few additional precautions.

- We will ask for anyone in your home with a contagious illness to please keep their distance as we're working so we can help prevent spreading illnesses and continue to provide service to you and all of our other customers.
- We won't shake your hand. We promise, it's not you. It's another way to keep everyone safe.
- You may notice our gloves, shoe coverings, disinfectant wipes or other protective gear; don't be alarmed. Our team carries these items to preserve the condition of your home and the homes of other customers.

Thank you for your patience

These changes may inconvenience some customers, and we apologize in advance. We look forward to resuming normal operations when it is safe to do so.

Please check our **website** and social media for updates. We'll do our best to keep you informed.

Looking for the latest COVID-19 information? **We recommend the CDC's website**.

Columbia Gas of Pennsylvania
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Our employees are hard at work

We know that you rely on us for the energy that heats your home, cooks your food, provides hot water and more. During this time of uncertainty, our employees continue to work to ensure you have the safe, reliable natural gas service that you need throughout the COVID-19 pandemic.

We are taking appropriate precautions to maintain the health and safety of our customers, communities and employees. We are ensuring that our system is safe and, if an outbreak would occur in our service territories, have plans in place to suspend all non-emergency work if necessary.

Putting all of our focus on the most important work

To do our part to help protect our customers, employees and those most vulnerable, we will stop some types of work until further notice. By doing this, we'll be able to put all our focus on the most essential work to ensure that our system remains safe and reliable.

Most work that you would request, such as starting and stopping service, will continue to be available. But we may not be able to complete other types of requests. If you have already scheduled work that we will not be able to complete, we will contact you.

Scammers may try to target you

Scams are on the rise. We will never call you directly to ask for account or payment information. We also never demand payment through a prepaid debit card.

Learn How to Spot Impostors

Reminders about bills and payments

We know this could be a time of financial hardship. So, we've voluntarily suspended shutoffs for nonpayment in response to the COVID-19 pandemic. In addition, we're offering to customers who indicate either an impact or hardship as a result of COVID-19 our most flexible payment plans, and we will suspend late payment charges until May 1. We are here to help you, so please call to discuss all available options when you receive your monthly bill.

Learn More

Managing energy use

More time at home during the COVID-19 pandemic, might mean higher energy use this month. Don't forget that there are a variety of ways to save energy at home.

Get Home Energy Tips

Get more information

You can get updates on our website at **ColumbiaGasPA.com/COVID-19**.

Looking for the latest COVID-19 information? **We recommend the CDC's website**.

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We're continuing to suspend late payment charges until June 1

We know this could be a time of financial hardship, so we're doing what we can to help. Late payment charges will be suspended until June 1.

We've also voluntarily suspended shutoffs for nonpayment and we're offering our most flexible payment plans to customers who indicate either an impact or hardship as a result of COVID-19.

We have a variety of socially distant payment options available. You can call us, pay online or pay by mail. Remember, with more people at home, utility bills could be higher. Check out our tips to help you save energy.

Learn more at ColumbiaGasPA.com/COVID-19.

Additional resources are available

You may qualify for assistance for a number of human services. The CARES (Coronavirus Aid, Relief, and Economic Security) Act has allocated additional funding to programs like the Low-Income Home Energy Assistance Program and the Community Services Block Grant.

These programs can help individuals and families cover costs related to energy bills, employment, education, transportation, food, housing and more.

Find out if you may be eligible using our income-eligibility calculator or reach out to your local community action agency for more information.

Partnering to support families impacted by COVID-19

We're committed to helping our communities and one way we're doing so is by partnering with the American Red Cross, a longtime partner who shares our focus on safety and helping people in the most trying of times. Through the NiSource Charitable Foundation, we've pledged $110,000 to local American Red Cross chapters throughout Pennsylvania to support families impacted by COVID-19.

An additional $31,000 will be donated throughout Pennsylvania and Maryland to help fund local food banks for the purchase of food and needed supplies.

We're continuing to provide essential services

You can rest assured: We will continue to do the work necessary to provide you with safe and reliable service including answering your calls, responding to emergencies and supplying gas to our customers.

Continue to get updates about our response to the coronavirus pandemic at ColumbiaGasPA.com/COVID-19. Looking for the latest COVID-19 information? We recommend the Centers for Disease Control and Prevention website, CDC.gov.

We're taking proactive steps to protect customers and employees

If we need to come to your home or business for essential work, please know our employees are practicing social distancing and will minimize time spent inside to what is needed to accomplish the task.

Our employees could wear personal protective equipment appropriate for the situation and the job, such as gloves, face coverings, etc. They will politely avoid handshaking or any other physical contact.

Support social distancing: Call 811 before you dig

Avoid service interruption, potential fines and reduce risk for us all.

Call 811 or submit a request online three business days in advance to have underground utilities marked and help maintain social distance. If your natural gas service is interrupted, our service technicians will need to enter homes and businesses as part of the restoration process. Every digging project should start with calling 811, even now.

Submit a request online

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View in Browser

Late payment charges suspended until further notice

We know this could continue to be a time of financial hardship, so we've suspended late payment charges until further notice. We've also voluntarily suspended shutoffs for nonpayment and are offering our most flexible payment plans to customers who indicate either an impact or hardship as a result of COVID-19. We are here to help. Contact us at the first sign you may have trouble paying your bill, so we can work with you. Remember, you don't need to leave home to manage your Columbia Gas account; you can manage your bill over the phone, online or by mail.

Looking for ways to manage your energy usage? Visit **ColumbiaGasPA.com/COVID-19** for tips.

Please continue to stay safe as we weather this together.

We're continuing to perform essential work

You may wonder why you're still seeing our employees working in or around your neighborhood.

We're focused on ensuring that our system remains safe and reliable to provide the essential energy you need when it matters most.

Customers rely on us for the safe and reliable delivery of energy to their homes and businesses. Due to the nature of our work, not all of our employees have the ability to work from home. Know that we're following safety precautions recommended by the Centers for Disease Control and Prevention (CDC). As a reminder, our employees and contractors wear their company IDs visibly. Feel free to ask to see their ID. If you're unsure, you can reach out to our customer care team.

You will see our employees wearing face coverings or face

masks

If we need to enter your home or business to complete essential work, please know our employees are following these guidelines from the CDC to keep themselves and our customers safe:

- Practicing good hygiene
- Practicing social distancing (maintaining six feet from others)
- Wearing personal protective equipment appropriate for the situation and the job, such as gloves, face coverings, etc.
- Avoiding touching their face, eyes, nose or mouth, handshaking and any other physical contact

Our employees are also minimizing time spent in customers' homes and businesses by only performing work that is essential to complete our tasks safely.

Columbia Cares

Many families are struggling, so we've partnered with local organizations that provide our most vulnerable neighbors with food and other basic needs. Through the NiSource Charitable Foundation*, we recently contributed $136,500 to Pennsylvania non-profits to provide coronavirus (COVID-19) relief support, including $110,000 to American Red Cross chapters. Pennsylvanians will get through this trying time by working together. We're proud to partner with organizations making a difference in our communities.

Learn more about our community giving at **ColumbiaGasPA.com/GivingBack**.

** NiSource Charitable Foundation 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.*

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Columbia Gas of Pennsylvania
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View in Browser

Access energy assistance resources

You may qualify for assistance from a number of community action agencies. The CARES (Coronavirus Aid, Relief, and Economic Security) Act has allocated additional funding to programs that can help individuals and families cover costs related to energy bills, employment, education, transportation, food, housing and more. You may be eligible if you have been laid off or had your hours reduced due to COVID-19.

Even if you have never been eligible before, you may be eligible now.

Find out if you may be eligible using our income-eligibility calculator or reach out to your local community action agency for more information.

Learn More

Late payment charges suspended until further notice

We know this could continue to be a time of financial hardship, so we've suspended late payment charges until further notice. We've also voluntarily suspended shutoffs for nonpayment.

We are here to help. Contact us at the first sign you may have trouble paying your bill, so we can work with you. Remember, you don't need to leave home to manage your Columbia Gas account; you can manage your bill over the phone, online or by mail.

Looking for ways to manage your energy usage? Visit **ColumbiaGasPA.com/COVID-19** for tips.

Please continue to stay safe as we weather this together.

We're continuing to perform essential work

Wondering why you're still seeing our employees working in your community?

We know you rely on us to deliver safe and reliable energy to your homes and businesses each day. To help keep everyone safe, we've adjusted the work we're doing to minimize the need to enter customers' homes or disrupt their service.

Beginning May 4, we will be resuming construction work on some pipeline replacement projects that had been paused due to COVID-19. If your natural gas service will be impacted by a Columbia Gas pipeline replacement project, you will receive a letter and a doorhanger outlining our safety procedures, and one of our employees or business partners will make contact with you before performing any in-home work. Please be sure to update your contact information on **our website**, so that we have the most up-to-date information for you and can reach you easily.

At all times, please keep your distance (at least 6 feet), so our employees can keep working safely.

You will see our employees wearing face coverings

If we need to enter your home or business to complete essential work, please know our employees are following these recommendations from the Centers for Disease Control and Prevention to keep themselves and our customers safe:

- Washing their hands with soap and water or using hand sanitizer
- Practicing social distancing (maintaining six feet from others)
- Wearing personal protective equipment appropriate for the situation and the job, such as gloves, face coverings, etc.
- Avoiding touching their face, eyes, nose or mouth, handshaking and any other physical contact

Our employees are also minimizing time spent inside to what is needed to safely accomplish the task.

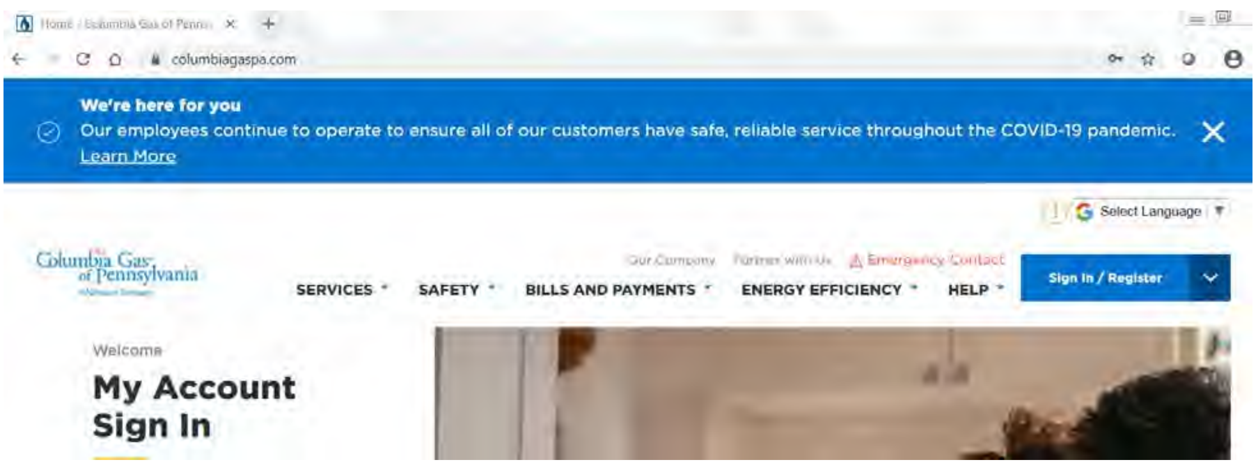
Protect yourself from scams

Scams related to the COVID-19 outbreak are on the rise. Remember we will never call you to ask for account or payment information. We also never demand payment through a prepaid debit card. If someone comes to your home claiming to be a Columbia Gas representative and you are unsure:

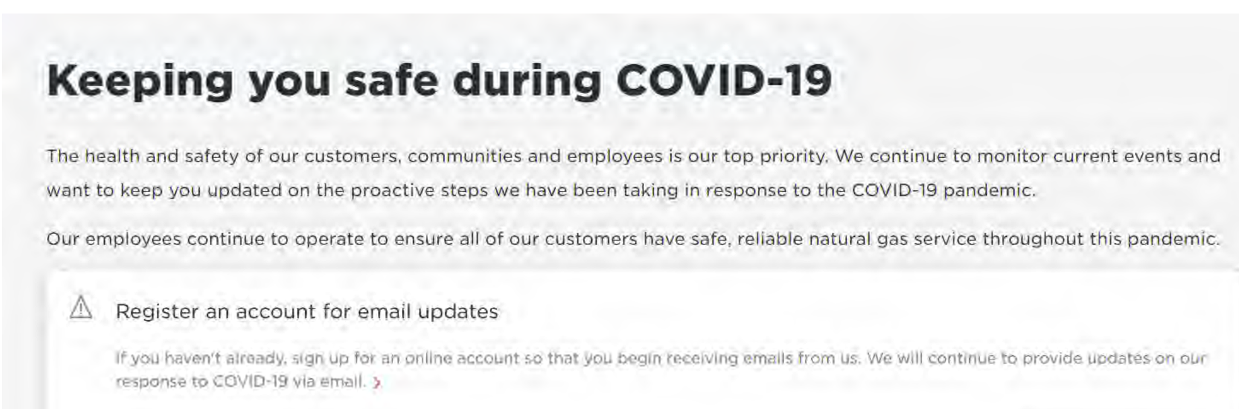
- **Ask for ID** - Our employees and contractors wear their IDs visibly.
- **Call us** - If you are not sure about a phone call, email, program, offer or person claiming to be affiliated with Columbia Gas, please call our customer care team. You can find our number on your bill or our website.

Learn more about scams and how to spot impostors at **ColumbiaGasPA.com/Scams**.

Columbia Gas of PA website Home Page and link to COVID-19 Pandemic information



First paragraph of website after clicking Learn More



Bill Payment assistance in Pandemic section of Website

Managing bills and payments

We know this could be a time of financial hardship. So, we've voluntarily suspended shutoffs for nonpayment in response to the COVID-19 pandemic. In addition, we're offering to customers who indicate either an impact or hardship as a result of COVID-19 our most flexible payment plans, and we will suspend late payment charges until further notice.

Learn More

Other helpful information

Low Income

LIHEAP recovery CRISIS program information on website

Other helpful information

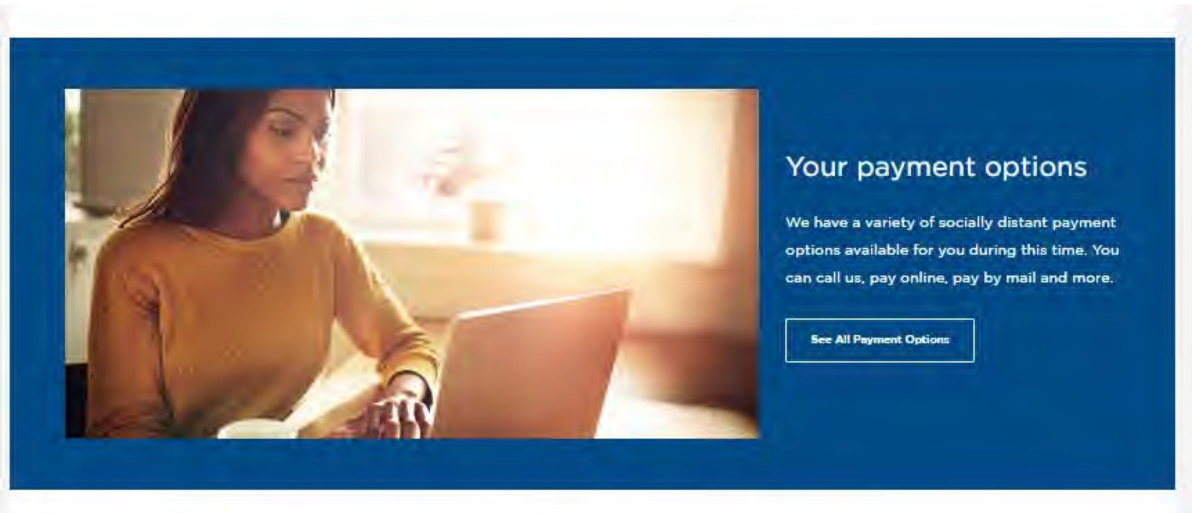
Low Income Home Energy Assistance Program Recovery CRISIS Program

This program has been established to assist customers who may need help with their gas bills as a result of the COVID-19 pandemic. Customers with incomes at or below 150 percent of the federal poverty income guidelines may be eligible for additional assistance. Administered through the Pennsylvania Department of Human Services, the program runs through August 31, 2020 or until funds have been exhausted. Download an application or call us at 1-800-272-2714 to request an application be mailed to your home.

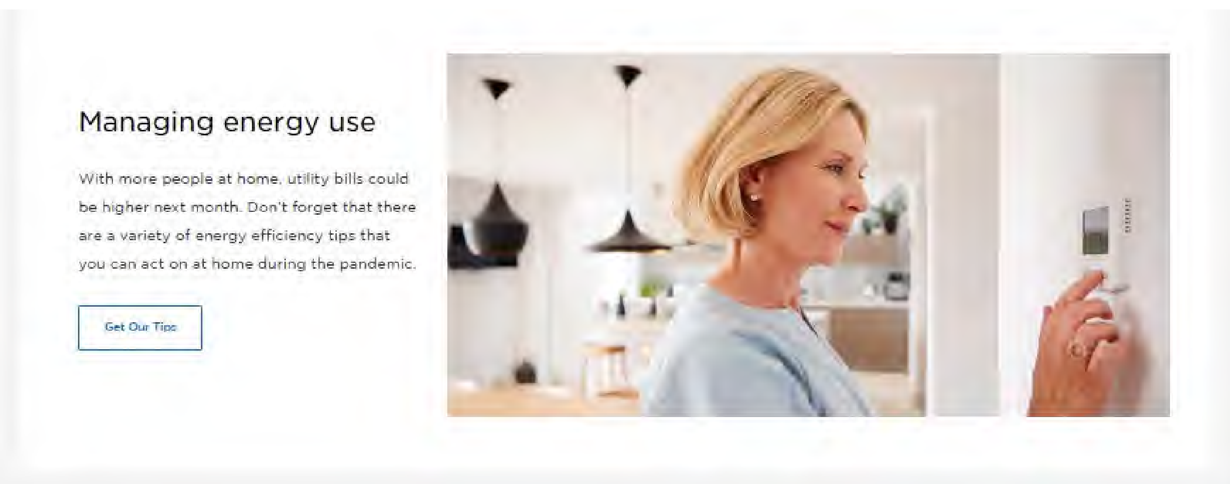
Aplicación en español.

Apply for LIHEAP

Payment Options



Energy Efficiency Tips



Scam alert message

Safety precautions

Our employees are taking all appropriate precautions to keep themselves and our customers safe. To help reduce the spread of COVID-19, until further notice, employees whose positions allow it are working remotely. For those critical employees who must report in person to complete their work, additional precautions are being taken to minimize the spread.

For any work that does continue and requires our employees to enter your home, you may notice we're taking a few additional precautions:

- ✓ We will ask for anyone in your home with a contagious illness to please keep their distance as we're working so we can help prevent spreading illnesses and continue to provide service to you and all of our other customers.
- ✓ We won't shake your hand. We promise, it's not you. It's another way to keep everyone safe.
- ✓ You may notice our gloves, shoe coverings, disinfectant wipes or other protective gear; don't be alarmed. Our team carries these items to preserve the condition of your home and the homes of other customers.

Scammers may try to target you

Scams related to the COVID-19 outbreak are on the rise. We will never call you directly to ask for account or payment information. We also never demand payment through a prepaid debit card.

Learn More

Flexible Payment Options

We're here for you
Our employees continue to operate to ensure all of our customers have safe, reliable service throughout the COVID-19 pandemic.
Learn More

Select Language

Columbia Gas of Pennsylvania

Our Company | Partner with Us | Emergency Contact

SERVICES | SAFETY | BILLS AND PAYMENTS | ENERGY EFFICIENCY | HELP | Sign In / Register

WE'RE HERE FOR YOU

COVID-19 support with flexible payment options

Act now so you can relax later. Payment plans and assistance programs are available to make bills easier to manage. Disconnections and late fees are suspended until further notice.

If you're struggling, please don't wait – contact us today so can find an option that works for you.

Learn more

Managing your Columbia Gas account during the COVID-19 pandemic

We know this could be a time of financial hardship. So, we've voluntarily suspended shutoffs for nonpayment in response to the COVID-19 pandemic. In addition, we're offering to customers who indicate either an impact or hardship as a result of COVID-19 our most flexible payment plans, and we will suspend late payment charges until further notice.

Learn More

Save money on your energy bill

While some of our in-home energy efficiency programs are on hold, don't forget that there are a variety of energy efficiency tips that you can act on at home during the pandemic.

See Home Energy Tips

Get on our Budget Plan

This program allows you to pay about the same amount each month, and we calculate that number based on usage, weather and projected costs.

Sign in to Enroll Today

Working Safely

We're here for you
Our employees continue to operate to ensure all of our customers have safe, reliable service throughout the COVID-19 pandemic.
Learn More

Select Language

Columbia Gas of Pennsylvania

Our Company | Partner with Us | Emergency Contact

SERVICES | SAFETY | BILLS AND PAYMENTS | ENERGY EFFICIENCY | HELP | Sign In / Register

Putting all of our focus on the most important work

To do our part to help protect our customers, employees and those most vulnerable, we will stop some types of work until further notice. By doing this, we'll be able to put all our focus on the most essential work to ensure that our system remains safe and reliable.

Most work that customers request, such as starting and stopping service, will continue to be available. But we may not be able to complete other types of requests. If you have already scheduled work that we will not be able to complete, we will contact you.

We're sorry for the inconvenience our work change may cause for some customers, and ask for your patience as we focus our energies on protecting customers, communities and employees. We look forward to resuming normal operations when it is safe to do so.

Working safely in your neighborhood

We know you rely on us to deliver safe and reliable energy to your home or business each day. Here are some of the things our employees and contractors do to protect you if we need to work inside your home:

- ✓ Assess their health daily
- ✓ Wear a face covering in accordance with state orders
- ✓ Maintain at least six feet of social distance during their work
- ✓ Use additional protective gear when needed
- ✓ Clean work surfaces

Protecting the safety of our customers, communities and employees is our top priority. We respectfully request when interacting with our employees that you also wear a face covering (if able) and maintain six feet of social distance.

Register an account for email updates

If you haven't already, sign up for an online account so that you begin receiving emails from us. We will continue to provide updates on our response to COVID-19 via email. >

Scammers may target you

Scams related to the COVID-19 outbreak are on the rise. We will never call you directly to ask for account or payment information. We also never demand payment through a prepaid debit card. >

These changes may inconvenience some customers, and we apologize in advance. We look forward to resuming normal operations when it is safe to do so.

Looking for the latest COVID-19 information? We recommend the CDC's website

Customer Assistance Programs

Need Help Paying Your Gas Bill?

If you're facing a temporary or longer term hardship and can't afford to pay your gas bill, Columbia Gas can help. We offer a number of options to help you get back on track.

LIHEAP Recovery CRISIS Program

The Low Income Home Energy Assistance Program (LIHEAP) Recovery CRISIS Program has been established to assist customers that may need help with their gas bills as a result of the COVID-19 pandemic. Customers with incomes at or below 150 percent of the federal poverty income guidelines may be eligible for assistance of up to $800 in grants.

Administered through the Pennsylvania Department of Human Services, the Recovery CRISIS Program runs through August 31, 2020 or until funds have been exhausted. To apply, visit the department's COMPASS website at **www.Compass.State.PA.us**

You also can download a paper application at **ColumbiaGasPA.com/Covid-19**.

Hardship Fund

Administered by the Dollar Energy Fund, this program provides up to $500 for customers at or below 200 percent of the federal poverty income guideline. A local community agency can assist you in completing an application and if eligible, funds will be applied directly to your gas bill. Access to the program is on a first come basis while funds last. To apply call **1-800-537-7431**

Customer Assistance Program (CAP)

CAP offers affordable payment plans for customers with low incomes and long-term bill payment problems. To be eligible, a household income must fall at or below 150 percent of the federal poverty income guidelines [illegible] customers who are interested in a more permanent solution may find CAP to be a valuable tool and resource. To apply for CAP call our toll free hotline **1-800-537-7431**.

Flexible Payment Plans

Customers experiencing an impact or hardship as a result of COVID-19 may be eligible to enroll in extended payment plans online. These plans help to spread the balance due over multiple months so you can pay down a past due balance and continue to stay current with upcoming payments. You'll need to register an online account to get started.

Not sure where to start? Call Columbia Gas at **1-888-460-4332** or visit **ColumbiaGasPA.com** to find out which programs or services might work best for you and your situation.

PA07261

Columbia Gas of Pennsylvania
A NiSource Company

View in Browser

We're resuming more work

We're resuming some projects that were on hold. We will do our best to inform you of upcoming work in your area.

In light of COVID-19, we've prioritized work that is considered essential for safety and system integrity, including continuing work such as pipeline replacement projects, installing additional safety measures and completing federally mandated natural gas safety inspections.

To help keep our employees, contractor partners and customers safe, we've taken proactive steps to adjust the work we're performing to minimize the need to enter customers' homes and businesses during this time.

If we need to enter your home or business to complete essential work, please know our employees are following state orders and recommendations from the Centers for Disease Control and Prevention to keep themselves and our customers safe including:

- Washing their hands with soap and water or using hand sanitizer
- Practicing social distancing (maintaining six feet from others)
- Wearing personal protective equipment appropriate for the situation and the job, such as gloves, face coverings, etc.
- Avoiding touching their face, eyes, nose or mouth, handshaking and any other physical contact
- Minimizing time spent inside customer's homes or business to safely accomplish the task.

We're here to help

We have a variety of options available to support customers during the COVID-19 pandemic including our touchless payment options like paperless billing and online payment. We're offering our most flexible payment plans to customers who indicate either an impact or hardship as a result of COVID-19. We've also voluntarily suspended shutoffs for nonpayment and suspended late payment charges until further notice.

Customers experiencing an impact or hardship as a result of COVID-19 may be eligible to enroll in one of our payment plans online. These plans help to spread the balance due over multiple months, so you can pay down a past due balance and continue to stay on track with upcoming payments. You'll need to register an online account to get started.

The Low Income Home Energy Assistance Program (LIHEAP) **Recovery CRISIS Program** has been established to assist customers who may need additional help with their gas bills as a result of the COVID-19 pandemic. Customers with incomes at or below 150 percent of the federal poverty income guidelines may be eligible for additional assistance. This program is administered through the Pennsylvania Department of Human Services and will run through August 31, 2020 or until funds have been exhausted.

Sign In

Support social distancing: Call 811 before you dig

Don't make emergency responders respond to another emergency - call 811 before you dig or visit the **Pennsylvania 811 website** to submit an online locate request. If you damage a natural gas line, we may have to come into your home to make repairs. Let's make sure that doesn't happen.

If you're starting an outdoor project that requires digging, even now, it's important to call 811 or submit an online ticket three business days in advance. Your local utility companies will send someone to mark their lines - and then you can dig safely. 811 is fast, it's free and it's the law.

Planning your next home improvement project?

Spending more time at home may have you designing your next home improvement project. If you plan to replace or add new natural gas appliances:

- Never attempt it yourself. Make sure a qualified professional performs all work on the natural gas lines and equipment inside your home.
- If you're removing an appliance, like a stove, range or dryer, make sure the natural gas is turned off to the appliance and that the natural gas line is properly capped. A qualified professional would also be able to cap the natural gas lines for you.
- If you have flexible appliance connectors, do not reuse them.

Visit **ColumbiaGasPA.com/Installation** for more information about safe appliance installation.

You might save a life

Construction season is in full swing. It's easy to get sidetracked by distractions in the road or in the car. That's why it's so important to be mindful while driving, especially around construction zones.

- Slow down - Speeding is one of the major causes of work zone crashes.
- Keep your distance - Keep a safe distance between you and the car ahead of you, and don't tailgate.
- Obey posted signs - Obey the posted signs until you see the one that says you've left the work zone.
- Obey flaggers - You can be cited for disobeying his or her directions.

Add this to your spring cleaning list

Now is the time to clear any debris, overgrown shrubs or landscaping near the gas meter on your property. Keeping your meter visible at all times makes it accessible for maintenance or in the event of an emergency.

Flooding and your natural gas service

Flooding can damage your natural gas lines and appliances, causing a safety hazard. In the event of a flood:

- If you smell natural gas after a flood, stop what you're doing, leave the area immediately and call 911 and us at **1-888-460-4332**
- Turn off electrical power to each appliance and leave it off.
- If the natural gas is shut off at the meter, call us to turn it back on for you.

Visit **ColumbiaGasPA.com/Flooding** to learn more about what to do in the event of a flood.

Shape the future

Make sure to complete your 2020 census. You can help shape funding and planning for new clinics, school lunch programs, emergency services and more. Visit **2020Census.Gov** for more information.

Please do not respond to this email. This email was sent on behalf of Columbia Gas of Pennsylvania. You are receiving it as you have provided this email address to the company. If you would no longer like to receive these messages, you can change your preferences.

Email Subscriptions

121 Champion Way, Suite 100, Canonsburg, PA 15317
Terms of Use

Account Summary

Previous Amount Due on 05/04/2020	$[redacted]
Payments Received by 04/10/2020 Thank You	- $[redacted]
Balance on 05/08/2020	$[redacted]
Charges for Gas Service This Period	+ $[redacted]
Current Charges Due by 06/03/2020	**$[redacted]**

- For more information regarding these charges, see the Detail Charges section.

We know that the COVID-19 pandemic may cause financial hardship for our customers and the company has suspended shutoffs for nonpayment until further notice. This applies to residential, commercial and industrial customers. In addition, flexible payment plans are available to customers who indicate either an impact or hardship as a result of COVID-19. Any customer who is having trouble paying his/her bill should call 1-888-460-4332 to discuss payment arrangements and/or financial assistance programs.

Budget Payment Plan
Remember winter heating bills? Get a jump on next winter and spread the cost of heating more evenly over the year. Just pay $77.00 for your natural gas service, which includes your past due balance, plus any charges for a security deposit, Optional Services, or Dollar Energy Fund contribution instead of the amount due this month, and you'll be enrolled in the Budget Payment Plan automatically.

Yard Signage

Door Hangers


We're here
to help.


Estamos aquí
para ayudar

Columbia Gas of Pennsylvania
A NiSource Company

NATURAL GAS LINE
REPLACEMENT

We're replacing the natural gas system in your neighborhood

Dear Columbia Gas customer,

Columbia Gas of Pennsylvania, as a utility providing essential services, will be starting a natural gas pipeline replacement project in your neighborhood this month, weather permitting.

This project may include replacing your service line and moving any indoor gas meters outside at no additional cost to you. However, this stage of the project will not occur until after the upgraded pipeline has been installed in your neighborhood.

Please use extreme caution when traveling through our work zone. Please slow down and obey flaggers and all posted signs including detours and parking restrictions. We apologize for any inconvenience and will make every effort to limit traffic restrictions.

Help us keep you and our crews safe

Your safety and the safety of our workers is our first priority.

We have taken proactive steps to implement additional safety precautions as we perform work that is critical to maintaining safe and reliable natural gas service.

As we are working in your neighborhoods we will be maintaining social distancing, and ask that you help keep our teams safe and also maintain six feet of distance from our crews.

Our employees are following Centers of Disease Control and Prevention (CDC) guidelines including:

- Washing their hands with soap and water or using hand sanitizer
- Practicing social distancing where practicable (maintaining six feet from others)
- Wearing personal protective equipment (PPE) appropriate for the situation and the job, such as gloves, face coverings, etc.
- Avoiding touching their face, eyes, nose or mouth, handshaking and any other physical contact
- Using disinfectant wipes on surfaces where they are working
- Minimizing time spent inside to what is needed to accomplish the task

Our teams are happy to address any questions or concerns you have about our work in your neighborhood. Normally we would greet our customers with a handshake, but hope a smile will do in these times instead.

Restoring your natural gas service

Once we have installed the upgraded pipeline, we will then transfer your service from the old gas pipeline to the new one. During that transfer your gas service will be temporarily interrupted for several hours to ensure the safety of our crews and customers. A Columbia Gas employee or contractor will notify you in person, or with a door hanger, at least three days before we interrupt your service.

Once the gas service has been transferred, we will need access to your home or business to perform a safety check and relight your natural gas appliances. Our teams will be using PPE to ensure your safety and the safety of our employees and contractors. Restoration of service will be done at no charge to you.

Ask for photo identification

All workers carry photo ID which clearly identifies them as a Columbia Gas employee or contractor. We encourage you to ask for identification before allowing anyone into your home or business. You may also call us at **1-888-460-4332** to reach a customer service representative who will be able to verify the worker's identity. If we are unable to speak to you in person, we will leave a door hanger with information on how to schedule a service restoration appointment.

Property restoration

Our crews will document the condition of your property by taking pictures and video before construction begins. We are committed to fully restoring your property to its pre-project condition as soon as weather and seasonal conditions permit.

Please contact us if you have questions or concerns about this important project.

Also, please be sure to update your contact information online at www.ColumbiaGasPA.com, or by calling our Customer Care Center at **1-888-460-4332**, so that we have the most up-to-date information for you and can reach you easily with updates.

Sincerely,

Name
Title
Telephone number
Email

What you can expect

1. MARK the right of way and existing utilities with flags, stakes, and temporary paint. When we make personal contact with you, please alert us to any sprinkler systems or invisible dog fences.

2. REPLACE the main line. This pipe usually runs underneath your street.

3. REPLACE the service line. This line runs from the main line to the meter that serves your home or business.

4. RELOCATE any indoor gas meters to the outside of your home or business.

5. RESTORE your property to the same condition it was prior to our project. It may take several days or weeks between some of these steps.

Join us online for project updates and other Columbia Gas news

Facebook: www.facebook.com/ColumbiaGasPennsylvania
Twitter: www.twitter.com/ColumbiaGasPA

811 Know what's below. Call before you dig.

Planning a home improvement job? Planting a tree? Installing a fence or deck? **WAIT!** Here's what you need to know first. By law, everyone must contact Pennsylvania One Call by dialing 811 at least 3 business days, but no more than 10 working days, before any digging project. **It's free, and it's the law.**

September Bill Insert

ACT NOW
SO YOU CAN RELAX LATER

If you're having trouble paying your bill because of COVID-19, we understand. And, we're here to help.

We are now offering flexible payment plans to help you get back on track.

Visit **ColumbiaGasPA.com/Covid** to learn more about your options.

Columbia Gas

OPTIONS
TO HELP

FLEXIBLE PAYMENT PLANS

We now have an easy online way to help choose a payment plan and spread your balance across multiple months.

ASSISTANCE PROGRAMS

Find out if you may be eligible using our income-eligibility calculator or reach out to your local community action agency.

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PREDICTABLE BILLS
FOR UNPREDICTABLE TIMES

This chart is for illustration purposes only and represents a simulated Budget Plan bill payment plan. Your payments will vary based on actual usage.

ENROLL IN OUR BUDGET PLAN
PAY THE SAME AMOUNT EACH MONTH

- ✓ Be prepared before the cold weather hits
- ✓ Balance seasonal highs and lows
- ✓ Know exactly how much you need to pay each month

THREE WAYS TO ENROLL

1. **Automatically**
   Just pay the budget amount that appears on your bill
2. **Online**
   Enroll at ColumbiaGasPA.com/Budget
3. **Phone**
   Call 1-888-460-4332

PA09201


Columbia Gas of Pennsylvania
Published by Sarah Perry NiSource · April 30
STAY CONNECTED
PUC
with Lifeline Telephone and Broadband Assistance Program
1
Number of benefits allowed per household
TO APPLY:
Contact Your Service Provider
Or Call 1-800-234-9743
$7.25
Program Discounts
Effective Date
Voice (Fixed & Mobile)
Broadband (Fixed & Mobile)
Pennsylvania Public Utility Commission
April 15
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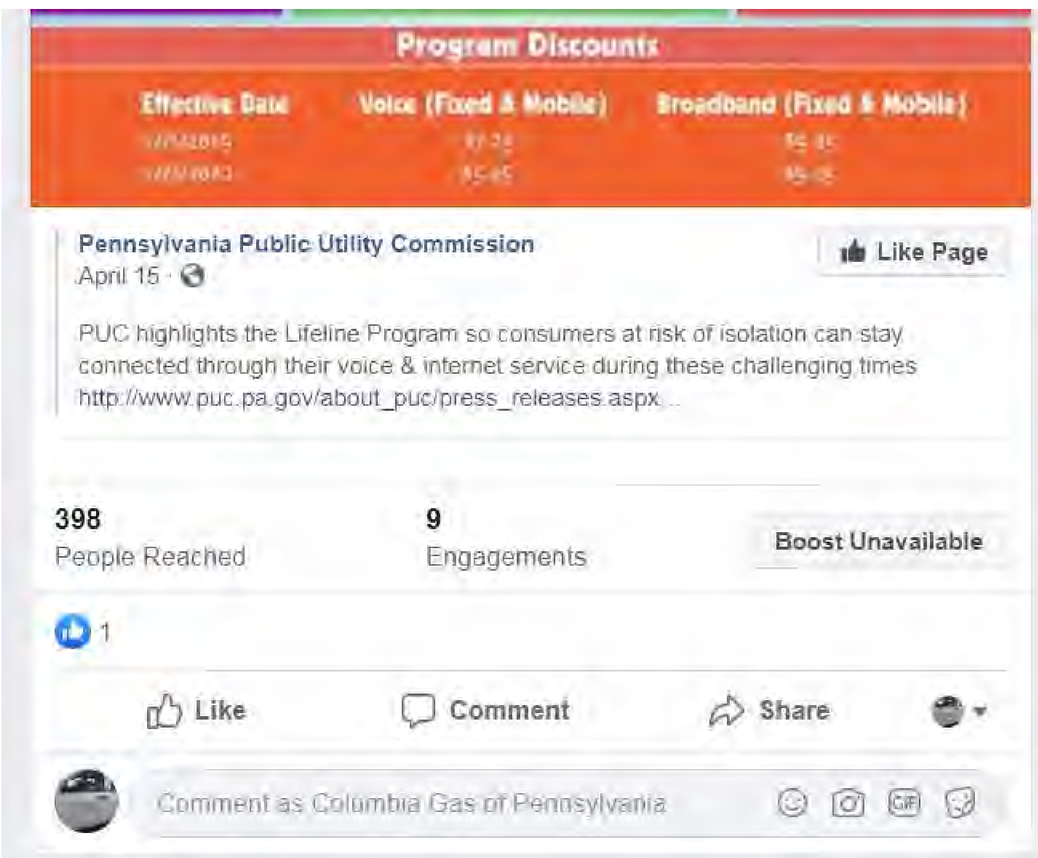
Program Discounts
Effective Date
Voice (Fixed & Mobile)
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11 12

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COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Bureau of Investigation & Enforcement – Set GS

Question No. I&E-GS-002:

Reference non-PennDOT standard restoration requirements by municipalities on page 12 of Columbia Gas Statement No. 14. For projects involving non-PennDOT standard restoration requirements by municipalities from 2015 through 2019, please provide:

A. A schedule showing the address of the project, the name of the municipality, the total budgeted cost of the project, the actual cost of the project, the total restoration cost of the project and PennDOT standard restoration cost;
B. Any action(s) Columbia Gas took regarding the non-PennDOT standard restoration requirement by the municipality including litigations; and
C. Where in the filing are these amounts reflected?

Response:

A. Please see I&E-GS-002 Attachment A that shows a report that is utilized to show paving and restoration costs against the total cost of the project for replacement work (Age & Condition – Job Type 557, Betterment – Job Type 559, and Public Improvement – Job Type 561). This is based on the year the project was completed. The Company does not have this by municipality, but the information can be filtered by County and City Codes which are depicted in I&E-GS-002 Attachment B. Please note, Attachment A contains all municipal and PennDOT related projects as the Company is unable to separate the projects due to reporting limitations.

   The Company typically follows the municipality's ordinance for restoration, unless the Company deems it unreasonable. At that point, the Company would try and negotiate with the municipality, and may reference the use of a PennDOT standard to see if an agreement could be reached. Attachment A does not break out restoration costs specific to a particular PennDOT standard.

B. To date, Columbia has not litigated any municipal restoration issues, as the need has not arisen. As stated in Columbia statement 14, pages 7-14, the Company has undertaken significant outreach efforts with municipalities to educate them about our pipeline replacement efforts. Over the past five years, Columbia has been successful in negotiating restoration requirements with municipalities. See I&E-GS-002 Attachment C for a list of municipalities where successful negotiation regarding restoration requirements has been achieved.

C. For the FPFTY, all restoration costs are part of the Company's capital budget.

Successful Municipal Restoration Negotiation

- **Dellrose Street, City of Pittsburgh** – The City of Pittsburgh Public Works road restoration provisions required a complete rebuild of at least half the road from the base up. For Dellrose Street, which is a brick surface street, Columbia estimated that compliance with this requirement would have cost in excess of $1 million. Columbia negotiated a restoration plan to install permeable pavers, which reduced restoration costs by an estimated 30 percent.
- **City of Pittsburgh** – This was a collaborative effort among Columbia and other utilities to challenge the City's proposed "Major Street Opening Permit" revision that would have increased costs and possibly delayed pipeline replacement projects in Pittsburgh. Columbia Gas, working with the other utilities, was able to amend the bill to exclude utility infrastructure work. Also, challenged and successfully delayed for a year, the City's attempt to implement an increased requirement of four inch mill and overlay for pipeline replacement projects on major streets, resulting in savings of $100,000.
- **Cross Creek Township, Washington County** – Columbia successfully sought revision of a provision in a road maintenance agreement between Columbia and the Township which required 200 feet of mill and overlay paving curb to curb on each side of a road opening. Columbia successfully negotiated a restoration plan with the Township, saving more than $42,000 in restoration costs.
- **Ambridge Township –** Subsequent to a public meeting attended by Columbia to educate the residents about an upcoming pipeline replacement

and prior to the commencement of our pipeline replacement project, the Township enacted new restoration ordinances. Columbia was able to successfully negotiate with the township restoration standards, which did not increase costs significantly for the planned project.

- **City of Uniontown, Fayette County:** The mayor attempted to enact additional paving restoration requirements for a pipeline replacement project in the city that was outside the requirements of the City's ordinance. Columbia resolved the issue by creating a paving "co-op" agreement and providing the City $15,000, our estimated cost for restoration on the street.
- **Springfield Township, York County:** Columbia opposed proposed road restoration requirements on a new business project to provide natural gas service to more than 80 new customers. Township officials were concerned Columbia was cutting into newer roads and requested extensive paving restoration. Columbia negotiated a reasonable restoration plan, paving only in areas where the Company worked.
- **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 early 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. Columbia and Beaver officials met again late last year to review the 2019 projects and restoration efforts and reached 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.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Small Business Advocate – Set 1

Question No. OSBA 1-003:

Reference Columbia Statement No. 14, pages 3-6. Mr. Kitchell offers several explanations for the large increase in mains replacement costs per foot. To the extent available, please quantify the impacts of the various factors from 2008 to 2019:

a. Please provide the percentage of mains replacement footage under hard surfaces for each year. Is there any reason to believe that this figure is increasing during this period?

b. Please provide the percentage of mains replacement footage in urban areas for each year. Is there any reason to believe that this figure is increasing during this period?

c. Please provide Columbia's estimate of the incremental cost associated with stricter municipal requirements in each year.

d. Please provide Columbia's estimate of the impact of contractor pricing exclusive of other factors on per-foot replacement costs.

Response:

A. Please see chart below which represents paving and restoration costs against the total cost of the project for replacement work (Age & Condition - Job Type 557, Betterment – Job Type 559, and Public Improvement – Job Type 561). This is based on the year in which the project was completed and is not available prior to 2011. Furthermore, please see the response to C to show efforts being made by Columbia to manage this aspect of work.

Row Labels	Sum of Tot Act Cost	Sum of Act Pave & Rest	% Pave & Rest
2011	$78,698,006	$27,429,998	35%
2012	$82,667,432	$26,857,962	32%
2013	$98,773,477	$42,366,613	43%
2014	$105,092,265	$44,059,419	42%
2015	$128,732,259	$44,321,018	34%
2016	$126,085,810	$42,278,920	34%
2017	$176,764,264	$58,341,806	33%
2018	$111,695,773	$40,606,733	36%
2019	$182,325,062	$58,323,421	32%
Grand Total	**$1,090,834,348**	**$384,585,889**	**35%**

B. Columbia's Work Management System does not differentiate between urban versus suburban or rural. The paving and restoration portion of the job order estimate is calculated based on the governmental / municipal requirements. Please see the response to C to show efforts being made by Columbia to manage this aspect of work.

C. When the company plans the capital budget for pipeline replacement costs, the budget includes restoration costs in total. The Company does not uniquely identify costs resulting from stricter municipal requirements in the budget. Much of Columbia's budget plans are built upon historic trends and average unit costs. Further, given the company operates in 26 counties and 450 communities, it is not practical to develop a set of assumptions that would enable the Company to measure on a project basis incremental costs resulting from stricter municipal requirements.

To address the financial impact of municipal requirements, the company has chosen to be proactive with municipalities in this area, as addressed in Columbia Statement No. 14. The company has been impacted by a wide range of different municipal requirements, and has been very successful in negotiating favorable outcomes when faced with what is perceived to be an unreasonable requirement. See OSBA 1-003 Attachment A for successful outcomes relating to municipal ordinances, and Attachment C in the Company's response to I&E GS-002 for successful municipal restoration negotiation.

D. Data going back to 2008 does not include the detail necessary to separate contractor unit costs increases from all other increases to provide a per foot cost impact. Since 2008 the scope of contracts has changed to modify or add additional units which further complicates the data collection and comparison. Additionally contractor pricing increases have been merged with other internal measurements such as scope, units, materials, and overheads among other items. In general a minimum escalator has been negotiated as part of 3-5 year contracts awarded during the 2008-2019 time period ranging from 2.2% to 3.3% annually, and was based off of inflationary indexes to keep up with an average cost of living. Further as Columbia identified risks, undertook discussions with gas safety regulators at the Commission or reached settlement agreements with parties in base rate proceedings, additional processes and requirements were negotiated with contractors prior to implementation. Some examples of requirements or processes added that have impacted unit cost or cost per foot are; Sewer camera (cross bore prevention), Enhanced OQ (incremental training and qualification requirements), and Pennsylvania specific environmental controls, to name some of the most significant cost impacts. Lastly in more recent years the competition for labor resource as a result of a booming construction industry and historically low unemployment rates has had an impact, although at this time it is difficult to quantify a percentage or cost per foot.

Successful Outcomes – Municipal Ordinance Negotiation

- **Redevelopment Authority of Washington County:** Negotiated with the Redevelopment Authority of Washington County to obtain an easement on property they own for a needed pipeline replacement project. Cost was reduced from $50,000 to a fair market value of $20,000.
- **City of Washington Traffic Control Costs:** Working with the City of Washington, restoration costs were reduced by $70,000 in a one year period. The City has agreed that an ordinance requiring two police offers to provide pedestrian and vehicle safety on all pipeline replacement projects should only be enforced on major roads, not side streets with sparse vehicle and pedestrian traffic.
- **Connellsville -** Successful challenge of fair market value of easements on two pieces of city owned property necessary for pipeline replacement, resulting in savings of $22,500.
- **Leet Township -** Negotiating with township regarding a demand from the township engineer to provide highly detailed drawings for every road opening made by Columbia on a proposed pipeline replacement in order to obtain a permit. Estimated cost of drawing was $25,000.
- **Elizabeth Township, Allegheny County Pipeline Ordinance:** Columbia joined with production and mid-stream companies to oppose a proposed pipeline ordinance which could have increased permitting fees to at

least $50,000. The ordinance is not expected to be considered because of lack of support.

- **East Washington Borough, Washington County:** Columbia worked with the borough to reach a reasonable agreement on permit fees and restoration requirements for a 2018 pipeline replacement project. Columbia rejected a proposed $17,000 permit fee for the project. CPA resolved the issue for a $250 permit fee, balanced road restoration requirements and a $7,500 escrow account to pay for any engineering or inspection services that were necessary in review of and during the project.

- **Harmony Township, Beaver County:** The township proposed a permit fee in the amount of $82,500 related to a pipeline replacement project. Columbia resolved the issue with a $5,000 permit fee and additional paving "co-op" in the amount of $17,000.

Restoration Costs of 10 Largest 2013 CPA Projects Review

March 31, 2015

To: Mark Kempic, President CPA

From: Mike Easterday, Audit Senior
Jaclyn Callahan, Audit Manager
Ryan Binkley, Audit Director

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Table of Contents

EXECUTIVE OVERVIEW

Selected 2013 CPA Restoration Projects Audit

Executive Overview

Scope and Conclusion:

As part of a recent rate case settlement approved by the Pennsylvania Public Utility Commission (PUC), Columbia Gas of Pennsylvania (Columbia or the Company) requested NiSource Internal Audit to conduct procedures to "*undertake audits of the restoration costs for its 10 largest projects in the prior year (2013), identifying costs incurred in excess of the Pennsylvania Department of Transportation (PennDOT) restoration standards for paving, sidewalk repair and permitting fees.*" Procedures included examination of documentation and discussions with Company personnel.

Internal Audit was unable to quantify costs incurred in excess of PennDOT standards. The level of detail related to restoration costs currently recorded and maintained within the Company's Work Management System (WMS) is insufficient to formally conclude on the stated scope. Evidence of restoration completed for projects selected was constrained by the following:

> *Associating Charges to a Geographic Location* - WMS does not have the functionality to track costs associated with work performed in a specific location or section of a project. As projects can span multiple streets and jurisdictions, this lack of detail creates barriers when matching charges for work performed to the required specifications for that location.
>
> *Limitations to the abilities of Company personnel to recollect details of restoration completed on projects* - Internal Audit conducted interviews of field personnel who were either involved with the selected projects at the time (up to two years ago as of the date of this report) or were a next best resource as the individuals actually involved are no longer employed with the Company. While informative, this level of corroboration limits the reliance afforded to such evidence.

Selected 2013 CPA Restoration Projects Audit

Executive Overview (Cont.)

Scope and Conclusion (continued):

Despite the constraints identified, Internal Audit completed a review of cost detail and conducted interviews with field / project management personnel. Internal Audit noted a majority of interview respondents, as well as other circumstantial documentation, corroborated that the Company restored affected roads, sidewalks, and curbs of the selected projects to the level required by local jurisdictional standards. There were instances noted when collaboration with the state, the locality, or other utilities made it possible to share restoration costs or make temporary repairs as a more comprehensive project would remedy the affected areas at a later date. Additionally, Internal Audit noted Company management has recently assigned personnel to managing restoration activities, with the intention of also creating standard documentation requirements.

Selected 2013 CPA Restoration Projects Audit

Executive Overview (Cont.)

General Observations Regarding the Management of Project Restoration

The following items were consistently noted by field personnel who were interviewed as factors contributing to increases in required restoration activities:

– ***Lack of Uniform Restoration Requirements –*** Projects executed in the Commonwealth of Pennsylvania can be subject to one or more sets of specifications contingent upon jurisdictional boundaries and the scope of the project.

– ***Increased Scrutiny and Requirements by Municipalities –*** Localities are enforcing expanding local ordinances with increasing attention.

– ***Urban Areas –*** For most of the projects reviewed, main lines were installed in urban or residential areas where infrastructure such as roads and public works were built in periods before modern building practices and standards. In addition, current restoration specifications may exceed the pre-existing road or walkway condition.

– ***Related Service Line Installs –*** For most of the projects reviewed, the installation of main lines in urban or residential areas also required the installation of new service lines to meet Company safety standards. Installation of service lines increases restoration required.

– ***Americans with Disabilities Act (ADA) Specifications –*** Federal standards for ADA compliant road and walkways continue to evolve and often require additional restoration of areas not directly affected by the install.

– ***Projects in recent years appear to be broader in scope –*** Past projects were historically smaller in scope (i.e. replacing a few hundred feet of pipe at a time) and required minimal restoration. Expansion of the capital program to replace aging infrastructure has included projects greater in size (i.e. replacing thousands of feet of main at a time as well as re-running all affected service lines.) When executing projects of this magnitude, entire streets are impacted resulting in an increase in restoration activities as compared with previous projects.

Despite the above factors, field personnel also cited many instances for the projects selected and others where the Company has collaborated with other utilities, the locality, or the state to complete restoration in a cost-effective manner for all parties involved.

PROCEDURES AND GENERAL OBSERVATIONS

Procedures and General Observations

Procedures Performed:

Prompted by the PUC's approval of a recent rate case settlement, Internal Audit conducted an audit of the ten largest 2013 projects for the Company. The Company's settlement obligation is as follows:

> *"Columbia will meet with the Commission's Gas Safety Division and other parties to identify increasing state, county and municipal requirements that exceed the Pennsylvania Department of Transportation restoration standards and add to the cost of pipeline replacements in an effort to develop coordinated potential responses to such requirements. In furtherance of such meetings, <u>Columbia will undertake audits of the restoration costs for its 10 largest projects in the prior year, identifying costs incurred in excess of the Pennsylvania Department of Transportation restoration standards for paving, sidewalk repair and permitting fees.</u>"*

Internal Audit undertook the following procedures to conduct an audit in accordance with the scope as outlined above:

Step 1: Determine the "10 largest projects in the prior year."

Step 2: Review PennDOT Restoration Specifications.

Step 3: Identify Restoration Costs Incurred for Selected Projects.

Step 4: Identify costs incurred in excess of the Pennsylvania Department of Transportation restoration standards.

Procedures and General Observations

Procedures Performed: (continued)

Step 1: Determine the "10 largest projects in the prior year [2013]"

To identify the "10 largest projects in the prior year," Internal Audit obtained reports generated by the Capital Management Department from the Budgetwiser system (a capital budgeting system which utilizes cost information agreeing to the General Ledger). The following criteria were utilized to generate the report including cost information as of August 5, 2014 (the date the report was generated):

1. Projects located in the Commonwealth of Pennsylvania;
2. Projects placed in-service during the calendar year 2013; and
3. Projects identified as job type "557," defined as "replacement and retirement of distribution lines which are found to be leaking and beyond the state of economical repair."

For those projects meeting the above criteria, Internal Audit identified the "10 largest projects" as ranked by the Total Actual Expenditure field in the Budgetwiser system. The proportion of restoration costs for each project varied depending on the nature of the project, however larger projects are more likely to involve higher levels of restoration.

Procedures and General Observations

Procedures Performed: (continued)

Step 2: Review PennDOT Restoration Specifications

To complete the required investigation, Internal Audit undertook procedures to understand PennDOT restoration specifications in effect during 2013. Internal Audit made inquiries of Columbia Regulatory, Construction Services, and Engineering department personnel, which included discussions of provisions of Publication 408/2011 “SPECIFICATIONS” that would be applicable to the type of restoration Columbia encounters when completing mainline replacement projects.

Internal Audit reviewed Publication 408/2011 directly; however, Internal Audit noted that, within its 1,300 pages, there appeared to be numerous caveats and permutations that would apply given the number of specific circumstances or scenarios for every project. Furthermore, there have been several revised editions of the specifications, three revised editions applicable during 2013, and only the most recent is available on PennDOT’s website.

Due to the complex and technical nature of the PennDOT specifications, Internal Audit determined that conclusions on the extent of restoration performed in comparison to the restoration which would have been completed following PennDOT specifications strictly, require significant reliance upon the judgment of Columbia personnel with knowledge of the projects, as well as knowledge of other applicable restoration specifications (i.e. federal, municipal).

Procedures and General Observations

Procedures Performed: (continued)

Step 3: Identify Restoration Costs Incurred for Selected Projects

Restoration activity is recorded by field personnel on manual Daily Progress Reports (DPR's) by documenting the number of units installed (i.e. square feet of 6" asphalt) by item number. The reports are then keyed into the WMS system under the applicable contract and work order. Using contractually specified rates for each item number, the system transfers total cost data by cost element to the asset accounting system (PowerPlant) as well as the general ledger (Millennium / PeopleSoft).

The WMS system limits each DPR to only one assigned cost element. Therefore, all items contained on each DPR are assigned the same cost element regardless of the nature of the activity for each item. For contractors who perform paving and concrete work exclusively, a single cost element is adequate; however for contractors who perform pipe installation, as well as restoration activities, paving related items may fall under a cost element for the primary installation.

Additionally, as the installation of new service lines commonly occur when installing new main lines, restoration costs are allocated to the main and service line replacement job orders based on a determined percentage allocation.

Per discussion with Asset Accounting, Internal Audit noted that the following cost elements relate to the restoration categories outlined by the Commission.

- 3092 – Paving Restoration (which includes Sidewalk Repair items)
- 3600 – Permitting

Procedures and General Observations

Procedures Performed: (continued)

Step 3: Identify Restoration Costs Incurred for Selected Projects (continued)

Paving Restoration
Internal Audit obtained all available paving restoration cost detail from WMS. In addition, Internal Audit held discussions with Construction Services, Engineering, and other field personnel regarding the degree of restoration on the selected projects, including whether, in their professional judgment and recollection, the work performed was in accordance with applicable specifications.

Permitting
Internal Audit was able to obtain supporting documentation for all cost element charges for permit fees in PowerPlant for each selected project. Internal Audit noted in addition to charges for permits (namely, street opening permits), the cost element also included state and municipal charges for hours incurred by inspectors reviewing the work completed on projects. Internal Audit made inquiries regarding the permit charges with personnel knowledgeable of the selected projects and noted many of the selected projects were included as phases of major projects which in all, required many years to complete. Due to the duration of the projects, it was not uncommon for permits to be obtained and charged to one phase of a project, though it included streets or sections of streets within the scope of other phases of the overall project. Therefore, not all projects selected had charges for permits while others included charges for inspection fees.

Procedures and General Observations

Procedures Performed: (continued)

Step 4: Identify costs incurred in excess of the Pennsylvania Department of Transportation restoration standards

Internal Audit could not determine the prospective difference in “paving, sidewalk repair, and permitting fees” if hypothetically completed strictly by PennDOT specifications as compared to the extent completed on the selected projects. Therefore, Internal Audit was not able to perform procedures to calculate “costs incurred in excess of the PennDOT restoration standards.” Limitations included:

1. *Associating Charges to a Geographic Location* - The functionality of WMS does not have the capacity to track charges to a specific location or section of a project. As projects can span multiple streets and jurisdictions, this lack of detail makes it difficult to match charges for work performed to the required specifications for that location.

2. *Limitations to the abilities of Company personnel to recollect details of restoration completed on projects* - Completion of procedures by Internal Audit substantially involved interviewing field personnel who were either involved with the selected projects at the time (up to two years ago) or were at least aware of the project and serving as a next best resource as the individuals actually involved are no longer employed with the Company. This level of corroboration limits the reliance afforded to such evidence.

Procedures and General Observations

General Observations:

The following items were consistently noted by field personnel who were interviewed during the review as possibly contributing to increases in required restoration activities:

Lack of Uniform Restoration Requirements Across the Commonwealth

Restoration specifications have been established by federal agencies, PennDOT and local jurisdictions. Local jurisdictions establishing their own specifications typically include provisions that are different from those established by PennDOT. Projects executed in the Commonwealth of Pennsylvania can be subject to one or more sets of specifications contingent upon jurisdictional boundaries and the scope of the project. Therefore, it is difficult to compare restoration efforts across projects as each may be subject to different specifications.

Increased Scrutiny and Restoration Requirements by Municipalities

Many townships and boroughs either have or have recently developed their own restoration specifications as the nature of the Commonwealth structure permits them to do so. Others default to state requirements, though field personnel also noted that there are municipalities which include a clause in their specifications that they reserve the right to require additional work at their discretion. Company personnel relayed that local municipality ordinances have become more expansive, including higher restoration specifications than previously required, and the Company is compelled by these laws to comply with documented specifications. It was also noted by those interviewed that cities and townships have shrinking municipal budgets, and seek to maximize the benefits of newly paved roads associated with infrastructure replacement projects.

Procedures and General Observations

General Observations (continued):

Urban Areas

Oftentimes, in long-established cities or towns where age and condition factors warrant pipe replacement, sidewalks and curbs are in significant disrepair or nearly nonexistent. In these situations, if a sidewalk is disturbed, or the installation of related service lines lead to circumstances requiring the mill and overlay of the road, the Company must also install curbs and/or sidewalks to meet required specifications.

Related Service Line Installs

Nearly every project selected within the scope of this audit involving the installation of mainlines through urban or residential areas also had related service line replacements, which further impacted the restoration activities required. If a main line was installed completely off of the road, company policy dictates the sighting of other utilities for safety reasons, requiring numerous road cuts to be made even when using trenchless technology. According to the restoration specifications of many jurisdictions, if these road cuts are within 100 feet of one another, the entire road must be milled and overlaid. Personnel also noted that projects completed only a few years ago were smaller in scope (i.e. replacing a few hundred feet on pipe at a time) and required minimal restoration. Expansion of the capital program to replace aging infrastructure has included projects greater in size (i.e. replacing thousands of feet of main at a time as well as re-running all affected service lines). When executing projects of this magnitude, entire streets are impacted resulting in an increase in restoration activities as compared with previous projects.

Procedures and General Observations

General Observations (continued):

Americans with Disabilities Act (ADA) Specifications

As outlined by the Code of Federal Regulations, there are certain requirements to restore road and walkways to a level compliant with current ADA specifications. The disruption of one ADA ramp often necessitates the upgrade of the adjacent ramp. In some cases, depending on the scope of restoration activities, all four corners of an intersection may require upgrade to meet current federal standards.

Cost-Effective Collaboration with Other Entities

Field personnel noted there are many situations where the Company will work with another utility to complete work simultaneously and share the costs of restoration. Additionally, engineers or project management staff typically attend state and municipal planning meetings to coordinate the locations and timing of repair or replacement projects where it will best fit with other planned road projects. Many instances were noted where the Company did not complete total restoration on projects as the state agreed to complete the majority of restoration activities as part of an planned road project.

OBSERVATIONS BY PROJECT

Observations by Project

#7343 Rt 51/Rt 88 Replacement Project

Project Description

This project was initiated as a result of a planned road project by the state. Due to the extent of the planned project, Columbia needed to move pipe facilities to alternate and adjacent roads. Installed 20” high pressure steel main involving both off road and in road rights-of-way installation.

Figures*

Main Footage Installed:	2,116’
Total Project Costs:	$4,844,883
Paving / Sidewalk Repair Charges:	$482,887
Permitting Charges:	$350
Total Restoration Charges:	$483,237
Total Restoration as a percentage of project costs:	~10%
Applicable Specifications:	PennDOT Pittsburgh

Field Personnel Commentary

- The Company relocated facilities from a main thoroughfare and installed pipe under side streets which were narrow and primarily brick. Pipe installation substantially disrupted these streets, thereby requiring significant restoration.
- For a section of the project, the Company was requested by the state to partially restore the road surface as it would be affected again with the continuation of a state road project.
- For a section of the project, the Company collaborated with the water utility to share restoration costs as their project similarly required disturbing the existing road.

* Information reported as of December 18, 2015.

Observations by Project

#7329 PM 2421 - Edgewood Ph 5 (Sharon Ave to Lombard Rd)

Project Description

There were six phases of the Edgewood Project which involved installing main line(s) along a few miles of Edgewood Rd. Edgewood Rd. runs down the western boundary for Winsor Township. Phase 5 was situated on the southern portion of the project involving a high pressure steel main installed along the side of the road and berm.

Figures*

Main Footage Installed:	5,798'
Total Project Costs:	$3,050,902
Paving / Sidewalk Repair Charges:	$461,445
Permitting Charges:	$13,767
Total Restoration Charges:	$475,212
Total Restoration as a percentage of project costs:	~16%
Applicable Specifications:	PennDOT

Field Personnel Commentary

- The scope of the project involved installing pipe primarily alongside the roadway and berm. Therefore, restoration required was less substantial than other projects involving pipe installation under roads or sidewalks.
- A state inspector was onsite frequently. Field personnel worked together with the inspector to agree on necessary restoration per specifications.
- It was noted permitting charges above include approximately $12,000 of PennDOT inspection charges.

* Information reported as of December 18, 2015.

Observations by Project

#7327 PM 2421 - Edgewood Road Phase 3

Project Description

There were six phases of the Edgewood Project which involved installing main line(s) along a few miles of Edgewood Rd. Phase 3 was situated on the northern portion of the project involving a high pressure steel main and a medium pressure plastic main installed primarily along the side of the road and berm.

Figures*

Main Footage Installed:	10,904’
Total Project Costs:	$2,924,946
Paving / Sidewalk Repair Charges:	$152,840
Permitting Charges:	$0
Total Restoration Charges:	$152,840
Total Restoration as a percentage of project costs:	~5%
Applicable Specifications:	PennDOT

Field Personnel Commentary

- The scope of the project involved installing pipe primarily alongside the roadway and berm. Therefore, restoration required was less substantial than other projects involving pipe installation under roads or sidewalks.
- For a section of the project, the Company was requested by the state to partially restore the road surface as it would be affected again with the continuation of a state road project.

* Information reported as of December 18, 2015.

Observations by Project

#7365 2391 - Caldwell Avenue Replacement Project

Project Description

This project involved installing both steel and plastic mains along the berm of a state road, as well as some medium density plastic pipe along the side walk.

Figures*

Main Footage Installed:	5,809’
Total Project Costs:	$2,313,562
Paving / Sidewalk Repair Charges:	$518,291
Permitting Charges:	$2,493
Total Restoration Charges:	$520,784
Total Restoration as a percentage of project costs:	~23%
Applicable Specifications:	PennDOT

Field Personnel Commentary

- The scope of the project involved installing pipe primarily alongside the roadway and berm. Therefore, restoration required was less substantial than other projects involving pipe installation under roads or sidewalks.
- Installation of service lines warranted field personnel to mill and overlay affected road “curb to curb.”
- Due to the timing of the project, cold temperatures prevented the final wearing course of asphalt. Therefore, completion of restoration was delayed until months later in the following spring.
- Installing pipe up to a regulator station meant disrupting a church driveway and section of the parking lot. Costs to restore were minimal.

* Information reported as of December 18, 2015.

Observations by Project

#7321 Bower Hill Road Area Replacement Project

Project Description

This project involved the installation of plastic pipe in road rights-of-way in a populated residential area. A substantial majority of the project was in the Mt. Lebanon jurisdiction and only a small portion involving a county road fell under PennDOT specifications.

Figures*

Main Footage Installed:	8,320’
Total Project Costs:	$2,151,234
Paving / Sidewalk Repair Charges:	$829,191
Permitting Charges:	$28,345
Total Restoration Charges:	$857,536
Total Restoration as a percentage of project costs:	~40%
Applicable Specifications:	PennDOT Mt. Lebanon

Field Personnel Commentary

- As much of this project was situated within the Mt. Lebanon jurisdiction, several streets were restored “curb to curb” in accordance with municipal restoration specifications.
- For sections of the project where the use of pin and dowel restoration was not permitted, several concrete slabs were replaced where road cuts had been made in accordance with municipal restoration specifications.
- Several intersections were affected and required restoring all sidewalk corners to current ADA compliant standards.
- Due to the timing of this project, the amount of traffic, safety concerns, and weather conditions, the Company had to install temporary concrete on approximately a 500' section of ditch.

* Information reported as of December 18, 2015.

Observations by Project

#7357 PM D-88 Beaver River Crossing

Project Description

This project involved a major river bore and there was no restoration charged.

Figures*

Main Footage Installed:	1,508'
Total Project Costs:	$1,989,758
Paving / Sidewalk Repair Charges:	$0
Permitting Charges:	$19,232
Total Restoration Charges:	$19,232
Total Restoration as a percentage of project costs:	~10%
Applicable Specifications:	n/a

Field Personnel Commentary

- The D-88 River Bore went under both the CSX and Norfolk Southern Railroads. The staging area for the boring equipment was at the end of a city street adjacent to the CSX Railroad. The affected gravel road where the boring equipment was operated did not require pavement restoration.
- It was noted permitting charges above include $12,300 for a Norfolk Southern Railway Company license fee.

* Information reported as of December 18, 2015.

Observations by Project

#7397 2391 - McDonald (Final Phase)

Project Description

This project involved installation down a crowded main street. A significant section of the project was on SR 980.

Figures*

Main Footage Installed:	10,088’
Total Project Costs:	$1,919,229
Paving / Sidewalk Repair Charges:	$230,949
Permitting Charges:	$423
Total Restoration Charges:	$231,372
Total Restoration as a percentage of project costs:	~12%
Applicable Specifications:	PennDOT McDonald Borough

Field Personnel Commentary

- For a section of the project, restoration included a one foot cutback from the affected area (including base and asphalt replacement). Additional restoration was not required as the road had not been paved within the last five years.
- For a section of the project, the Company installed pipe under the sidewalk, necessitating concrete sidewalk restoration and minimal asphalt.
- For some areas, the Company was able to share restorations costs with the borough of McDonald as the project coincided with a previously planned road project.

* Information reported as of December 18, 2015.

Observations by Project

#7367 Emlenton Borough MP Upgrade Phase II

Project Description

This project involved the installation of 2” and 4” plastic mains. Over half of the project involved installation in the road while the remainder was under the sidewalks and grass adjacent to the roadways.

Figures*

Main Footage Installed:	12,367’
Total Project Costs:	$1,801,793
Paving / Sidewalk Repair Charges:	$964,784
Permitting Charges:	$0
Total Restoration Charges:	$964,784
Total Restoration as a percentage of project costs:	~54%
Applicable Specifications:	PennDOT Emlenton Borough

Field Personnel Commentary

- Project involved restoration of affected sidewalks to current ADA specifications. Handicap ramps requiring restoration during phase one and phase two were completed during and charged to phase two of the project.
- For main installations under several streets, Emlenton required restoration of entire street in accordance with municipal restoration specifications.
- For a section of the project, the Company split restoration costs with the water utility as their project similarly required disturbing the existing road.

* Information reported as of December 18, 2015.

Observations by Project

#7301 2421 - West Jackson Street

Project Description

This project involved the installation of 2” and 4” plastic mains. Previously, the old steel line was a low pressure line. The new main(s) were installed entirely in the sidewalk along the street with several road crossings.

Figures*

Main Footage Installed:	6,221’
Total Project Costs:	$810,224
Paving / Sidewalk Repair Charges:	$410,204
Permitting Charges:	$0
Total Restoration Charges:	$410,204
Total Restoration as a percentage of project costs:	~51%
Applicable Specifications:	York

Field Personnel Commentary

- Project involved many intersections and ADA compliance required all sidewalk corners to be reworked.
- The Company coordinated with the city of York for sections of the project as it overlapped a planned city road project. As a result, the Company completed restoration for curbs and sidewalks and installed a temporary layer of asphalt on affect roadway areas that would later be restored by the city.
- The Company worked with the area college and owners of properties along streets in scope of the project who coordinated additional work to be completed during restoration with upgrades such as stamped concrete and electric conduit for decorative street lighting installations in addition to the Company’s restoration efforts.

* Information reported as of December 18, 2015.

Observations by Project

#7395 2421 - York St, Hanover

Project Description

This project was on a state road, with a mix of installation in the street and in sidewalk, 2” and 6” plastic pipe, with several street crossings at intersections. It was an upgrade from a medium pressure system to a high pressure system but still had a low pressure system running on the other side of the street. There were also three low pressure jumpers in intersections.

Figures*

Main Footage Installed:	2,937’
Total Project Costs:	$595,058
Paving / Sidewalk Repair Charges:	$305,868
Permitting Charges:	$52
Total Restoration Charges:	$305,920
Total Restoration as a percentage of project costs:	~51%
Applicable Specifications:	PennDOT

Field Personnel Commentary

- As the state had planned to complete a road project the following spring, the Company restored affected roadways with base and a temporary driving layer of asphalt. Pipe installation involved both roadways and sidewalks as circumstances required. Where sidewalk corners were affected, the Company restored all corners of the intersection to be ADA compliant.
- During installation, the Company encountered numerous underground storage tanks which were removed in accordance with applicable environmental standards and required additional restoration.
- The populated area within the scope of the project required hundreds of service lines to be installed. Due to safety concerns with other utilities underground, the Company did not use trenchless technology.
- Many of the curbs had to be restored as they were very old and deteriorated and in order to restore the road properly, curbs had to be installed to an appropriate height. Replacing curbs can also sometimes require replacing adjacent sidewalks to meet specification.

* Information reported as of December 18, 2015.

Selected 2013 CPA Restoration Projects Audit

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2019 Company	Gross Residential Billings	Gross Residential Write-Offs	Gross Res. Write-Offs Ratio	Ranking of Gross Write off ratio (as a Percentage of Billings)	Residential Recoveries	Net Residential Write-Offs	Net Res. Write-Offs Ratio	Residential Recovery Rate	Ranking of Recovery Rate	Residential Customers	Not on Agreement Overdue Customer	Not on Agreement Overdue Percent	Not on Agreement Dollars Overdue	Not on Agreement Average Arrearage
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Duquesne	$ 554,560,188	$ 14,436,076	2.60%	7	$ 6,194,645	$ 8,241,431	1.49%	42.91%	1	538,534	63,023	11.70%	$ 10,388,819	$ 164.84
Met.Ed.	$ 613,381,575	$ 14,939,366	2.44%	5	$ 2,425,578	$ 12,513,788	2.04%	16.24%	10	504,685	77,113	15.28%	$ 16,801,748	$ 217.88
PECO	$ 2,497,022,637	$ 30,645,751	1.23%	1	$ 10,732,227	$ 19,913,524	0.80%	35.02%	5	1,505,328	253,428	16.84%	$ 61,084,925	$ 241.03
Penelec	$ 566,400,530	$ 15,212,941	2.69%	8	$ 2,623,602	$ 12,589,339	2.22%	17.25%	9	500,877	78,548	15.68%	$ 19,063,551	$ 242.70
Penn Power	$ 183,772,688	$ 3,448,167	1.88%	2	$ 480,808	$ 2,967,359	1.61%	13.94%	12	146,018	18,806	12.88%	$ 4,863,621	$ 258.62
PPL	$ 2,002,641,111	$ 51,249,852	2.56%	6	$ 18,898,493	$ 32,351,359	1.62%	36.88%	4	1,233,837	126,859	10.28%	$ 49,582,822	$ 390.85
West Penn Pwr	$ 695,021,554	$ 16,109,498	2.32%	4	$ 2,411,318	$ 13,698,180	1.97%	14.97%	11	627,499	86,477	13.78%	$ 19,308,743	$ 223.28
ELECTRIC	**$ 7,112,800,283**	**$ 146,041,651**	**2.05%**		**$ 43,766,671**	**$ 102,274,980**	**1.44%**	**29.97%**		**5,056,778**	**704,254**	**13.93%**	**181,094,229**	**$ 257.14**
Columbia	$ 431,312,024	$ 8,903,865	2.06%	3	$ 3,620,296	$ 5,283,569	1.22%	40.66%	2	400,044	26,165	6.54%	$ 3,674,251	$ 140.43
NFG	$ 146,182,599	$ 4,166,463	2.85%	9	$ 1,215,155	$ 2,951,308	2.02%	29.17%	7	196,778	14,826	7.53%	$ 3,512,520	$ 236.92
Peoples	$ 301,742,334	$ 9,322,215	3.09%	11	$ 594,700	$ 8,727,515	2.89%	6.38%	14	335,583	36,549	10.89%	$ 6,693,711	$ 183.14
Peoples-Equitable	$ 216,474,649	$ 6,626,698	3.06%	10	$ 477,646	$ 6,149,052	2.84%	7.21%	13	247,801	29,335	11.84%	$ 4,848,755	$ 165.29
PGW	$ 537,592,266	$ 32,545,577	6.05%	14	$ 6,348,616	$ 26,196,961	4.87%	19.51%	8	480,347	98,228	20.45%	$ 39,467,937	$ 401.80
UGI-Gas	$ 259,406,139	$ 10,153,148	3.91%	13	$ 3,368,425	$ 6,784,723	2.62%	33.18%	6	367,175	43,507	11.85%	$ 6,240,914	$ 143.45
UGI-Penn Natural	$ 164,890,204	$ 5,893,436	3.57%	12	$ 2,260,134	$ 3,633,302	2.20%	38.35%	3	157,025	18,289	11.65%	$ 3,613,853	$ 197.60
GAS	**$ 2,057,600,215**	**$ 77,611,402**	**3.77%**		**$ 17,884,972**	**$ 59,726,430**	**2.90%**	**23.04%**		**2,184,753**	**266,899**	**12.22%**	**$ 68,051,941**	**$ 254.97**
TOTAL	**$ 9,170,400,498**	**$ 223,653,053**			**$ 61,651,643**	**$ 162,001,410**				**7,241,531**	**971,153**		**$ 249,146,170**	

2019 Company	Not on Agreement Weighted Arrearage	Agreements Overdue Customers	Agreements Overdue Percent	Agreements Dollars Overdue	Agreements Average Arrearage	Agreements Weighted Arrearage	Percent of Dollars in Agreements	Ranking by highest Percentage of Total Dollars Overdue on	Percent of Overdue Cust. in Agreements	Total Overdue Customers	Residential Customers	% of Customers in Debt	Ranking by % of Customers in Debt	Total Dollars Overdue	Total Weighted Arrearage
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
Duquesne	1.92	12,898	2.40%	$ 12,610,523	$ 977.71	11.37	54.83%	4	16.99%	75,921	538,534	14.10%	3	$ 22,999,342	3.52
Met.Ed.	2.15	25,555	5.06%	$ 16,187,843	$ 633.45	6.25	49.07%	6	24.89%	102,668	504,685	20.34%		$ 32,989,591	3.17
PECO	2.29	23,838	1.58%	$ 15,663,192	$ 657.07	6.24	20.41%	14	8.60%	277,266	1,505,328	18.42%	4	$ 76,748,117	2.63
Penelec	2.58	27,131	5.42%	$ 18,095,576	$ 666.97	7.10	48.70%	7	25.67%	105,679	500,877	21.10%		$ 37,159,127	3.74
Penn	2.46	6,416	4.39%	$ 4,529,286	$ 705.94	6.73	48.22%	8	25.44%	25,222	146,018	17.27%	9	$ 9,392,907	3.55
PPL	2.94	69,227	5.61%	$ 34,653,397	$ 500.58	3.77	41.14%	9	35.30%	196,086	1,233,837	15.89%	7	$ 84,236,219	3.23
West Penn Pwr	2.40	26,519	4.23%	$ 19,437,991	$ 732.98	7.89	50.17%	5	23.47%	112,996	627,499	18.01%	10	$ 38,746,734	3.69
ELECTRIC	**2.51**	**191,584**	**3.79%**	**$ 121,177,808**	**$ 632.50**	**6.17**	**40.09%**		**21.39%**	**895,838**	**5,056,778**			**$ 302,272,037**	**3.29**
Columbia	1.46	16,875	4.22%	$ 11,265,336	$ 667.58	6.93	75.41%	1	39.21%	43,040	400,044	10.76%	1	$ 14,939,587	3.60
NFG	3.70	15,584	7.92%	$ 1,929,704	$ 123.83	1.93	35.46%	10	51.25%	30,410	196,778	15.45%	6	$ 5,442,224	2.79
Peoples	2.38	10,014	2.98%	$ 2,917,780	$ 291.37	3.79	30.36%	11	21.51%	46,563	335,583	13.88%	2	$ 9,611,491	2.68
Peoples-Equitable	2.21	7,447	3.01%	$ 2,098,598	$ 281.80	3.77	30.21%	12	20.25%	36,782	247,801	14.84%	4	$ 6,947,353	2.53
PGW	4.41	19,211	4.00%	$ 12,329,444	$ 641.79	7.05	23.80%	13	16.36%	117,439	480,347	24.45%		$ 51,797,381	4.84
UGI-Gas	2.18	12,980	3.54%	$ 9,958,860	$ 767.25	11.68	61.48%	3	22.98%	56,487	367,175	15.38%	5	$ 16,199,774	4.37
UGI-Penn Natural	2.18	7,322	4.66%	$ 6,344,968	$ 866.56	9.58	63.71%	2	28.59%	25,611	157,025	16.31%	8	$ 9,958,821	4.30
GAS	**3.19**	**89,433**	**4.09%**	**$ 46,844,690**	**$ 523.80**	**6.56**	**40.77%**		**25.10%**	**356,332**	**2,184,753**			**$ 114,896,631**	**4.04**
TOTAL		**281,017**		**$ 168,022,498**						**$ 1,252,170**	**7,241,531**			**$ 417,168,668**	

2019 Company	Termination s	Termination Percent per Customer	Ranking by terminations per customer	Reconnection s	Reconnect Ratio	Average Heating Bill	Average Non-Heating Bill	Average Total Bill	% of Billings In Debt	Collections Operating Expenses
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Duquesne	27,688	5.14%	10	21,468	77.54%	$ 109.00	$ 84.00	$ 85.96	4.15%	$ 7,811,163
Met.Ed.	26,076	5.17%	11	22,325	85.62%	$ 129.00	$ 91.00	$ 101.30	5.38%	$ 17,588,515
PECO	92,977	6.18%		78,866	84.82%	$ 105.01	$ 105.42	$ 105.30	3.07%	$ 16,941,442
Penelec	21,065	4.21%	8	16,095	76.41%	$ 124.00	$ 88.00	$ 93.98	6.56%	$ 17,499,436
Penn Power	4,293	2.94%	3	3,449	80.34%	$ 152.00	$ 93.00	$ 104.93	5.11%	$ 4,199,273
PPL	53,340	4.32%	13	39,001	73.12%	$ 166.44	$ 113.41	$ 132.91	4.21%	$ 9,104,260
West Penn Pwr	19,743	3.15%	4	15,308	77.54%	$ 122.00	$ 83.00	$ 92.91	5.57%	$ 18,310,785
ELECTRIC	**$ 245,182**	**4.85%**		**196,512**	**80.15%**	**$ 129.64**	**$ 93.98**	**$ 102.47**	**4.25%**	**$ 91,454,874**
Columbia	10,770	2.69%	1	6,153	57.13%	$ 97.00	$ 38.00	$ 96.29	3.46%	$ 5,042,206
NFG	7,533	3.83%	7	4,926	65.39%	$ 64.35	$ 32.42	$ 64.09	3.72%	$ 522,372
Peoples	11,255	3.35%	5	7,648	67.95%	$ 77.25	$ 25.15	$ 76.98	3.19%	$ 2,548,096
Peoples-Equitable	9,444	3.81%	6	6,598	69.86%	$ 75.01	$ 21.14	$ 74.77	3.21%	$ 1,720,406
PGW	29,048	6.05%	12	20,986	72.25%	$ 92.83	$ 43.13	$ 91.05	9.64%	$ 2,665,563
UGI-Gas	10,657	2.90%	2	7,825	73.43%	$ 68.53	$ 24.46	$ 65.69	6.24%	$ 5,284,248
UGI-Penn Natural	6,652	4.24%	9	4,839	72.75%	$ 92.86	$ 24.29	$ 90.45		$ 2,693,930
GAS	**85,359**	**3.91%**		**58,975**	**69.09%**	**$ 81.12**	**$ 29.80**	**$ 79.90**	**5.58%**	**$ 20,476,821**
TOTAL	**330,541**			**255,487**						**$ 111,931,695**

Energy Burden Study (whichever is sooner), Columbia will make such filing as required by the Energy Burden Study to modify or change its CAP rate selection. Columbia will serve a copy of this filing on all parties to this proceeding. In the interim, Columbia agrees to conduct a bi-annual review of accounts enrolled on the average of payments and percent of bill CAP payment plan options that exceed the maximum energy burden recommended by the Commission in the CAP Policy Statement. The Company will change each account to a lower payment plan option, if available.

58. To the extent terms of the settlement warrant changes to the Company's USECP, within 90 days of receiving a final order in this proceeding, the Company will submit a Petition to the Commission to modify its USECP consistent with the provisions of this Settlement.

59. Other universal service issues raised by CAUSE-PA, CAAP and OCA, not addressed by this Settlement, shall be presented to Columbia's USAC for discussion and identification of potential solutions.

D. NATURAL GAS SUPPLIER ISSUES

60. Within sixty (60) days of the filing of a settlement in this proceeding, Columbia shall convene a collaborative (Collaborative-I) with the parties to this proceeding and all interested General Delivery Service customers/Suppliers on its system to discuss operational and/or rule and tariff changes relative to operational orders, delivery quantities, and supplier access to customer usage information which would be in lieu of the current installation of the C&I Network.

(a) Such operational and/or rule/tariff changes could include, but would not be limited to:

(i) A revised operational order process for customers with daily read meters. Specifically, Columbia proposes that on an annual basis customers with daily read meters, or their agents, shall have the right to elect to be subject to Operational Flow Orders ("OFOs"), rather than Operational Matching Orders ("OMOs"), on days when operational orders are issued. Daily metered customers or their agents that elect to be subject to OFOs will be required to schedule supplies equal to the percentage of the customer's Maximum Daily Quantity ("MDQ") called by Columbia, subject to the provisions of Elective Balancing Service ("EBS") and Columbia's Rules Applicable to Distribution Service.

(ii) A revised method for establishing MDQs, which may include the use of multiple years of usage data and/or design day usage and creating a more uniform methodology as between sales and transportation customers.

(iii) Parameters for establishing the needed % of MDQ to satisfy OFOs, with timelines and triggers for the elimination or amelioration of the OFO.

In addition, the Collaborative-I will also consider ways in which to improve the accuracy and timeliness of customer usage data including installing telemetering or equivalent equipment.

61. Within 150 days of convening Collaborative-I, Columbia will file tariff changes to implement the solutions which Columbia and a general consensus of the participants (but not necessarily all) agree to. All parties retain their rights to support or oppose the tariff filing.

62. If: (1) despite the good faith efforts of participants no tariff is filed within the timeline set forth above (or any extension to which all collaborative participants

agree); or (2) a tariff is filed that is not supported by Direct Energy; or (3) the Commission does not approve the tariff filing, Direct Energy retains the right to file a complaint against Columbia with the sole issue being an allegation that Columbia has failed to comply with the C&I Network Installation provisions of the 2016 Rate Case Settlement and remedies for the alleged non-compliance. The Parties agree that they shall treat such complaint as if it were filed in the context of Columbia's rate case, including:

(a) Columbia shall retain the burden of proof to show that it has complied or should not be required to comply with the 2016 Settlement;

(b) The testimony and exhibits developed in the above proceeding will be used to resolve the complaint, with the right for Columbia to submit rejoinder testimony on the issue and the rights of parties to cross-examination;

(c) Neither Columbia nor any other Party shall raise any procedural objection to the complaint including, but not limited to an allegation that Direct has waived its right to raise this issue, a claim that the issue should have been raised in some other form or proceeding or a claim that no remedy can be provided because no Columbia rate case is pending; provided, however, that Columbia may continue to contend that implementation should be conditioned upon a Commission Order authorizing the recovery of C&I Network Installation costs; and

(d) All parties will request expedited treatment of the complaint.

63. Upon completion of the above Collaborative-I, Columbia shall continue to hold quarterly Collaborative Meetings (Collaborative-II) for a minimum of two years, and thereafter as appropriate, to which all parties to this proceeding, all interested Suppliers and representatives of interstate pipelines shall be invited. At these meetings,

Suppliers shall raise issues encountered on the Columbia system. Columbia shall also notify participants about any changes it is planning to make in GTS or Choice transportation rules. At the end of each meeting, Columbia shall produce minutes of the meeting consisting of a short summary together with action items, which shall be shared with all participants.

64. Columbia agrees to reduce the penalty multiple for violation of OMO/OFOs from three times to one and one half times. This change may be further reviewed in the collaborative as a component of alternative proposals for managing OFO/OMOs. If Columbia experiences substantially higher non-compliance with OFO/OMO requirements as a result of the lower multiplier, it reserves the right to seek to modify the penalty multiplier in a subsequent base rate case.

65. Columbia agrees to change the rate structure for bank balance transfers from a per unit fee to a flat $10 per transaction fee and gas transfers through the electronic bulletin board to a flat $15 per transaction fee.

E. OTHER

66. Except as otherwise modified by this Settlement, the Company's proposed tariff changes are approved, as set forth in Appendix "C".

F. RESERVED ISSUE FOR LITIGATION

67. Joint Petitioners have reserved for litigation the issue of whether Columbia will be permitted to continue to include on its bills a separate line item charge for non-commodity services elected by customers and offered by unaffiliated entities who are not NGSs, without being required to allow NGSs access to Columbia's bills to charge customers for non-commodity products and services that may be offered by NGSs.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2010-2215623
Office of Consumer Advocate	:	C-2011-2224941
Office of Small Business Advocate	:	C-2011-2224985
Columbia Industrial Intervenors	:	C-2011-2227004
The Pennsylvania State University	:	C-2011-2230067
Pennsylvania Communities Organizing for Change d/b/a ACTION United, Nettie Pelton and Carol Collington	:	C-2011-2232186
James Landis	:	C-2011-2224944
Marie Weaver	:	C-2011-2225050
Margaret Sentz	:	C-2011-2225828
Albert Jochen	:	C-2011-2225878
Patsy Orlando	:	C-2011-2227222
Maureen A. Doerr-Roman	:	C-2011-2231015
and	:	
Shipley Energy Company	:	
Dominion Retail, Inc.	:	
Interstate Gas Supply, Inc.	:	
Intervenors	:	
v.	:	
Columbia Gas of Pennsylvania, Inc.	:	

Pennsylvania Public Utility Commission	:	Docket Nos. R-2010-2201974
Office of Small Business Advocate	:	C-2010-2208133
Office of Consumer Advocate	:	C-2010-2208503
and	:	
Columbia Industrial Intervenors	:	
Intervenors	:	
v.	:	
Columbia Gas of Pennsylvania, Inc.	:	

JOINT PETITION FOR PARTIAL SETTLEMENT

TO ADMINISTRATIVE LAW JUDGE KATRINA L. DUNDERDALE:

I. INTRODUCTION

The Office of Trial Staff ("OTS") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), Columbia Industrial Intervenors ("CII"),[1] Dominion Retail, Inc. ("Dominion"), Shipley Energy Company ("Shipley"), Interstate Gas Supply, Inc. ("IGS"),[2] The Pennsylvania State University ("PSU"), Pennsylvania Communities Organizing for Change d/b/a ACTION United, Nettie Pelton and Carol Collington ("PCOC") and Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), parties to the above-captioned proceedings (hereinafter collectively referred to as the "Joint Petitioners"), hereby join in this Joint Petition for Partial Settlement ("Settlement") and hereby respectfully request that Administrative Law Judge Katrina L. Dunderdale ("ALJ Dunderdale" or the "ALJ") and the Commission expeditiously approve the Settlement as set forth below. The Settlement has been agreed to or not opposed by all active parties in this proceeding.[3]

As fully set forth and explained below, the Joint Petitioners have agreed to a settlement of all but two issues in the above-captioned general base rate proceeding (the "2011 Base Rate Filing"). The Settlement provides for increases in rates designed to produce $16.0 million in additional base rate revenue, and $1.0 million for increased funding for the Company's Low Income Usage Reduction Program ("LIURP") to be recovered from increases in charges under Columbia's Rider Universal Service Program ("Rider USP"), based upon the level of operations for the twelve months ending September 30, 2011, as adjusted for ratemaking purposes. The

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[1] CII's members are Glen-Gery Corporation, Harley-Davidson Motor Company, Knouse Foods Cooperative, Inc. and World Kitchen, LLC.

[2] For purposes of this Settlement, Dominion, Shipley and IGS are referred to collectively as the NGS Intervenors.

[3] PSU's joinder in this Settlement shall not be construed as supporting in any way the relief requested by some parties in paragraph 66. The OSBA is to be listed as not objecting to paragraphs 33, 36, 37 and 38(iii) of this Settlement. In addition, as explained below, six (6) individual Columbia customers filed Formal Complaints against the Company's proposed rate increase. However, these customers did not attend the Prehearing Conference, did not file testimony, and did not otherwise actively participate in this matter.. As indicated on the Certificate of Service, Columbia is serving a copy of the Settlement on these inactive customer complainants.

new rates are to become effective for service rendered on and after the date of the Commission's order approving the Settlement. In support of the Settlement, the Joint Petitioners state the following:

II. BACKGROUND

1. Columbia is a "public utility" and "natural gas distribution company" ("NGDC") as those terms are defined in Sections 102 and 2202 of the Public Utility Code, 66 Pa.C.S. §§ 102, 2202. Columbia provides natural gas distribution, sales, transportation, and/or supplier of last resort services to approximately 414,000 retail customers in portions of 26 counties of Pennsylvania.

2. On January 14, 2011, Columbia filed the above-captioned 2011 Base Rate Filing, together with Supplement No. 163 to its Tariff Gas – Pa. P.U.C. No. 9 ("Supplement No. 163"), responses to Commission filing requirements and standard data requests, and supporting direct testimony and exhibits. In the 2011 Base Rate Filing, Columbia proposed new tariff rules and regulations and proposed increased rates designed to produce an overall revenue increase of approximately $37.8 million annually based upon the *pro forma* level of operations for the twelve months ended September 30, 2011.

3. Supplement No. 156 to Tariff Gas – Pa. P.U.C. No. 9 ("Supplement No. 156" or "BTU factor proceeding"), which proposed a BTU adjustment factor to Mcf billing, was filed with the Commission on September 29, 2010 at Docket No. R-2010-2201974, and was suspended to May 27, 2011 by Commission Order dated November 19, 2010 at R-2010-2201974. On January 20, 2011, Columbia filed a Motion to Consolidate Supplement No. 156 with the base rate filing. Further, Columbia agreed to voluntarily extend the effective date for Supplement No. 156 to coincide with the Company's base rate filing.

4. On January 24, 2011, Administrative Law Judge Katrina L. Dunderdale issued an order consolidating the BTU factor proceeding with the 2011 Base Rate Filing.

5. On February 3, 2011, the OSBA filed a Notice of Appearance, Formal Complaint and Public Statement, which was docketed at Docket No. C-2011-2224985.

6. On February 9, 2011, the OCA filed a Notice of Appearance, Formal Complaint and Public Statement, which was docketed at Docket No. C-2011-2224941.

7. On February 14, 2011, the Company filed with the Commission Supplement No. 164 to Tariff Gas Pa. P.U.C. No. 9 ("Supplement No. 164"). Supplement No. 164, issued February 14, 2011 with an effective date of March 15, 2011, suspended the proposed rates contained in Tariff Supplement No. 163 until March 18, 2011, to permit further time for the Commission to adopt its Investigation Order.

8. On February 15, 2011, the NGS Intervenors filed a Petition to Intervene.

9. On February 18, 2011, CII filed a Formal Complaint, which was docketed at Docket No. C-2011-2227004.

10. PSU filed a Formal Complaint on March 4, 2011, which was docketed at Docket No. C-2011-2230067.

11. On March 14, 2011, Columbia served Supplemental Direct Testimony and related exhibits of Mark R. Kempic, John J. Spanos, Marianne L. Schuster, Danny G. Cote and John M. O'Brien related to revisions to Future Test Year Plant Additions and income taxes.

12. On March 17, 2011, OTS filed a Notice of Appearance.

13. In an Order entered March 17, 2011, the Commission initiated an investigation of Columbia's proposed general rate increase. Supplement No. 163 was suspended by operation of law pursuant to Section 1308(d) of the Public Utility Code, 66 Pa.C.S. § 1308(d), for up to seven months or until October 18, 2011, unless permitted by Commission Order to become effective at

an earlier date. In its Investigation Order, the Commission also identified several areas of concern to be investigated and addressed by the parties in this proceeding.

14. On March 18, 2011, Columbia filed with the Commission Supplement No. 165 to Tariff Gas Pa. P.U.C. No. 9 ("Supplement No. 165"). Supplement No. 165, issued March 18, 2011 with an effective date of March 18, 2011, suspended the proposed rates contained in Tariff Supplement No. 163 until October 18, 2011.

15. On March 22, 2011, PCOC filed an Entry of Appearance and a Formal Complaint, which was docketed at Docket No. C-2011-2232186.

16. Columbia was served with Formal Complaints by the following customers: James Landis, Docket No. C-2011-2224944; Marie Weaver, Docket No. C-2011-2225050; Margaret Sentz, Docket No. C-2011-2225828; Albert Jochen, Docket No. C-2011-2225878; Patsy Orlando, Docket No. C-2011-2227222; and Maureen A. Doerr-Roman, Docket No. C-2011-22310105.

17. A prehearing conference was scheduled for March 23, 2011. Joint Petitioners who participated in the prehearing conference filed prehearing memoranda identifying potential issues and witnesses.

18. The initial Prehearing Conference was held as scheduled on March 23, 2011. At the prehearing conference, ALJ Dunderdale established the litigation schedule. The ALJ also set forth discovery rules, which included shorter response times than those provided in the Commission's regulations. See 52 Pa. Code §§ 5.341 *et seq.*

19. On March 24, 2011, the ALJ issued a Prehearing Order that confirmed the litigation schedule established at the Prehearing Conference.

20. On April 18, 2011, the ALJ issued an Order Scheduling Public Input Hearings in Columbia's service territory. Pursuant to this Order, one public input hearing was held on May

16, 2011 at 1:00 p.m. in Pittsburgh, Pennsylvania, and one public input hearing was held on May 16, 2011 at 6:00 p.m. in Beaver Falls, Pennsylvania.

21. The Joint Petitioners conducted substantial formal and informal discovery in this proceeding. Pursuant to the established litigation schedule, OTS, OCA, OSBA, CII, PSU, PCOC and the NGS Intervenors distributed direct testimony and exhibits on April 25, 2011.

22. OTS provided supplemental direct testimony on May 13, 2011.

23. Columbia, OCA, OSBA, PSU, PCOC and the NGS Intervenors distributed rebuttal testimony and exhibits on May 20, 2011.

24. On May 25, 2011, PCOC filed an Application for Issuance of a Subpoena to the Department of Public Welfare ("DPW").

25. On June 1, 2011, surrebuttal testimony and exhibits were distributed by Columbia, OCA, OSBA, OTS, PSU, PCOC, CII and the NGS Intervenors.

26. On June 2, 2011, Columbia filed an unopposed Motion for Protective Order.

27. On June 3, 2011, ALJ Dunderdale issued a Protective Order for this consolidated proceeding.

28. By letter dated June 3, 2011, DPW responded to PCOC's Application for Issuance of a Subpoena.

29. On June 6, 2011, Columbia and OCA filed letter responses to the PCOC Application for Issuance of a Subpoena. In addition, PCOC filed a notice of withdrawal of its Application for Issuance of a Subpoena.

30. On June 9, 2011, Columbia distributed Rejoinder Testimony and exhibits. In addition, OCA distributed Supplemental Rebuttal Testimony and exhibits.

31. The Joint Petitioners held numerous settlement discussions over the course of this proceeding. As a result of those discussions and the efforts of the Joint Petitioners to examine

the issues in the proceeding, a settlement in principle of all but two issues was achieved by the Joint Petitioners, thereby negating the need for the scheduled evidentiary hearings on most issues. The Parties subsequently agreed to waive cross-examination on the two issues that remain in dispute. Therefore, the Joint Petitioners requested the ALJ hold a hearing to allow for the introduction and admission into evidence of Columbia's filing, testimony and exhibits and the testimony and exhibits filed by the other parties during the course of the proceeding, and to rule on admission of DPW's letter response to PCOC's subpoena. The hearing was held before the ALJ on June 10, 2011.

32. The Joint Petitioners have been able to agree to the Settlement covering all but two issues in the proceeding. The two issues reserved for litigation concern rate design for residential customers and PCOC's challenge to Columbia's existing Customer Assistance Program ("CAP") Plus model. Joint Petitioners have agreed to a base rate increase, to an allocation of that revenue increase to the rate classes and to rate design for the non-residential rate classes to recover the portion of the rate increase allocated to such classes. The Joint Petitioners are in full agreement that the Settlement is in the best interests of Columbia and its customers.

33. In the Settlement, the Joint Petitioners have proposed that rates be designed to produce an additional $17.0 million in annual operating revenues instead of the Company's filed increase request of about $37.8 million.

34. The Settlement terms are set forth in the following Section III.

III. SETTLEMENT

35. The following terms of this Settlement reflect a carefully balanced compromise of the interests of all the Joint Petitioners in this proceeding. The Joint Petitioners unanimously agree that the Settlement, which resolves all but the two issues previously identified, is in the

public interest. The Joint Petitioners respectfully request that the 2011 Base Rate Filing, including those tariff changes included in Supplement No. 163 and specifically identified in Appendix "C" attached hereto, be approved subject to the terms and conditions of this Settlement specified below:

A. REVENUE REQUIREMENT

36. Rates will be designed to produce an increase in operating revenues of $17.0 million based upon the pro forma level of operations at September 30, 2011.

37. Commencing with the effective date of rates in this proceeding, Columbia shall convert from flow through to normalization accounting procedures with respect to the benefits of the tax repairs deduction. In addition, with regard to the $37,487,634 tax refund previously received by Columbia that is attributable to the change in method for the repairs deduction, commencing with the effective date of rates in this proceeding, the remaining amount of $33,557,479 million shall be amortized over 2.25 years, rather than the current 10 year pass back period. This accelerated amortization results in an annual reduction of $14,914,435 million to the Company's claimed income tax expense. The amortization shall continue to be without interest and without a deduction of the unamortized balance from rate base. Any change in the refund amount, above or below the $37,487,634, shall be reflected in accumulated deferred income taxes to be created under the normalization method adopted by this Settlement.

38. Columbia will be permitted to recover the amortization of costs related to the following:

i. Long Wall Mining – Continuation of previously-approved five year amortization of the total amount of $266,189 related to long wall mining costs that began on October 28, 2008.

ii. Blackhawk Storage – Continuation of the previously-approved 24.5 year amortization of the total amount of $398,865 to be included on books and in rate base as a regulatory asset to reflect the total original cost that began on October 28, 2008.

iii. Tax Credit – Amortization of the unamortized portion of the $37,487,634 total tax credit ($33,557,479) at $14,914,435 per year for 2.25 years as per the Company's Supplemental Direct Testimony beginning upon implementation of rates approved at this Docket.

39. Commencing with the effective date of rates, Columbia will be permitted 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 $1,898,955. Only those amounts attributable to operation and maintenance would be deferred and recognized as a regulatory asset or liability. Amounts recorded as a regulatory asset or liability will be collected from or returned to customers in the next rate proceeding. Columbia will report the deferrals in its next base rate filing. In addition, rates reflect the amortization of deferred OPEB amounts to be refunded of $1,500,000 annually.

40. Columbia will continue to deposit into irrevocable trusts the gross annual OPEB accrual. This amount includes the annual expense calculated by its actuary pursuant to ASC 715 and the annual amortization of the transition obligation. If annual amounts deposited into 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.

B. REVENUE ALLOCATION AND RATE DESIGN

41. Revenue allocation shall be as set forth in Appendix "A." Rate design for all classes other than residential rate classes shall be as set forth in Appendix "B." Revenue allocation and non-residential rate design reflect a compromise, and do not endorse any particular cost of service study result.

42. This Settlement resolves all revenue requirement and universal service issues except the challenge by PCOC to Columbia's continued use of CAP-Plus, which remains at issue. The Settlement also does not resolve issues related to residential rate design.

43. It is agreed that Commission resolution of the issues that continue to be litigated does not and shall not affect or otherwise alter the agreed upon revenue requirement amount identified in this Settlement.

44. Both the Company and OTS residential rate design proposals increase revenue stability with the Company proposal providing for a greater degree of stability. As such, the adoption of either would give rise to a corresponding adjustment to the cost of common equity to reflect such increased stability.

45. OTS and Columbia have considered the effects of such increased revenue stability in establishing the revenue requirement in this proceeding.

46. As stated in paragraph 68 below, the issues related to residential rate design continue to be fully litigated and detailed positions on those issues have been placed on the record by a number of parties to this proceeding.

C. DTH BILLING

47. Columbia currently bills customers on an Mcf basis. As part of its filing in the BTU factor proceeding, Columbia proposed to adjust customers' Mcf billings by a BTU factor adjustment, to reflect the relative heat content of gas used by customers in different areas of

Columbia's service territory. In addition, as part of its filing in this case, Columbia forecasted its future test year volumes based on a heat factor of 1.097 Dth per Mcf. Subject to the continued litigation of residential rate design as stated in paragraph 68, Columbia accepts OCA's proposal to bill base rates and commodity costs on a Dth basis, in lieu of the adjustment mechanism proposed by the Company in its filing. Under the OCA method, the Dth per Mcf conversion will be determined for each Pipeline Scheduling Point ("PSP") area on a monthly basis, and applied to the volumetric (Mcf) meter read for each customer in each PSP in each month. To provide time for education of customers and conversion to Dth billing, Dth billing shall begin no later than with bills rendered June 2012. Prior to implementing the billing unit change, Columbia will work with the Parties to reconcile the data Columbia uses to measure gas received and the throughput data Columbia uses for rate design and billing – system-wide and by PSP area. Rates from the effective date of the Commission's final order until the commencement of Dth billing will be on an Mcf basis, without a BTU adjustment applied to customers' bills. The Company will submit compliance tariffs both on an Mcf and a Dth basis.

i. Pro forma future test year volumes on an Mcf Basis as presented by Columbia will be revised to reflect 1.073 Dth per Mcf, based on the actual heat content in the historical year, and rates will be developed on these volumes. These volumetric rates will apply during the interim period, ending by June 2012, while Columbia is converting to Dth billing and educating its customers about the billing change. For non-residential customers, these volumes and rates are shown in Appendix B.

ii. The base rates on a Dth basis will be designed on billing units reflecting Columbia's pro forma test year billing units as set forth in subpart i, with the

Mcf quantities converted to Dth at 1.073 Dth per Mcf. These rates will apply to Dth billing, which will begin (as stated above) no later than June 2012.

D. UNIVERSAL SERVICE AND CONSERVATION

48. Columbia withdraws its proposal to implement its Safe at Home Senior Program, its Senior Universal Service Program ("USP") Rider Waiver and its Senior Flexible Due Date Program.

49. Any changes in the CAP Plus approach, including programming changes, will be reflected under Columbia's Universal Service Rider.

50. Commencing with 2012, Columbia will implement a two-year pilot program ("Pilot") to evaluate all CAP customers with a CAP credit of $1,000 or more ("Maximum CAP Credit"). The initial Maximum CAP Credit of $1,000, effective January 1, 2012 will be adjusted each January 1, commencing January 1, 2013, to reflect the percentage increase or decrease in PGC rates approved for the period commencing on October 1 of the immediately preceding year as compared to PGC rates that become effective October 1, 2011. The Maximum CAP Credit shall also be adjusted for any increase in base rates subsequent to the increase in base rates in these consolidated proceedings.

51. Upon commencement of the Pilot, Columbia will evaluate each CAP customer that exceeds the Maximum CAP Credit. Columbia will review the list for customers with the highest consumption that have not received weatherization services through Columbia's Low Income Usage Reduction Program ("LIURP"). Columbia will prioritize those customers for weatherization within the parameters of Columbia's LIURP. Columbia will survey the remaining customers to determine the existence of any control limit exceptions as defined in the CAP policy statement. The 200 highest users that have received LIURP weatherization, and to whom a valid control limit exception does not apply, will be referred to the Remedial Energy

Efficiency Program ("REEP" – previously known as "HURP") in Columbia's approved Universal Service and Energy Conservation Plan. After twelve months of participation in the REEP, any customers who have not reduced their consumption will have their CAP payments raised. Columbia will review the remaining accounts that do not qualify with a valid exception individually, and raise payments such that the CAP discount for the next twelve month period is projected to be less than the Maximum CAP Credit.

52. Columbia will provide a status report once the survey is completed, which will include the number of customers who fall within the three categories identified above. Then, Columbia will track the customers in each category, and one year after the survey, Columbia will provide a report on all Pilot customers' current account status and any program consumption savings results. Columbia will provide an annual cost of the program including administrative costs, programming costs, as well as uncollectible expenses. All of the reports referred to in this paragraph will be served upon the parties of record in this proceeding.

53. At the end of two years, the Pilot will be evaluated on a cost benefit basis. All administrative costs for this Pilot will be recovered through the USP Rider.

54. There will be an increase in annual LIURP funding from $3,000,000 to $4,000,000, commencing with the effective date of rates in this proceeding. This $1 million increase in LIURP spending is reflected in the agreed-upon $17 million increase in operating revenue, as shown in Paragraph 36. LIURP funding will continue to be recovered under Rider USP. Any resulting unspent balance in the designated LIURP fund account shall carry over and shall remain in that account.

55. In recognition of the additional LIURP funding provided by this Settlement, Columbia withdraws the proposed Pilot Home Energy Efficiency Program at this time.

56. Columbia agrees that it will continue to waive late payment charges as to CAP customers and customers with incomes equal to or less than 150% of the Federal Poverty Level that enter into payment arrangements with Columbia, as long as such customers comply with such payment arrangements.

E. DSIC

57. Columbia withdraws its Rider DSIC proposal from this proceeding. However, Columbia reserves the right to propose a DSIC if authorized by the General Assembly, to reflect amounts not included in rate base in this proceeding. In calculating any future DSIC charge related to eligible facilities included in the six months immediately following the Future Test Year of this case, Columbia will deduct $11.6 million. That deduction will reflect the inclusion in rate base of CWIP as of September 30, 2011, in the calculation of revenue requirement under this Settlement. All Parties reserve the right to oppose any filing by Columbia proposing a DSIC and to challenge the details of how the DSIC will be calculated.

F. NATURAL GAS SUPPLIER ISSUES

58. Columbia agrees to raise the volumetric limit under Rate SCD – Small Commercial Distribution to 6,000 Mcf/year. Customer charges for Rate SCD will be the same as those for Rate SGSS as shown in Appendix B. Eligible customers will be permitted to switch between Small General Distribution Service ("SGDS") and Choice in accordance with the expiration and renewal terms of their existing General Distribution Agreement.

59. Columbia agrees to provide natural gas suppliers with a rescind file, which will notify suppliers if a newly enrolled distribution service customer has elected not to complete an enrollment within 10 days of signing up with a natural gas supplier.

60. Columbia agrees to provide on a monthly basis to each natural gas supplier actively serving customers on Columbia's system, without charge, a synchronization list (ACT file).

61. Columbia agrees to discuss the remaining administrative process/rules issues in a separate collaborative process with the NGS Parties to begin as soon as practical. For purposes of this provision the issues to be discussed will include: data retention, elimination of fees, discontinuance of "black-out dates", and drop the practice of check digits.

62. Columbia agrees to revise the cash in/ cash out adjustment factors as follows:

RADS SECTION:	UNDER	ADJUSTMENT
3.6.4(1)	0%-10%	120%
	10.01% AND OVER	130%
3.6.4(2)	OVER	
	0%-10%	80%
	10.01% AND OVER	70%
3.11.4	UNDER	
	0%-5.00%	105%
	5.01%-10%	110%
	10.01%-15.00%	120%
	15.01% AND OVER	130%
3.12.4	OVER	
	0%-5.00%	95%
	5.01%-10%	90%
	10.01%-15.00%	80%
	15.01% AND OVER	70%

63. Columbia agrees to limit the availability of Rate NSS to competitive situations, where a customer would not initiate service from Columbia or would no longer take service from Columbia, but for the availability of service under Rate NSS. Columbia agrees to transition existing NSS customers that are not in competitive situations to other services (Sales or Transportation) upon contract expiration but no later than July 1, 2012.

64. All other NGS Parties' proposals in this proceeding are withdrawn. In addition, the NGS Parties agree, individually and collectively, that for a period of thirty (30) months from the effective date of the final order in this case, they will not present any of the withdrawn proposals either through the filing of a separate complaint, petition or application, or through intervention in a base rate or other proceeding of Columbia.

65. Commencing with the effective date of rates in this proceeding, the unbundled gas cost portion of uncollectible accounts, also referred to as the uncollectible expense ratio for purposes of Columbia's Purchase of Receivables Program, shall be 1.52%. As a result, the discount rate for purchased Choice NGS receivables shall be 2.11% (1.52% + 0.59% administrative adder).

G. FLEXED RATES

66. Columbia agrees to join with OTS, OCA and/or OSBA in a request that the Commission initiate a generic investigation or rulemaking to address whether flex discounts solely as a result of competition from other NGDCs should be permitted to continue and, if permitted to continue, under what circumstances it will be considered appropriate. Other Parties reserve the right to challenge the necessity for any such investigation or rulemaking. The terms and conditions of this Settlement proposal are in no way conditioned upon the Commission commencing the requested generic investigation or rulemaking.

67. Columbia agrees to clarify the process to be used for affidavits related to flex rates, and to maintain requested customer information confidential as follows:

a) In implementing the provisions of Tariff Rule 20 - Flexible Rate Provisions, Columbia shall require that the customer provide the "all-in" burner tip price in its sworn affidavit for Columbia to evaluate whether a flexed rate should be offered to the customer. Columbia shall undertake its own review of the facts surrounding the customer's competitive alternatives to assess the reasonableness of the asserted price. In accordance with its tariff, if Columbia has questions concerning the reasonableness of the asserted price, Columbia reserves the right to verify the accuracy of statements included in this affidavit. Columbia commits that it will make initial requests to verify the accuracy of statements included in a customer's affidavit based on non-confidential information. To the extent that Columbia then requests additional confidential information, upon customer's written request, Columbia will have the ability to review such confidential information at the customer's place of business, but will not be permitted to remove documents containing confidential information from the customer's place of business. However, Columbia will be permitted to take notes of information provided to allow it to analyze the requested flex, subject to the confidentiality agreement below. In addition, Columbia affirmatively agrees that customer may redact all supplier identifying information prior to allowing the Company to review any confidential information. Further, Columbia shall agree to enter into a confidentiality agreement, which shall provide that: (1) the requested information is competitively sensitive, proprietary in nature, and confidential and will only be used for evaluating whether to extend a flexed rate offer to the customer; and (2) distribution of such confidential information shall be limited to only those employees involved with negotiating and approving flexed agreements. Columbia confirms that the employees involved with negotiating and approving flexed agreements will not provide any confidential information to the department responsible for pricing the Negotiated Sales Service.

b) Columbia shall not further release such information except where required as part of Commission proceedings, or where the law or a court requires disclosure. In the event Columbia is requested to disclose such information, Columbia shall advise the affected customer with as much advance notice as possible. If a customer refuses to provide requested information, Columbia may take such refusal into account in deciding whether to offer a flexed rate.

c) Columbia agrees that interested parties will have the ability to review and provide input regarding the above mentioned confidentiality agreement prior to finalizing same. Columbia recognizes that modifications to the pro forma confidentiality agreement may be necessary to meet individual customers' needs.

d) This process will not affect any statutory party's right to review and challenge Columbia's rate recovery of discounts from flex rate agreements in future cases.

H. RESERVED ISSUES FOR LITIGATION

68. The reserved issues for litigation are residential rate design and the challenge by PCOC to Columbia's continued use of CAP-Plus.

IV. SETTLEMENT IS IN THE PUBLIC INTEREST

69. This Settlement was achieved by the Joint Petitioners after an extensive investigation of Columbia's filing, including informal and formal discovery and the submission of direct, rebuttal, surrebuttal and rejoinder testimony by a number of the Joint Petitioners that were admitted into the record by stipulation.

70. Acceptance of the Settlement will avoid the necessity of further administrative and possibly appellate proceedings regarding the settled issues at what would have been a substantial cost to the Joint Petitioners and Columbia's customers.

71. Joint Petitioners have submitted, along with this Settlement, their respective Statements in Support setting forth the basis upon which each believes the Settlement to be fair, just and reasonable and therefore in the public interest. The Joint Petitioners' Statements in Support are attached hereto as Appendices "D" through "K".

V. CONDITIONS OF PARTIAL SETTLEMENT

72. This Settlement is conditioned upon the Commission's approval of the terms and conditions contained herein without modification. If the Commission modifies the Settlement, then any Joint Petitioner may elect to withdraw from this Settlement and may proceed with litigation and, in such event, this Settlement shall be void and of no effect. Such election to withdraw must be made in writing, filed with the Secretary of the Commission and served upon all Joint Petitioners within five (5) business days after the entry of any Order modifying the Settlement.

73. The Joint Petitioners acknowledge and agree that this Settlement, if approved, shall have the same force and effect as if the Joint Petitioners had fully litigated these proceedings resulting in the establishment of rates that are Commission-made, just and reasonable rates.

74. This Settlement and its terms and conditions may not be cited as precedent in any future proceeding, except to the extent required to implement this Settlement.

75. The Commission's approval of the Settlement shall not be construed to represent approval of any Joint Petitioner's position on any issue, except to the extent required to effectuate the terms and agreements of the Settlement in these and future proceedings involving Columbia.

76. It is understood and agreed among the Joint Petitioners that the Settlement is the result of compromise, and does not necessarily represent the position(s) that would be advanced by any Joint Petitioner in these proceedings if they were fully litigated.

77. This Settlement is being presented only in the context of these proceedings in an effort to resolve the proceedings in a manner which is fair and reasonable. The Settlement is the product of compromise between and among the Joint Petitioners. This Settlement is presented without prejudice to any position that any of the Joint Petitioners may have advanced and without prejudice to the position any of the Joint Petitioners may advance in the future on the merits of the issues in future proceedings except to the extent necessary to effectuate the terms and conditions of this Settlement. This Settlement does not preclude the Joint Petitioners from taking other positions in proceedings involving other public utilities under Section 1308 of the Public Utility Code, 66 Pa.C.S. § 1308, or any other proceeding.

78. The Joint Petitioners recognize that the proposed Settlement does not bind Formal Complainants that do not choose to join herein. A copy of the proposed Settlement and attached Appendices hereto, including Statements in Support, are simultaneously being served upon all Formal Complainants in this proceeding.

79. If the ALJ adopts the Settlement without modification, the Joint Petitioners waive their individual rights to file exceptions with regard to the Settlement. Joint Petitioners retain

their rights to file briefs, exceptions and replies to exceptions with respect to the two reserved issues for litigation.

WHEREFORE, the Joint Petitioners, by their respective counsel, respectfully request as follows:

1. That the Honorable Administrative Law Judge Katrina L. Dunderdale and the Commission approve this Settlement including all terms and conditions thereof, without modification;

2. That the Commission's investigation at PUC Dockets R-2010-2215623 and R-20102201974 and the complaints of OSBA, OCA, CII, PSU and PCOC at Docket Nos. C-2011-2224985, C-2011-2224941, C-2011-2227004, C-2011-2230067 and C-2011-2232186 shall be marked closed with respect to the settled issues;

3. That all customer complaints associated with this proceeding, including the Complaints of James Landis, Marie Weaver, Margaret Sentz, Albert Jochen, Patsy Orlando and Maureen A. Doerr-Roman, at Docket Nos. C-2011-2224944, C-2011-2225050, C-2011-2225828, C-2011-2225878, C-2011-2227222 and C-2011-2231015, respectively, be dismissed.

4. That the Commission enter an Order ruling on the reserved issues and authorizing Columbia Gas of Pennsylvania, Inc. to file a tariff or tariff supplement in compliance with the Commission's Order, effective for service rendered on and after the date of the Commission's Order.

Respectfully submitted,

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Date: June 30, 2011

COLUMBIA STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

August 26, 2020

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.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I respond to revenue allocation and rate design issues raised by Witness Ethan H. Cline on behalf of the Bureau of Investigation and Enforcement ("I&E"), Witnesses Jerome D. Mierzwa and Roger D. Colton on behalf of the Pennsylvania Office of the Consumer Advocate ("OCA"), Witness Robert D. Knecht on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"), Witness Mitchell Miller on behalf of The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), Witness Susan A. Moore on behalf of the Community Action Association of Pennsylvania ("CAAP") and Witness Frank Plank on behalf of the Columbia Industrial Intervenors ("CII"). I will also address a change to the effective billing cycle of the Company's proposal to reduce the Weather Normalization Adjustment ("WNA") deadband from 3 percent to 0 percent and a change to the implementation of the Revenue

Normalization Adjustment ("RNA"). Finally, I will address Columbia's response to the Commission directive in its Order issued on August 20, 2020 in this proceeding.

Q. Are you presenting any exhibits with your Rebuttal Testimony? If yes, please list the exhibits.

A. Yes. The list of exhibits included with this Rebuttal Testimony is shown below:

Exhibit Number	**Topic**
Exhibit MJB-1R:	Potential Conservation Savings with RNA
Exhibit MJB-2R:	Discovery Response I&E IV-001 to Columbia

Q. In your direct testimony, the Company proposed to implement the modified WNA effective with the February 2021 billing cycle[1]. What is the new proposed effective date of the modified WNA?

A. The Company submits that the proposal to reduce the WNA deadband from 3 percent to 0 percent become effective with the April 2021 cycle billing, based on the extended suspension period of February 24, 2021. The delay is needed in order for the Company to implement final rates once the Company's compliance tariff filing is approved, and to back-bill customers to January 23, 2021 for the delay in billing the final rates. I will discuss the back-billing of customers later in my rebuttal testimony.

Q. Please explain the proposed change to the RNA.

[1] Columbia Statement No. 3, Direct Testimony of Melissa J. Bell, page 25, line 10.

A. In my direct testimony, the Company proposed to begin tracking for the RNA beginning with the January 2021 billing month. The Company is proposing to begin tracking with the April 2021 billing month for the same reasons I previously mentioned for delaying the implementation in the modified WNA. Because the Company will not begin tracking for the RNA until April 2021, the initial filing for an RNA adjustment will be for the Off Peak Period, April 2021 through September 2021, effective in April 2022.

I. Response to Witness Ethan H. Cline

Q. What topics in Witness Cline's Direct Testimony are being addressed in this testimony?

A. This testimony addresses Witness Cline's Direct Testimony concerning Columbia's proposed Weather Normalization Adjustment ("WNA"), Revenue Normalization Adjustment ("RNA"), revenue allocation and scale back of revenue allocation.

Q. Does Witness Cline agree with Columbia's proposal to eliminate the 3 percent deadband?

A. No.

Q. In his Direct Testimony, page 9, lines 15-18, Witness Cline discusses his reasons for not eliminating the WNA's 3 percent deadband. He states, "I believe such a departure from traditional ratemaking should only occur due to circumstances that are an extraordinary departure from normal operating conditions, such as abnormal weather." Do you agree with Witness Cline that WNA is an extreme weather fix, only?

A. I do not agree that the only purpose of the WNA is to serve as an extreme weather fix, only. By design, the WNA calculation includes every daily temperature variation within a billing month, and not just "extreme days." The 3 percent deadband applies to the total for the billing month, so "extreme days" could be offset by small variances throughout the month.

Q. Please explain why Columbia has proposed to eliminate the deadband for the WNA.

A. Columbia agreed to the WNA deadband as part of a joint settlement agreement. The goal of the WNA is to eliminate revenue and bill variations due to warmer and colder than normal weather. Under the WNA, distribution rates billed to residential customers are reduced if winter weather is colder than normal and, correspondingly, increased if weather is warmer than normal. In a base rate proceeding, residential rates are set using normal weather. The WNA without a deadband provides a reasonable opportunity for the Company to bill the customer for revenues approved in a base rate proceeding by eliminating the effects of weather on a real time basis. If the deadband were allowed to continue, revenues billed within the deadband would not be fully adjusted for shifts in weather, and customers would be billed more or less than was intended by the Commission simply because of rate design. Having a deadband in place undermines the purpose of the WNA, which is the elimination of the impact of weather on the revenue requirement approved by the Commission. For instance, if the deadband is eliminated and the weather is 2.5 percent colder than normal, then the Company would be able to lower customers' bills, to reflect the abnormal weather. However, with a 3 percent deadband in place, those revenues would be retained by the Company.

Q. Is it possible to estimate how much a typical residential customer would be impacted by the WNA's 3 percent deadband, if actual weather was 2.5 percent colder than normal for a few months?

A. Yes. Refer to Tables MJB-1R and MJB-2R below:

Table MJB-1R

Year	Month	Normal Usage Dth	Customer Charge $23.00	Distribution Charge $7.3323	Distribution Bill (Normal)
2021	Jan	16.78	$23.00	$123.04	$146.04
2021	Feb	16.64	$23.00	$122.01	$145.01
2021	Mar	13.86	$23.00	$101.63	$124.63
Three Month Total		47.28			**$415.67**

Table MJB-2R

Year	Month	2.5% Colder Usage Dth	Customer Charge $23.00	Distribution Charge $7.3323	Distribution Bill 2.5% Colder
2021	Jan	17.17	$23.00	$125.90	$148.90
2021	Feb	17.03	$23.00	$124.87	$147.87
2021	Mar	14.18	$23.00	$103.97	$126.97
Three Month Total		48.37			**$423.74**

Q. Please explain the assumptions used to compute the distribution bills shown in Table MJB-1R and Table MJB-2R.

A. The normal monthly residential usage levels for January through March (2021), in Table MJB-1R, are taken from Exhibit No. 10, Schedule No. 2, page 8 of 8 sponsored by Company Witness Bikienga. In order to compute the monthly usage, given 2.5 percent colder than normal weather, the temperature-sensitive consumption for each month was multiplied by 1.025. This computation resulted in the monthly usage levels shown in Table MJB-2R. In both Tables MJB-1R and MJB-2R, monthly distribution bills were computed using Columbia's proposed residential rate design.

Q. In this scenario, how much more would a typical residential customer be billed for distribution service in the months of January through March due to the 2.5 percent colder than normal temperate and the 3% deadband?

A. Please refer to Table MJB-3R shown below:

Table MJB-3R

Year	Month	Distribution Bill Normal	Distribution Bill 2.5% Colder	Distribution Bill Difference
2021	Jan	$146.04	$148.90	$2.86
2021	Feb	$145.01	$147.87	$2.86
2021	Mar	$124.63	$126.97	$2.34
Three Month Total		$415.67	$423.74	**$8.07**

Table MJB-3R demonstrates that, assuming weather is 2.5 percent colder than normal, this typical residential customer would be billed $8.07 more for the months of January through March, as a result of the 3 percent WNA deadband.

Q. If the WNA deadband were to be eliminated, would this residential customer's bill be $8.07 lower for this three-month period?

A. Yes. This customer's bill would be lowered by $8.07 in real time.

Q. Is it in the interest of residential customers, along with Columbia to eliminate the 3 percent deadband?

A. Yes. For both residential customers and Columbia, elimination of the WNA deadband helps to further normalize bills for weather variations.

Q. Is there another reason that Columbia proposed to eliminate the WNA's 3 percent deadband?

A. Yes. By charging or crediting revenues for the full impact of weather, in real time, through the WNA, the Company's proposed RNA is limited to charging or crediting distribution revenues that deviate from test year revenues, exclusive of distribution revenues adjusted through the WNA. Because Rider WNA adjustments are based on each customer's individual usage behavior and are billed monthly, the adjustments occurring through the RNA would be less impactful to customers due to the existence of the WNA without a deadband.

Q. On page 11, lines 16 through 18 of his Direct Testimony, Witness Cline argues that the Company has not demonstrated the need for more revenue stability or indicated that the RNA will result in fewer base rate increases. Please comment on Witness Cline's statements.

A. Rate case timing is dependent upon many factors, including capital additions, fluctuations in the cost of capital and operations and maintenance expenses. The Company is not able to state with certainty that implementing a residential RNA would lead to fewer rate cases. However, the stability provided by the RNA is beneficial for both the Company and its residential customers, because the Company would credit or collect any distribution revenues over or under the benchmark revenue per customer that is established as part of a base rate proceeding.

Q. Please refer to page 11, lines 21 through page 12, line 10 of Witness Cline's Direct Testimony. On these lines, Witness Cline asserts that the proposed RNA can "cause harm." Do you agree?

A. No. Witness Cline makes two incorrect assumptions to support his assertion that the RNA can "cause harm." I will address both errors. First, on page 11 lines 21 and 22, he states, "In order for customers to benefit from the RNA, they would need to use more gas to trigger the refund, contrary to conservation efforts."

Q. Why is this statement flawed?

A. Witness Cline fails to recognize the many reasons that a residential customer's usage could increase. Granted, residential customers could make the decision to turn up the heat on a cold day. However, this would not help them to lower their bills, because they would pay for using the additional gas commodity. Additionally, residential customers' consumption patterns could change for other reasons. Perhaps a customer has decided to work at home and is raising the heat because the house will be occupied. This could also lead to the use of more hot water in the residence. Aside from additional usage related to existing appliances, a customer could decide to purchase a gas dryer or replace an electric water heater with a gas water heater. Increased usage for these reasons is not contrary to conservation efforts. Further, RNA adjustments, unlike WNA adjustments, are not calculated on a customer-specific basis, but rather on a class-wide basis.

Q. Please comment on Witness Cline's second error in this response.

A. On page 11, lines 22 through page 12 line 3 of Witness Cline's Direct Testimony, he states, "Customers who undertake conservation efforts will see their savings eroded and their investment payback time increase as the Company is permitted to increase rates in response to usage declines." This is simply not true. First, the RNA, unlike the WNA, does not result in real time billing adjustments. If a residential customer reduces consumption, unrelated to weather variations, then that customer will experience immediate savings on their bill. Secondly, the proposed RNA would reflect what normally happens in a rate case when customers implement conservation measures. If usage is reduced, then in the Company's next base rate case, fixed costs are spread over lower volumes, and rates for all residential customers would increase. Conservation savings from individual residential customers is spread among all residential customers.

Q. Please demonstrate how a residential customer's reduced usage, unrelated to weather variations, results in immediate and long-term savings on their bill with the Company's RNA proposal.

A. Refer to Exhibit MJB-1R 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-1R.

A. Column 4 of Exhibit MJB-1R shows normalized usage for an average residential customer for the Fully Projected Future Test Year, 2021, as presented by Company Witness Bikienga 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 $1,206.42 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 $175 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 $175 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 $175 would be reduced by about $17.50 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.

Q. On page 12, lines 4 through 6, of Witness Cline's Direct Testimony, Witness Cline states, "Further, customers who lack the financial means

to undertake conservation efforts will be penalized by the RNA, which increases rates to address usage reductions." Please comment on Witness Cline's statement.

A. Witness Cline portrays the RNA as one-sided. He has testified concerning usage reductions and bill increases. I would like to reiterate that the RNA is designed as a balanced rate adjustment mechanism. Under the proposed RNA, Columbia would either charge or return dollars due to variations from the revenue benchmarks approved as part of a general base rate proceeding. Also, as stated previously, Witness Cline is merely pointing out how the normal rate case process works. If usage decreases, then the Company's costs would need to be spread over fewer volumes for recovery.

Q. What does Witness Cline recommend concerning revenue allocation?

A. On page 16, lines 12 through 14 of Witness Cline's Direct Testimony., he states, "I recommend 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."

Q. Do you agree with relying on a single class cost of service study?

A. No. A single class cost study should not be relied upon for revenue allocation. Witness Notestone's studies produce a range of alternatives that can be used to benchmark or guide revenue allocation. The Customer/Demand Study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to industrial customers, while the Peak & Average Study (Exhibit N. 111, Schedule 2) produces results that are generally more favorable to residential customers.

Q. Why does the Company rely on the Average Study as a basis or guide to allocate revenue requirement?

A. The Average Study, as presented by Witness Notestone, in Exhibit No. 111, Schedule 3 is an average of the Customer/Demand Study and the Peak & Average Study. Columbia believes that the Customer/Demand Study and the Peak & Average Study provide a reasonable range of results. The Average Study, with its equal weighting of the two previously-mentioned studies, provides results that can be used as an appropriate benchmark or guide in revenue allocation. Please see Company Witness Notestone's Rebuttal Testimony (Columbia Statement No. 11-R) for detailed support of the Company's allocated cost of service approach.

Q. Are there area(s) of agreement between the Company and intervening parties concerning revenue allocation?

A. Yes. Generally, the I&E, OSBA and OCA agree that an Allocated Cost of Service Study or a range of Allocated Cost of Service Studies should be used, as a guide, in establishing revenue requirements by customer classes. However, there are different opinions concerning the most appropriate way to measure allocated costs. Company Witness Notestone addresses the claims raised by I&E, OCA and OSBA concerning cost allocation methodologies.

Q. Does Columbia continue to support the revenue allocation presented in Exhibit 103, Schedule 8?

A. Yes. Columbia continues to support its proposed revenue allocation.

Q. What is the Company's position regarding revenue recovery through the customer charge in this case.

A. Columbia's rate design proposal in this case is designed to recover Columbia's total cost of service. In designing its proposed rates, Columbia pursued three objectives to establish the amount of revenue to be recovered through the customer charge. First, Columbia analyzed the percent of revenue recovery by the customer charge, as compared to base rate revenue recovery as a whole. Columbia's goal was to align the percentage of customer charge recovery to total base rate recovery. Second, Columbia compared the currently approved customer charge to the Minimum System Customer Charge Study (Exhibit 111, Schedule 1, Pages 14 through 18) in the case, with the goal of showing progress toward, at a minimum, a customer charge that would recover the cost of a minimum system. Third, any increase in the proposed customer charge must be gradual, so as to avoid rate shock.

Q. On page 23, lines 6 and 7 of his Direct Testimony, Witness Cline states that the customer charges for the SGS1, SGS2, and SDS/LGSS rate classes are too high. Do you agree with this statement?

A. No. As stated by Witness Notestone in his Direct Testimony, the Company believes a customer component of mains should be included in the minimum system charge study[2], and the Company's current and proposed customer charges are well below the minimum system charges reflected in Exhibit 111, Schedule 1, Page 16, Line 41.

Q. Mr. Cline presents a table on page 24 of his testimony reflecting the customer charges from the Company's minimum system charge study, the Company's proposed customer charges, I&E's proposed customers charges and the difference between the Company's and I&E's customer charges. Do you have any concerns about this table?

A. Yes. The last two columns of the table were switched for the SGSS1/SCD1/SGDS1, SGSS2/SCD2/SGDS2 and SDS/LGSS rate classes. Witness Cline corrected this error in response to Columbia to I&E-4-001, a copy of which is provided as Attachment MJB-2R to my Rebuttal Testimony

Q. Has Witness Cline proposed a method for scaling back rates?

A. Yes. Witness Cline addresses scaling back rates on pages 24 and 25 of his Direct Testimony. He recommends that all customer charges and usage rates that have been proposed an increase be scaled back proportionately based upon the allocated cost of service study that is ultimately approved by the Commission.

Q. Is Columbia opposed to this recommendation?

A. No. The Company will utilize the approved allocated cost of service study to scale back proportionally all revenue requirements for revenue and rate design

[2]Columbia Statement No. 11, Direct Testimony of Chad Notestone, pages 18 and 19.

purposes. However, Columbia proposes to use its proposed revenue allocation and rate design to proportionally scale back all revenue requirements.

II. Response to OCA Witness Jerome D. Mierzwa

Q. What topics in Witness Mierzwa's Direct Testimony does this testimony address?

A. This testimony addresses Witness Mierzwa's Direct Testimony concerning Columbia's proposed revenue allocation, revenue scale back method, residential customer charge, WNA and RNA.

Q. Do you agree with the principles of a sound revenue allocation as presented by Witness Mierzwa beginning on line 10 of page 34 of his Direct Testimony?

A. Yes.

Q. Does Columbia's proposed revenue allocation abide by the principles listed by Witness Mierzwa on page 10 of his Direct Testimony?

A. Yes. Columbia's revenue allocation:

- Utilizes a class cost-of-service study as a guide;
- Provides stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to ratepayers or the utility (gradualism);
- Yields the total revenue requirement;

- Provides for simplicity, certainty, convenience of payment, understandability, public acceptability and feasibility of application; and
- Reflects fairness in the apportionment of the total cost of service among the various classes.

Q. Does the Company agree with Mr. Mierzwa's proposed revenue allocation?

A. No. Mr. Mierzwa's proposed revenue allocation utilizes the OCA's Peak and Average study as the basis of his revenue allocation. As I state on pages 12 through 13 of this testimony, the Company believes that the Average Study, with its equal weighting of the Peak & Average and Customer/Demand Studies, provides the appropriate guide in revenue allocation.

Q. Do you agree with Witness Mierzwa that a scale back method should be used in the event that Columbia's authorized increase is less than the requested increase?

A. Yes. On page 36, lines 9 and 10 of his Direct Testimony, Witness Mierzwa states, "....In the event that CPA's authorized increase is less than its requested increase, I recommend a proportionate scale-back of the increase for each rate class." Columbia's supports a proportional scale back of the Company's proposed revenue allocation if the increase authorized by the Commission is less than the Company's requested increase.

Q. On Page 38 of Mr. Mierzwa' testimony, he compares customer charges

for other natural gas companies in Pennsylvania to Columbia's, and notes that Columbia's current customer charge is already the highest. Do you have any comments?

A. Yes. Differences in rate structures can distort the comparison when looking at just one component in isolation. Mr. Mierzwa correctly notes that Columbia's current customer charge is the highest among regulated natural gas companies in Pennsylvania. However, that fact alone does not indicate how customers are impacted at a non-weather sensitive ("base load") level, where all residential customers are generally consuming the same minimum amount per month.

Q. What are some differences that skew a comparison of the customer charges in isolation?

A. Columbia's residential base rates include a customer charge and a single volumetric rate for all gas consumed. National Fuel Gas Distribution Corporation, for example, has a multiple declining block rate, resulting in recovering more fixed costs in a higher first rate block, which is effectively a minimum monthly charge for base load.

Instead of only looking at the customer charge, a more reasonable comparison of the impact on customers would be to include a customer's base load usage along with the customer charge. This comparison would reflect the impact on customers when the usage is generally at a minimum level. This minimum base load level should thus be the same for all customers each month.

Q. Can you provide a simple example to illustrate the impact of this rate design difference?

A. Table MJB-3R below illustrates how a comparison of only the customer charge can be misleading in terms of cost recovery and impact on the customer. The table below shows the cost of 1 Mcf of base load. Even though the customer charge is higher with Company B, a customer will pay more at 1 Mcf under Company A. The cost for a customer buying gas from Company A is $13.90 ($11.00 plus 1 Mcf at $2.90), compared to a cost of $13.75 ($12.00 plus 1 Mcf at $1.75) for a customer under Company B.

TABLE MJB-3R

	Company A	Company B
Customer Charge	$11.00	$12.00
Volumetic rate per Mcf:		
First block – first 5 Mcf	$2.90	$1.75
Second block – next 20 Mcf	$0.00	N/A
Third block – above 25 Mcf	$0.00	N/A
Cost of 1 Mcf of base load	$13.90	$13.75

Q. What is your response to Mr. Mierzwa's statement that a high fixed monthly customer charge is inconsistent with the Commission's general goal of fostering energy conservation[3]?

A. Mr. Mierzwa's statement refers to the theory that any increase in the system charge reduces the increase to the volumetric charge to the customer which, in turn, reduces the savings incentive to conserve energy. However, Columbia is recommending a

[3] See Direct Testimony of Witness Mierzwa, page 38.

monthly customer charge increase of $6.25, which would make up 6.0 percent of the total monthly bill, in addition to an increase in the volumetric rate. At proposed rates, the proposed customer charge of $23.00 charge represents approximately 21.9 percent of the total monthly bill[4]. It is not reasonable to assume that a customer would make a decision not to invest in conservation when approximately three quarters of the total monthly bill is volumetrically driven.

Q. Do you have any observations on the impact to customers' consumption as it pertains to NiSource's experience in increasing the recovery of fixed costs through higher customer charges?

A. Yes. As I stated previously, Columbia is proposing to increase volumetric rates in this case. Thus, the proposed rate design will charge more for greater residential usage. Also, a large portion of a customer's bill is for recovery of gas costs. Gas costs are recovered on a volumetric basis and therefore reductions in usage will produce savings from conservation.

For example, Columbia Gas of Ohio ("COH") implemented a straight fixed variable ("SFV") rate design for its Small General Service ("SGS") rate class in December 2009. In a SFV rate design, 100 percent of base rate recovery is collected through the customer charge. Of COH's residential customers, approximately 99 percent are served by the SGS rate. COH's average SGS, weather normalized, annual use per customer in 2010 (last full year before SFV) was 86.6

[4] Exhibit 111, Schedule 6, page 1 – typical residential customer who uses 70 therms per month.

Mcf/year. COH's average SGS, weather normalized, annual usage per customer for the 12 months ending July 2020 is 81.4 Mcf/year.

If Mr. Mierzwa's assertions apply, one would expect that a move to 100 percent recovery of base revenue through the customer charge, would cause COH's average annual normalized SGS consumption to increase. Based on actual observations using actual weather normalized residential usage per customer, there is no indication that a small increase in the percentage of fixed costs recover through the customer charge will cause an increase in customer consumption.

Q. Please reiterate the Company's justification for proposing a customer charge of $23.00.

A. The Company recognizes the need to gradually increase fixed charges and strike a balance between gradualism and moving towards the cost to serve residential customers. Columbia also realizes that fixed cost studies rely on various methods and produce a range of results. However, in the spirit of gradualism, the Company's proposed residential customer charge of $23.00 is lower than the results produced by the customer cost studies presented by Witness Notestone.

Q. Have any other parties expressed support for the customer charge as proposed by Columbia?

A. Yes. On page 23, line 9 through page 24, line 3 of I&E Statement No. 3, Witness Cline states the following:

I am also not recommending an adjustment to the residential customer charge because it is consistent with the customer cost analysis.

Q. Please address the OCA's concern with removing the 3 percent deadband from the WNA tariff.

A. On line 20, page 39 of Witness Mierzwa's Direct Testimony, he states, "It is unreasonable to assume that weather and natural gas usage is abnormal if a particular day is only a few HDDs warmer or colder than normal. If the deadband is eliminated, the WNA would be applied if actual weather was only one HDD colder or warmer than normal." This is a true statement, but as I explain earlier in my Rebuttal Testimony, under the current 3 percent deadband scenario, the WNA would also not be applied if weather was 2.5 percent colder or warmer than normal. As shown on Table MJB-3R, at 2.5% colder than normal, a typical residential customer could be charged more than an additional $8 for distribution service due to the 3% deadband. The Company supports removing the deadband and billing less to residential customers, when weather is colder than normal. Additionally, as noted in my response to Witness Cline, the WNA is not an "extreme weather fix" only. By design, the WNA calculation includes every daily temperature variation within a billing month, and not just "extreme days." The 3 percent deadband applies to the total for the billing month, so "extreme days" could be offset by small variances throughout the month.

Q. Mr. Mierzwa, beginning on page 40, line 14 and through Page 41 line 13 of his Direct Testimony, addresses the alternative ratemaking

proceeding, Docket No. M-2015-2518883, initiated by the Commission. Specifically, he mentions 14 factors identified in its Statement of Policy. Has the Company, either directly or indirectly, addressed any of the factors identified in the Statement of Policy?

A. Yes. Please refer to my Direct Testimony, starting on page 20 for a full description of the Company's proposed RNA, which indirectly addressed some of factors relevant to the RNA mechanism.

Q. Please identify the factors which are relevant to the Company's proposed RNA mechanism, and explain the impact to the rates of each customer class.

A. First, it is important to note that the Company is only proposing an RNA mechanism for the non-CAP residential customer class, therefore, there is no impact to the Company's proposed rates for any other rate class. Also, the RNA provides for the establishment of benchmark distribution revenue levels for the non-CAP residential customer class, which the Company would compare to actual non-gas distribution billed revenues for two separate six-month periods[5]. Since the adjustment to the non-CAP residential customer's bill will take place at a future point in time, the Company cannot quantify the impact, if any, to the proposed non-CAP residential rates. Please see below for the factors relevant to the RNA:

[5] Columbia Statement No. 3, Direct Testimony of Melissa J. Bell, page 21, lines 5 through 13.

- **Factor 1 –** How the Ratemaking Mechanism and Rate Design align revenues with cost causation principles as to both fixed and variable costs – The RNA establishes a benchmark distribution revenue based upon approved costs in this proceeding, which will allow the Company to collect the non-CAP residential revenue requirement;
- **Factor 5 –** How the Ratemaking Mechanism and Rate Design limit or eliminate disincentives for the promotion of efficiency programs – Because the link between level of throughput and base revenue recoveries is broken, reduced throughput will not lead to revenue and earnings erosion due to under-recovery (see Factor 1) of these costs and aligns the Company's and its customers interests as it pertains energy efficiency and conservation initiatives.
- **Factor 6 –** How the Ratemaking Mechanism and Rate Design impact customer incentives to employ efficiency measures and distributed energy resources - See Factor 5;
- **Factor 9 -** How weather impacts utility revenue under the Ratemaking Mechanism and Rate Design – The RNA, as proposed will only capture differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments;
- **Factor 12 –** Whether the alternative Ratemaking mechanism and Rate Design Include appropriate consumer protections – 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. As stated on page 26 of my Direct Testimony, lines 1 through 4, the Company 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.

Q. On page 41 of his Direct Testimony, Witness Mierzwa recommends that the Commission not approve the Company's RNA proposal. Do you agree with his testimony concerning RNA?

A. I do not agree with Witness Mierzwa's reasons for recommending that the RNA not be approved. On page 41, lines 25 and 26, he states, "The proposed Rider RNA could increase earnings beyond those that the Company would ordinarily be entitled to." On the next page of his testimony, Witness Mierzwa states that "a new customer is likely to have purchased a more energy efficient gas appliance than an average customer, and would have lower usage...." However, he fails to mention other possibilities, such as the new customer purchases a larger than average home or installs more gas appliances compared to the average residential customer. This is precisely why the RNA benchmark uses an average customer as its basis. New customers could have consumption levels above or below the average usage amount. Furthermore, the Company's new customer projections assume average usage, which is consistent with the Company's RNA benchmark approach.

Q. Witness Mierzwa also states that Rider RNA unreasonably applies to customers with constant usage. Why is this argument flawed?

A. The cost to serve a residential customer is relatively static despite usage differences among residential customers. Because the cost to serve residential customers does not vary with usage, it is reasonable to apply the RNA to all residential customers, regardless of usage.

Q. Beginning on line 1 of page 43 of his Direct Testimony, Witness Mierzwa presents a "take-or-pay" argument to defend OCA's position concerning RNA. Is this argument applicable to gas distribution service provided to residential customers?

A. No. A "take-or-pay" argument may be applicable to the purchase of a commodity, such as gas. However, the same argument does not make sense for providing distribution service. Columbia must have the same infrastructure in place to serve a residential customer, regardless of consumption.

Q. On page 43 of his Direct Testimony, Witness Mierzwa also claims that Rider RNA could lead to "inappropriate rate adjustments." Does the Company agree with this claim?

A. No. On page 43, lines 15 through 18, Witness Mierzwa states, "For example, if Residential usage per customer were to fall over time, while SGSS1/SCD1/SGDS1 deliveries increased, CPA'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. Witness Mierzwa's final argument to reject Columbia's proposed RNA considers revenue stability. Please describe his argument.

A. On page 44, lines 6 through 8, Witness Mierzwa states the following, "CPA's current system of rates and charges, which include fixed monthly customer charges, a Purchased Gas Adjustment mechanism, and Rider WNA, and a distribution system improvement charge ("DSIC"), provide for revenue stability...." This statement is not accurate for a few reasons. 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.

III. Response to OCA Witness Roger D. Colton

Q. What is Mr. Colton's position on Columbia's proposed customer charge?

A. On page 58, lines 1 and 2, Mr. Colton recommends no increase to the residential customer charge, as presented by OCA Witness Mierzwa.

Q. Does the Company agree with this proposal?

A. No. As already stated in response to Mr. Mierzwa, the Company recognizes the need to gradually increase fixed charges and strike a balance between gradualism and moving towards the cost to serve residential customers.

Q. What conclusions has Mr. Colton expressed on the impact to low income customers specifically because Columbia is proposing to increase the current customer charge from $16.75 to $23.00 in this case?

A. Simply stated, Mr. Colton concludes that low income customers are customers that use less than the average residential customer and therefore they will experience a greater increase in their gas bills than the average residential customer if the Company increases its customer charge.

Q. Mr. Colton states on page 77 of his direct testimony that "The proposed $6.25 increase in the Company's fixed monthly customer charge imposes disproportionately high rate increases on low-use customers." Is this true?

A. The short answer is, on average, no. As Mr. Colton points out, not all low-income customers are low-use[6]. Although there are low income customers who reside in small multifamily units, there are also low income customers who live in large old poorly insulated homes with old less efficient furnaces that use above the average residential customer consumption.

The simple fact is, customers that consume more gas than the average will benefit with a higher customer charge and customers that consume less gas than the average will bear a higher financial burden from a higher customer charge regardless of customer income status.

IV. Response to OSBA Witness Robert D. Knecht

Q. Refer to page 30 of Witness Knecht's Direct Testimony. Does Witness Knecht accurately restate the Company's revenue allocation in Table IEc-5?

A. The column labeled "Columbia Proposal" accurately shows the Company's proposed rate increase. The columns labeled "RDK 50/50 Weighting" and "RDK 75/25 Weighting" reflects Witness Knecht's interpretation of costs. I do not agree with Witness Knecht's cost-based increases and I have relied upon the Average Study produced by Witness Notestone.

Q. Do you agree with Witness Knecht's revenue allocation recommendation?

[6] See OCA Statement No. 5, page 65, lines 28 and 29.

A. No. Witness Knecht states on page 2, lines 29 and 32, of his Direct Testimony, "In this testimony, I develop two revenue allocation calculations based on a weighted average of the two Company cost allocation methods and value of service consideration, one based on the Company's 50/50 proposed costing method, and one based on a 75/25 weighting of the P&A and CD methods." In both proposed revenue allocations, Mr. Knecht assigns a revenue increase to the Company's flex customers. Columbia witness Mr. Tubbs, in Columbia Statement No. 1-R, explains why the Company cannot obtain increased revenues from flex customers.

Q. Does Witness Knecht comment on the Company's proposed customer charges for the SGS/SGDS customer classes?

A. Yes. On page 32, line 28 through page 33, line 1 of Witness Knecht's Direct Testimony, he states, "…I believe that the Company's proposals to modestly increase the SGS1 customer charge to $30 and to increase the SGS2 customer charge at $48[7] are cost-justified at the full revenue requirement. If the Company's overall increase is scaled back, the increase in the customer charge for SGS1 should similarly be scaled back. …A similar adjustment should apply to the SGS2 customer charge."

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[7] The Company's proposed customer charge for the SGS2 rate class is $60.00 and the current is $48.00. It is the Company assumption that Mr. Knecht meant to state that the Company's proposed customer charge for the SGS2 rate class is cost justified at the full revenue requirement and is supported by his cost study.

Q. Does the Company agree with Witness Knecht's concerning the scale back of the SGS1 and SGS2 customer charge proposal in the event that the overall increase is scaled back?

A. Yes.

V. Response to CAUSE-PA Witness Mitchell Miller

Q. Refer to page 6, line 11 and lines 18 through 19 of Witness Miller's Direct Testimony. Do you agree that recovery of costs through a fixed charge and Rider RNA undermines efforts by residential consumers to reduce bills through energy efficiency and conservation efforts?

A. I do not agree with Witness Miller's statements concerning fixed charges and RNA. Refer to Exhibit MJB-1R and the associated explanation beginning on page 9 of this testimony. Exhibit MJB-1R demonstrates that the Company's proposed customer charge of $23.00 does not "undermine energy efficiency efforts." This exhibit also shows how the proposed Revenue Normalization Adjustment would reflect what normally happens in the rate case process, when customers implement conservation measures. If residential usage is reduced, then in the Company's next rate case, fixed costs are spread over lower volumes and rates for all residential customers increase. Additionally, Columbia is proposing an increase to the volumetric rate. In addition, gas commodity costs provide customers with a reason to conserve.

Q. Witness Miller repeats some of his RNA arguments on pages 36 and 37 of his Direct Testimony. What is he stating on these pages and do you agree?

A. Witness Miller states "...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." Witness Miller is not accurately stating how the RNA will function. Benchmark revenues are set on a revenue per customer basis. However, rates are designed in the traditional manner with a customer charge and a volumetric charge. The Company's rate design proposal does not significantly impact the ratio of fixed to volumetric charges for residential customers. Therefore, a residential customer's incentive to conserve should not be impacted by Columbia's rate design.

Q. Refer to pages 21 and 22 of Witness Miller's Direct Testimony, where he addresses whether CAP customers are shielded from Columbia's rate increase. Do you agree that some CAP customers will eventually experience bill increases, when rates are increased?

A. I acknowledge that some CAP customers' bills will likely increase subsequent to the implementation of new base rates. However, the CAP customers that have an increase will experience an increase that is no more than half of the full impact of any rate increase. Moreover, as Columbia's Witness Davis explains, if the CAP customer's bill becomes unaffordable, the customer's payment plan can be revised.

Q. Please explain why CAP customers' bills are held constant as part of the rate design process.

A. Consistent with past practice, Columbia held CAP customers' bills constant for the purpose of rate design for a few reasons. First, it is not practical to factor in each CAP customer's updated payment, as part of rate design, and the mix of CAP payment plans changes over time. Additionally, the mix of customers who qualify for CAP varies from year to year. Finally, in order to bill the full allowed revenue requirement to residential customers, the revenue calculation first increases rates to non-CAP and CAP customers the same, and then revenues above a CAP customer's payment are charged to non-CAP customers through Rider USP. This has no actual effect on billing, as the actual, reconciled, Rider USP charges will reflect the actual CAP shortfall.

VI. Response to CAAP Witness Susan A. Moore

Q. Does Witness Moore oppose Columbia's residential customer charge increase?

A. Yes. Ms. Moore, on page 4, lines 1 and 2 of her testimony, states that a customer's motive to conserve and save money would be negatively impacted by the Company's proposed fixed charge. The Company has addressed this in response to OCA Witness Mierzwa and CAUSE Witness Mitchell.

Q. Does Witness Moore support the Company's RNA proposal?

A. No. On page 4 beginning on line 9 through page 5 line 11 concerning Witness Moore's opposition to Columbia's RNA proposal, she states that the RNA, "will have a negative impact on a low income customers' ability and motive to conserve." Witness Moore goes on and states, "Additionally, because of the "lag-time" in the adjustment to rates a customer would not see the connection between reducing consumption and a reduced bill."

Q. Please address Witness Moore's concerns that the Company's RNA proposal will have a negative impact on a low-income customers' ability to conserve.

A. Refer to Exhibit MJB-1R for a demonstration of how a residential customer can experience savings over time due to implementing conservation measures, such as replacing their old furnace and adding insulation to their attic or walls. Exhibit MJB-1R is described in this Rebuttal Testimony in response to Witness Cline. The same response applies here. Additionally, no witness presented any evidence to prove that residential customers stop conserving if the customer charge is increased. It is unlikely that customer will abandon conservation habits due to a higher customer charge, especially when gas costs and volumetric rates still provide ample incentive to conserve.

Q. Do you agree with Witness Moore's second concern that because of the "lag-time" in the RNA adjustment customers would not see the connection between reducing consumption and a reduced bill?

A. No. Witness Moore's statement is flawed because it assumes that residential customers will not experience immediate savings on their bills from Columbia as a result of implementing conservation measures. However, this is simply not true. Customers with reduced usage will experience lower distribution charges and lower gas commodity charges in the months that the lower usage occurs.

Q. Describe the timing and method for applying the RNA charge.

A. The timing of Columbia's proposed Rider RNA is explained beginning on page 21, line 16 through page 22, line 33 of my Direct Testimony, Columbia Statement No. 3 in this case, where I state, "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 2021 billing cycles and ending with March 2022 billing cycles would be applied to residential customers' bills for the period beginning with October 2022 billing cycles and ending with March 2023 billing cycles." Therefore, customers with lower usage will experience savings in a timely way.

Q. In future years, will residential customers continue to experience savings as a result of implementing conservation measures even with Columbia's Rider RNA proposal?

A. Yes. Please refer to Exhibit MJB-1R for an example of how a typical residential customer could experience savings in future periods with Columbia's proposed

Rider RNA. Exhibit MJB-1R is fully explained beginning on page 10 of this testimony in response to Witness Cline. The same response applies here.

VII. Response to CII Witness Frank Plank

Q. On page 9 of his testimony, Mr. Plank recommends that the Commission, if it allows Columbia to increase rates at this time, limit any rate increase to the LDS rate class. What is the Company's response?

A. In response to Mr. Plank's recommendation, I observe that the class as a whole provides less than system average returns in two of Mr. Notestone's three ACOS studies. In this case, the increase to the class is within the amount suggested by the average cost of service study and principles of gradualism at a 27.2 percent increase, which is 3.22 percent more than the proposed base rate increase of 23.99 percent[8]. Even with a base revenue increase of 27.2 percent increase, the LDS rate class is still under-performing when compared to the other rate classes, excluding Flex. As I stated on page 35 of my Direct Testimony, I limited the increase to this rate class in order to strike a balance between competing rate design goals of fairness and gradualism. As such, I do not think it is necessary to reallocate a portion of the increase to other customer classes in this instance.

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[8] Exhibit 103, Schedule 8, page 1, lines 36 and 37.

VIII. Columbia's Response to the Commission directive in the Order issued on August 20, 2020 in Docket No. R-2020-3018835

Q. Are you responding to the Commission's Order issued on August 20, 2020 concerning Columbia's Petition for Reconsideration of Staff Action filed on June 23, 2020 in Docket R-2020-3018835?

A. Yes. The Commission directed the Parties to address the following issues related to rate recovery: (1) the appropriate amount of rate recovery starting from the end of the Section 1308(d) suspension period, January 23, 2021, until the date the final rates are approved in a final Commission order and take effect in the utility's compliance tariff filing; and (2) the appropriate mechanism for implementing such rate recovery.

Q. Please address the appropriate amount of rate recovery from January 23, 2021 through the date of the final Commission Order and approval of the compliance tariff filing.

A. The rate recovery for this period is not known at this time and is not needed, in advance of billing. Back billing will not change the amount of rate recovery for this period. It will only delay the billing of any incremental revenue due to a Commission-approved rate increase until a customer's bill is issued for the subsequent month. Simply stated, the Company will, for each customer, apply the Commission-approved rates to prior billed usage, and the backbilling amount will be the difference between the amount calculated at new rates and amounts actually billed previously at old rates.

Q. Please address the appropriate mechanism for implementing such rate recovery.

A. Columbia will not need to use a special rate mechanism for implementation. Once new base rates are approved and entered into the billing system, customer specific billing adjustments will be calculated and added to each customer's bill. The individual billing adjustments will be computed using each customer's consumption for the appropriate period. I note this is the process used any time that compliance rates are not approved until sometime after the effective date of new rates in a base rate case.

Q. What will the backbilling amount be?

A. The amount per customer will be customer specific. However, I note that, as shown in Filing Exhibit 111, Schedule 6, page 1, at the Company's proposed rates, a residential customer using 10 therms in a winter month would owe an additional $7.59.

Q. Will Columbia incur incremental IT costs due to the need to back bill rates?

A. Yes. Columbia estimates the incremental costs to be in the range of $85,000 to $160,000.

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	$23.00	$7.3323	$3.4808	[5]+[6]+[7]	Replaced	Insulation	Insulation	[9+10+11]
								Hypothetical Annual Dth Reduction			
								16.2	11.3	16.0	43.5
1	2021	Jan	16.78	$23.00	$123.04	$58.41	$204.46				
2	2021	Feb	16.64	$23.00	$122.00	$57.92	$202.92				
3	2021	Mar	13.86	$23.00	$101.61	$48.24	$172.85				
4	2021	Apr	8.88	$23.00	$65.08	$30.90	$118.98				
5	2021	May	4.09	$23.00	$30.01	$14.25	$67.26				
6	2021	Jun	2.06	$23.00	$15.08	$7.16	$45.25				
7	2021	Jul	1.27	$23.00	$9.34	$4.43	$36.77				
8	2021	Aug	1.18	$23.00	$8.65	$4.11	$35.76				
9	2021	Sep	1.22	$23.00	$8.95	$4.25	$36.19				
10	2021	Oct	2.20	$23.00	$16.15	$7.67	$46.82				
11	2021	Nov	5.51	$23.00	$40.43	$19.19	$82.62				
12	2021	Dec	12.35	$23.00	$90.56	$42.99	$156.55	Conservation Savings			
13	Total	Annual	86.05	$276.00	$630.92	$299.51	$1,206.42	$175.17	$122.19	$173.01	$470.37
14											
15	Scenario A - Hypothetical RNA Rate A =				$0.25	per Dth		$17.46	$18.69	$17.51	$10.64
16	Scenario A - Conservation Savings							$157.71	$103.50	$155.50	$459.73
17											
18	Scenario B - Hypothetical RNA Rate B =				$0.75	per Dth		$52.38	$56.06	$52.53	$31.91
19	Scenario B - Conservation Savings							$122.79	$66.13	$120.48	$438.46

Notes:

*1) Refer to Exhibit No. 10, Schedule No. 2, Page 8 of 8; Witness Bikienga

*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.

Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2020-3018835

Responses of the Bureau of Investigation and Enforcement to Columbia Gas of Pennsylvania, Inc. Interrogatories Set IV
Witness: Ethan Cline

Columbia to I&E-IV-1 Please explain the basis for the negative proposed customer charges presented in the table on page 24 of Witness Cline's direct testimony. Were the Change and I&E Proposed Rate columns inverted?

Response: **Mr. Cline did not propose negative customer charges. The Change and I&E Proposed Rate columns for all classes except the RS, RDS, RCC classes, were inadvertently inverted. A corrected table is below. It should also be noted that the change in the SGSS1, SCD1, SGDS1 classes was listed incorrectly as negative $14.00 in Mr. Cline's Direct Testimony. Mr. Cline is proposing to decrease the customer charge for these classes by $4.00 from the Company's proposed $30.00 to $26.00 as shown below.**

Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Proposed Rate	Change	I&E Proposed Rate
RS, RDS, RCC				
All Usage	$23.05	$23.00	$0.00	$23.00
SGSS1, SCD1, SGDS1				
≤6,440	$25.87	$30.00	($4.00)	$26.00
SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$43.99	$60.00	($15.00)	$45.00
SDS/LGSS				
>64,400 to ≤110,000	$191.02	$290.00	($98.98)	$191.02
>110,000 to ≤540,000	$919.89	$940.00	($20.00)	$920.00

COLUMBIA STATEMENT NO. 4-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

August 26, 2020

Table of Contents

I. <u>Introduction</u>

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. Are you the same Kelley K. Miller that submitted Direct testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to:

- Provide an updated revenue requirement deficiency of $100,366,797 which incorporates all adjustments provided by Columbia Gas of Pennsylvania, Inc. ("Columbia" of "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 by other witnesses;
- Provide the calculated impacts to Labor Expense for Revised GAS-RR-026, Attachment A as explained by witness Nancy Krajovic in her Rebuttal testimony;

- Provided the calculated impacts to Labor Expense for recent changes to NiSource's 2020 Merit Program as explained by witness Kimberly Cartella in her Rebuttal testimony;
- Respond to O&M ratemaking adjustments made by Mr. Zalesky, witness for the Bureau of Investigation and Enforcement ("I&E"), regarding labor annualization and rate case 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. <u>Exhibit KKM-1R, Updated Revenue Requirement</u>

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 $100,366,797 as compared to the Company's originally stated revenue requirement of $100,437,420. 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") Operations & Maintenance ("O&M") Expense on Exhibit 102, Schedule 3, Page 3, Line 18, Columns 7 and 8 (Exhibit KKM-1R, Page 1).

Per Company witness Krajovic, the following O&M Expense adjustments are reflected in the Company's revised revenue requirement:

- Budget Billing Modification Costs ($280,000)
- Labor Expense (Revised GAS-RR-026, Exhibit KKM-3R Column 2) $8,415

2. 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 8.00% to reflect actual long term debt costs for a recent issuance of debt.

Please see witness Krajovic's and witness Moul's rebuttal testimonies for further details concerning the adjustments listed above.

Further, per the testimony of Company witness Cartella, O&M Labor Expense has been adjusted by a decrease of $274,666 (total of $150,246 and $124,420 discussed below) due to changes to the 2020 Merit Increase Program. These changes are reflected in the Company's revised revenue requirement and are addressed below in my testimony.

III. Labor Expense Adjustments

Q. Have you determined the impacts to Labor Expense resulting from Revised GAS-RR-026, Attachment A, presented in the Company's

response to OCA-5-017?

A. Yes, as supported by Company witness Krajovic, and provided as Exhibit NJDK-5R, page 3 of 8, I have confirmed the net impact to the FPFTY to be $8,415. Please see Exhibit KKM-4R, Page 1, Columns 2 and 3 for the breakout between budget adjustments and ratemaking adjustments for both the Future Test Year ("FTY") and the FPFTY.

Q. Are there other items that need to be updated as a result of the response to OCA-5-017?

A. Yes, based upon witness Krajovic's revised GAS-RR-026, I have revised the response to OCA-02-045, provided as CONFIDENTIAL Exhibit KKM-2R attached hereto, which is the supporting workpaper for the labor annualization adjustment. I have also revised Exhibit 104, Schedule 2, Page 1 of 19, provided as Exhibit KKM-3R.

Q. Have you determined the impacts to Labor Expense resulting from the changes to the 2020 Merit Increase Program as supported by Company witness Cartella?

A. Yes. Exhibit KKM-4R, Page 1, Columns 4 through 7 summarizes the resulting impacts to the FTY and FPFTY Labor Expense

Q. Please can you further explain the 2020 and 2021 Merit Program changes supported by Company witness Cartella, and quantify the impacts to the Company's claim?

A. Yes. The 2020 Merit Increase Program changes impact to Labor Expense are twofold.

First, NiSource has elected to forego awarding the annual merit increases for non-union exempt employees in director positions and above in 2020. The Columbia and NCSC employee 2020 merit eliminations for these positions as supported by Company witness Cartella result in a calculated reduction in FPFTY Labor Expense of $150,246 as presented in Column 4 of Exhibit KKM-4R, Page 1. Secondly, modifications to the annual 2020 and 2021 merit processes have been made regarding timing and the 2020 process with regard to percentages of increases, as described in detail in Company witness Cartella's rebuttal testimony. The Company has calculated a reduction in Labor Expense totaling $124,420 resulting from the changes in 2020 merit increases percentage for Columbia and NCSC employees as presented in Column 6 of Exhibit KKM-4R, Page 1. For additional information, see page 2 of Exhibit KKM-4R which provides a breakout of the calculations of merit changes for Columbia employees, and page 3 which provides a breakout of the calculations of merit changes for NCSC employees. The data on these pages are exclusive of Labor Adjustment #1 on page 1 of Exhibit KKM-4R. Note, additional changes regarding the timing of merit increases in 2020 and 2021 have also been made, but have no bearing on annualized labor expense.

Q. Please summarize all impacts to Labor Expense that you have included in Exhibit KKM-1R and KKM-4R.

A. There are three items outlined above that account for changes to Labor Expense:

1. An increase of $8,415 per revised GAS-RR-026, supported by Company witness Krajovic;
2. A decrease of $150,246 resulting from the elimination of the 2020 Merit for employees at the director level and above, and
3. A decrease of $124,420 resulting from the changes in percentage of the 2020 Merit program for other employees, supported by Company witness Cartella.

The total of all three adjustments to Labor expense is a decrease of $266,251 as shown on Row 16, Column 7 of Exhibit KKM-4R.

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, Taxes Other Than Income (related to the Columbia Labor adjustments) and Income Taxes, included in 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.

IV. I&E's Recommended Ratemaking Adjustments

Q. Have you reviewed Witness Zalesky's testimony concerning the Company's ratemaking adjustment for labor annualization?

A. Yes.

Q. Do you agree with his recommendation to disallow the entire as-filed claim of $497,691 for annualizing labor expense?

A. No. The Company has annualized this expense to match the overall claim in the case of annualized revenue, terminal rate base and annualized expenses. Future union wage increases are based on existing union agreements and expected non-union merit increases as described by Company witness Cartella's rebuttal testimony. As annual merit increases have occurred, and are anticipated to occur in the future, an annualization adjustment is applied to the budgeted Labor Expense in order to calculate the expected annual ongoing level of expense in the rate year, i.e. FPFTY.

Additionally, Mr. Zalesky's claim that "a revenue requirement calculated on this basis would recover, dollar-for-dollar, an expense level for labor that will never be reached in the FPFTY" is unfounded. Recovery of costs through base rates are not designed to recover costs dollar-for-dollar as they are not reconciled, as opposed to costs that are recovered in a reconciling tracker mechanism. As such, the annualization of labor expense is appropriate. This ratemaking adjustment is consistent with the Company's historic practice of annualizing test year Labor Expense. Further, I am advised by counsel that the annualization of labor costs to end-of-year conditions was approved by the Commission in the 2018 UGI Electric rate case, as a proper determination of FPFTY expense.

Q. Did the Company update the annualization adjustments for both the FTY and the FPFTY?

A. Yes. Please see CONFIDENTIAL Exhibit KKM-2R for the updated labor annualization workpaper revised per the Company's response to OCA-5-017 (included in witness Krajovic's testimony as Exhibit NJDK-5R). The updated amounts are also available on Exhibit KKM-3R, Column 2. As previously described in my rebuttal testimony, Exhibit KKM-4R, Columns 4 through 7 provide the adjustments resulting from changes in the 2020 Merit Increase Program.

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 no, 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. During recent years, the Company has filed annual rate cases with only a few exceptions, therefore, a 12-month normalization period is appropriate.

V. OCA's Recommended Ratemaking Adjustments

Q. Have you reviewed OCA witness Effron's testimony concerning Rate Case Expense?

A. Yes. Mr. Effron recommends a two year 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 adjustments for Rate Case Expense, it is appropriate to use a 12-month period, not a two-year period. Furthermore, Mr. Effron's calculation of a 24-month normalization period is biased and incorrect. Mr. Effron supports his assertion using the Company's last three previous rate case filings, filed in March of 2015, 2016 and 2018, respectively and concludes the Company has a history of filing rate cases every two years, even though clearly the 2015 and the 2016 Rate Cases were filed in consecutive years.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Statement of Income at Present and Proposed Rates
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.	Description	Reference (1)	TME November 30, 2019 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	401,921,460	2,259,240	404,180,700	2,627,538	406,808,238	144,252	406,952,490	97,576,331	504,528,821
3	Fuel Revenues	Exhibit 3 / 103	168,425,619	(26,878,488)	141,547,131	(2,638,564)	138,908,567	26,409	138,934,976	-	138,934,976
4	Rider USP	Exhibit 3 / 103	30,748,699	(8,996,079)	21,752,620	328,676	22,081,296	(110,682)	21,970,614	4,752,145	26,722,759
5	Gas Procurement Charge	Exhibit 3 / 103	2,396,994	214,093	2,611,087	(95,594)	2,515,493	8,205	2,523,698	(2,153,314)	370,384
6	Merchant Function Charge	Exhibit 3 / 103	1,204,274	(278,696)	925,578	(63,446)	862,132	5,258	867,390	-	867,390
7	Rider CC	Exhibit 3 / 103	45,968	809	46,777	803	47,580	(269)	47,311	-	47,311
8	Pipeline Penalty Refund	Exhibit 3	(1,870,651)	1,870,651	-	-	-	-	-	-	-
9	Total Sales and Transportation Revenue		602,872,363	(31,808,470)	571,063,893	159,413	571,223,306	73,173	571,296,479	100,175,162	671,471,641
10	Off System Sales Revenue	Exhibit 3 / 103	3,589,350	(3,589,350)	-	-	-	-	-	-	-
11	Late Payment Fees	Exhibit 3 / 103	1,080,703	11,742	1,092,445	305	1,092,750	140	1,092,890	191,635	1,284,525
12	Other Operating Revenues (Excl. Transportation)	Exhibit 3 / 103	376,768	3,438	380,205	-	380,205	-	380,205	-	380,205
13	Total Operating Revenues		607,919,184	(35,382,641)	572,536,543	159,718	572,696,261	73,313	572,769,574	100,366,797	673,136,371
							-				
14	Operating Revenue Deductions										
15	Gas Supply Expense	Exhibit 3 / 103	168,425,619	(26,878,488)	141,547,131	(2,638,564)	138,908,567	26,409	138,934,976	-	138,934,976
16	Off System Sales Expense	Exhibit 3 / 103	3,589,350	(3,589,350)	-	-	-	-	-	-	-
17	Gas Used in Company Operations		(379,743)	379,743	-	-	-	-	-	-	-
18	Operating and Maintenance Expense	Exhibit 4 / 104	188,447,880	1,178,920	189,626,800	(2,406,284)	187,220,516	10,507,278	197,727,794	1,139,534	198,867,328
19	Depreciation and Amortization	Exhibit 5 / 105	65,429,359	6,041,289	71,470,648	10,012,085	81,482,733	12,665,989	94,148,722	-	94,148,722
20	Net Salvage Amortized	Exhibit 5 / 105	5,815,758	(1,156,923)	4,658,835	(219,055)	4,439,780	244,287	4,684,067	-	4,684,067
21	Taxes Other Than Income Taxes	Exhibit 6 /106	3,514,764	216,652	3,731,416	(20,862)	3,710,554	114,991	3,825,546	-	3,825,546
22	Total Operating Revenue Deductions		434,842,987	(23,808,157)	411,034,830	4,727,320	415,762,150	23,558,954	439,321,104	1,139,534	440,460,639
23	Operating Income Before Income Taxes		173,076,197	(11,574,483)	161,501,713	(4,567,602)	156,934,112	(23,485,641)	133,448,470	99,227,263	232,675,733
24	Income Taxes	Exhibit 7 / 107	24,860,731	4,995,237	29,855,968	(5,504,941)	24,351,027	(7,824,406)	16,526,621	24,292,365	40,818,986
25	Investment Tax Credit	Exhibit 7 / 107	(299,568)	-	(299,568)	12,456	(287,112)	29,697	(257,415)	-	(257,415)
26	Operating Income		148,515,034	(16,569,720)	131,945,313	924,883	132,870,197	(15,690,932)	117,179,264	74,934,898	192,114,162
27	Rate Base	Exhibit 8 / 108	1,966,199,619	(115,661,862)	1,850,537,758	205,474,499	2,056,012,257	345,414,762	2,401,427,019	-	2,401,427,019
28	% Rate of Return Earned on Rate Base		7.55%		7.13%		6.46%		4.88%		8.00%

R-2020-3018835

Exhibit KKM-1R
Page 2 of 4

Exhibit No. 102
Schedule 3
Page 4 of 6
Witness: K. K. Miller

Columbia Gas of Pennsylvania, Inc.
Calculation of Proforma Interest Expense
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.	Description	Pro Forma (1) $
	FTY Calculation	
1	Rate Base	2,056,012,257
2	Weighted Cost of Short &	
3	Long Term Debt	2.070%
4	Interest Expense	42,559,454
	FPFTY Calculation	
5	Rate Base	2,401,427,019
6	Weighted Cost of Short &	
7	Long Term Debt	2.070%
8	Interest Expense	49,709,539

Columbia Gas of Pennsylvania, Inc.
Rate of Return on Rate Base
Proposed Revenue Requirement
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.	Description	Detail	Amount
			(1)
			$
1	Proforma Rate Base at Present Rates		2,401,427,019
2	Return on Rate Base		8.000%
3	Total Requirement		192,114,162
4	Less: Net Operating Income at Present Rates		117,179,264
5	Net Required Operating Income		74,934,897
6	Revenue Conversion Factor		1.33938660
7	Gross Revenue Requirement		100,366,797
8	Revenue Conversion Factor:		
9	Operating Revenue		1.00000000
10	Plus: Late Payments		0.00191300
11	Less: Uncollectibles		0.01135370
12	Income Before State Taxes		0.99055930
13	State Income Tax Effect Tax Rate		0.04591630
14	Less: State Income Tax		0.04548282
15	Income Before Federal Taxes		0.94507648
16	Less: Federal Tax @ 21%		0.19846606
17	Adjusted Operating Income		0.74661042
18	Revenue Conversion Factor		1.33938660

Exhibit No. 102
Schedule 3
Page 6 of 6
Witness: K. K. Miller

Columbia Gas of Pennsylvania, Inc.
Additional Revenue Requirement Adjustments
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.		Description	Amount (1) $
1		Additional Revenue Requirement	100,175,162
2	Plus:	Late Payments	191,635
3		Total Revenue Requirement	100,366,797
4	Less:	Uncollectible Accounts Expense	
5		Line 3 X Uncollectible Rate	1,139,534
6		Income Before State Income Tax	99,227,263
7		State Income Taxes	
8		Exh 107, Pg 17, Col 3 Less Exh 107, Pg 17, Col 2	4,372,962
9		Income Before Federal Income Tax	94,854,301
10		Federal Income Taxes	
11		Line 9 Times 21%	19,919,403
12		Net Required Operating Income	74,934,898

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Future Test Year TME 12/31/21
Labor Adjustment Summary (Normal Pay Only)

Line No.	Description	Reference	AS FILED Amount (1) $	Revised Per OCA-05-017 Amount (2) $
	FTY Adjustment			
1	FTY Total Labor Adjustment		1,090,167	1,090,167
2	O&M Percentage	Budget System O&M Factor	49.98%	54.91%
3	FTY O&M Labor Annualization Adjustment	Ln 1 x Ln 2	544,916	598,611
4	Lobbying Adjustment		(8,698)	(8,698)
5	FTY O&M Labor Adjustment		536,218	589,913
	FPFTY Adjustment			
6	FPFTY Total Labor Adjustment		996,176	996,176
7	O&M Percentage	Budget System O&M Factor	49.96%	54.87%
8	FPFTY O&M Labor Annualization Adjustment	Ln 6 x Ln 7	497,691	546,602
9	Lobbying Adjustment		(8,959)	(8,959)
10	FPFTY O&M Labor Adjustment		488,732	537,643

Line No.		Labor As Filed (1) $	Labor Adjustment #1: OCA-05-017 Adjustments (2) $	Labor Adjustment #1: OCA-05-017 Labor as Adjusted (3) $	Labor Adjustment #2: Merit Change to 0% For Directors and Above for 2020 Adjustments (4) $	Labor Adjustment #2: Cumulative OCA-05-17 and Merit Elimination for Directors & Above Adjusted (5) $	Labor Adjustment #3: Merit Changes For Other CPA and NCSC Employees for 2020 Adjustments (6) $	Labor Adjustment #3: Cumulative OCA-05-17, Merit Elimination for Directors & Above and Other Employee Merits Adjusted (7) $
	CPA Direct Labor							
1	Normalized HTY Labor	39,142,312	-	39,142,312	-	39,142,312	-	39,142,312
2	Budget Adjustment	(2,145,312)	763,690	(1,381,622)	(14,603)	(1,396,225)	(15,577)	(1,411,802)
3	Annualization Adjustment	536,218	53,695	589,913	(14,603)	575,310	(15,577)	559,733
4	Normalized FTY Labor	37,533,218	817,385	38,350,603	(29,206)	38,321,397	(31,153)	38,290,243
5	Budget Adjustment	1,505,782	(857,881)	647,901	2,078	649,979	2,216	652,195
6	Annualization Adjustment	488,732	48,911	537,643	(2,932)	534,711	(3,128)	531,583
7	Normalized FPFTY Labor	39,527,732	8,415	39,536,147	(30,061)	39,506,086	(32,064)	39,474,022
	NCS Labor Billed to CPA							
8	Normalized HTY Labor	20,569,337	-	20,569,337	-	20,569,337	-	20,569,337
9	Budget Adjustment	1,333,044	-	1,333,044	(58,342)	1,274,701	(44,833)	1,229,869
10	Annualization Adjustment	327,753	-	327,753	(58,342)	269,411	(44,833)	224,578
11	Normalized FTY Labor	22,230,134	-	22,230,134	(116,685)	22,113,449	(89,665)	22,023,783
12	Budget Adjustment	918,324	-	918,324	8,265	926,589	6,351	932,940
13	Annualization Adjustment	289,336	-	289,336	(11,766)	277,570	(9,041)	268,529
14	Normalized FPFTY Labor	23,437,793	-	23,437,793	(120,185)	23,317,608	(92,355)	23,225,252
15	**Total FTY**	**Line 4 + Line 11**	**817,385**		**(145,891)**		**(120,819)**	**550,675**
16	**Total FPFTY**	**Line 7 + Line 14**	**8,415**		**(150,246)**		**(124,420)**	**(266,251)**

		CPA Employees					
Line Number		**Annual Assumed In Case at 3%**		**Annual Revised Amount**		**FTY Decrease**	**FPFTY Decrease**
		(1)		**(2)**		**(3)=(2)-(1)**	**(4)=(3*3%)+(3)**
1	Directors and Above Merit Increase	53,189.57	1/	-		(53,189.57)	(54,785.25)
2	O&M Percentage					54.91%	54.87%
3	Net Change to O&M Directors and Above					(29,206.39)	(30,060.67)
4							
5	Other Merit Changes	463,028.00	2/	406,293.00	2/	(56,735.00)	(58,437.05)
6	O&M Percentage					54.91%	54.87%
7	Net Change to O&M Other Merit Changes					(31,153.19)	(32,064.41)
8							
9	**Total Change for CPA Employees**					**(60,360.00)**	**(62,125.00)**

1/ Represents 3% of annualized wages for all employees at Director and above at November 30, 2019.
2/ Per Kimberly Cartella, Director of Compensation.

Line Number		NCSC Employees: Annual Assumed In Case at 3% (1)		Annual Revised Amount (2)		FTY Decrease (3)=(2)-(1)	FPFTY Decrease (4)=(3*3%)+(3)
1	Directors and Above Merit Increase	996,563.83	1/	-		(996,563.83)	(1,026,460.75)
2	CPA Percentage					14.96%	14.96%
3	Allocation to CPA					(149,063.03)	(153,534.92)
4	O&M Percentage					78.28%	78.28%
5	Net Change to O&M Directors and Above					(116,684.90)	(120,185.45)
6							
7	Other Merit Changes	3,281,999.87	2/	2,516,199.90	2/	(765,799.97)	(788,773.97)
8	CPA Percentage					14.96%	14.96%
9	Allocation to CPA					(114,546.06)	(117,982.44)
10	O&M Percentage					78.28%	78.28%
11	Net Change to O&M Other Merit Changes					(89,665.40)	(92,355.36)
12							
13	**Total Change for NCSC Employees**					**(206,350.00)**	**(212,541.00)**

1/ Represents 3% of annualized wages for all employees at Director and above at November 30, 2019.
2/ Per Kimberly Cartella, Director of Compensation.

COLUMBIA STATEMENT NO. 4-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

August 26, 2020

Table of Contents

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. Are you the same Kelley K. Miller that submitted Direct testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to:

- Provide an updated revenue requirement deficiency of $100,366,797 which incorporates all adjustments provided by Columbia Gas of Pennsylvania, Inc. ("Columbia" of "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 by other witnesses;
- Provide the calculated impacts to Labor Expense for Revised GAS-RR-026, Attachment A as explained by witness Nancy Krajovic in her Rebuttal testimony;

- Provided the calculated impacts to Labor Expense for recent changes to NiSource's 2020 Merit Program as explained by witness Kimberly Cartella in her Rebuttal testimony;
- Respond to O&M ratemaking adjustments made by Mr. Zalesky, witness for the Bureau of Investigation and Enforcement ("I&E"), regarding labor annualization and rate case 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 $100,366,797 as compared to the Company's originally stated revenue requirement of $100,437,420. 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") Operations & Maintenance ("O&M") Expense on Exhibit 102, Schedule 3, Page 3, Line 18, Columns 7 and 8 (Exhibit KKM-1R, Page 1).

Per Company witness Krajovic, the following O&M Expense adjustments are reflected in the Company's revised revenue requirement:

- Budget Billing Modification Costs ($280,000)
- Labor Expense (Revised GAS-RR-026, Exhibit KKM-3R Column 2) $8,415

2. 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 8.00% to reflect actual long term debt costs for a recent issuance of debt.

Please see witness Krajovic's and witness Moul's rebuttal testimonies for further details concerning the adjustments listed above.

Further, per the testimony of Company witness Cartella, O&M Labor Expense has been adjusted by a decrease of $274,666 (total of $150,246 and $124,420 discussed below) due to changes to the 2020 Merit Increase Program. These changes are reflected in the Company's revised revenue requirement and are addressed below in my testimony.

III. Labor Expense Adjustments

Q. Have you determined the impacts to Labor Expense resulting from Revised GAS-RR-026, Attachment A, presented in the Company's

response to OCA-5-017?

A. Yes, as supported by Company witness Krajovic, and provided as Exhibit NJDK-5R, page 3 of 8, I have confirmed the net impact to the FPFTY to be $8,415. Please see Exhibit KKM-4R, Page 1, Columns 2 and 3 for the breakout between budget adjustments and ratemaking adjustments for both the Future Test Year ("FTY") and the FPFTY.

Q. Are there other items that need to be updated as a result of the response to OCA-5-017?

A. Yes, based upon witness Krajovic's revised GAS-RR-026, I have revised the response to OCA-02-045, provided as CONFIDENTIAL Exhibit KKM-2R attached hereto, which is the supporting workpaper for the labor annualization adjustment. I have also revised Exhibit 104, Schedule 2, Page 1 of 19, provided as Exhibit KKM-3R.

Q. Have you determined the impacts to Labor Expense resulting from the changes to the 2020 Merit Increase Program as supported by Company witness Cartella?

A. Yes. Exhibit KKM-4R, Page 1, Columns 4 through 7 summarizes the resulting impacts to the FTY and FPFTY Labor Expense

Q. Please can you further explain the 2020 and 2021 Merit Program changes supported by Company witness Cartella, and quantify the impacts to the Company's claim?

A. Yes. The 2020 Merit Increase Program changes impact to Labor Expense are twofold.

First, NiSource has elected to forego awarding the annual merit increases for non-union exempt employees in director positions and above in 2020. The Columbia and NCSC employee 2020 merit eliminations for these positions as supported by Company witness Cartella result in a calculated reduction in FPFTY Labor Expense of $150,246 as presented in Column 4 of Exhibit KKM-4R, Page 1. Secondly, modifications to the annual 2020 and 2021 merit processes have been made regarding timing and the 2020 process with regard to percentages of increases, as described in detail in Company witness Cartella's rebuttal testimony. The Company has calculated a reduction in Labor Expense totaling $124,420 resulting from the changes in 2020 merit increases percentage for Columbia and NCSC employees as presented in Column 6 of Exhibit KKM-4R, Page 1. For additional information, see page 2 of Exhibit KKM-4R which provides a breakout of the calculations of merit changes for Columbia employees, and page 3 which provides a breakout of the calculations of merit changes for NCSC employees. The data on these pages are exclusive of Labor Adjustment #1 on page 1 of Exhibit KKM-4R. Note, additional changes regarding the timing of merit increases in 2020 and 2021 have also been made, but have no bearing on annualized labor expense.

Q. Please summarize all impacts to Labor Expense that you have included in Exhibit KKM-1R and KKM-4R.

A. There are three items outlined above that account for changes to Labor Expense:

1. An increase of $8,415 per revised GAS-RR-026, supported by Company witness Krajovic;
2. A decrease of $150,246 resulting from the elimination of the 2020 Merit for employees at the director level and above, and
3. A decrease of $124,420 resulting from the changes in percentage of the 2020 Merit program for other employees, supported by Company witness Cartella.

The total of all three adjustments to Labor expense is a decrease of $266,251 as shown on Row 16, Column 7 of Exhibit KKM-4R.

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, Taxes Other Than Income (related to the Columbia Labor adjustments) and Income Taxes, included in 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.

IV. I&E's Recommended Ratemaking Adjustments

Q. Have you reviewed Witness Zalesky's testimony concerning the Company's ratemaking adjustment for labor annualization?

A. Yes.

Q. Do you agree with his recommendation to disallow the entire as-filed claim of $497,691 for annualizing labor expense?

A. No. The Company has annualized this expense to match the overall claim in the case of annualized revenue, terminal rate base and annualized expenses. Future union wage increases are based on existing union agreements and expected non-union merit increases as described by Company witness Cartella's rebuttal testimony. As annual merit increases have occurred, and are anticipated to occur in the future, an annualization adjustment is applied to the budgeted Labor Expense in order to calculate the expected annual ongoing level of expense in the rate year, i.e. FPFTY.

Additionally, Mr. Zalesky's claim that "a revenue requirement calculated on this basis would recover, dollar-for-dollar, an expense level for labor that will never be reached in the FPFTY" is unfounded. Recovery of costs through base rates are not designed to recover costs dollar-for-dollar as they are not reconciled, as opposed to costs that are recovered in a reconciling tracker mechanism. As such, the annualization of labor expense is appropriate. This ratemaking adjustment is consistent with the Company's historic practice of annualizing test year Labor Expense. Further, I am advised by counsel that the annualization of labor costs to end-of-year conditions was approved by the Commission in the 2018 UGI Electric rate case, as a proper determination of FPFTY expense.

Q. Did the Company update the annualization adjustments for both the FTY and the FPFTY?

A. Yes. Please see CONFIDENTIAL Exhibit KKM-2R for the updated labor annualization workpaper revised per the Company's response to OCA-5-017 (included in witness Krajovic's testimony as Exhibit NJDK-5R). The updated amounts are also available on Exhibit KKM-3R, Column 2. As previously described in my rebuttal testimony, Exhibit KKM-4R, Columns 4 through 7 provide the adjustments resulting from changes in the 2020 Merit Increase Program.

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 no, 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. During recent years, the Company has filed annual rate cases with only a few exceptions, therefore, a 12-month normalization period is appropriate.

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 a two year 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 adjustments for Rate Case Expense, it is appropriate to use a 12-month period, not a two-year period. Furthermore, Mr. Effron's calculation of a 24-month normalization period is biased and incorrect. Mr. Effron supports his assertion using the Company's last three previous rate case filings, filed in March of 2015, 2016 and 2018, respectively and concludes the Company has a history of filing rate cases every two years, even though clearly the 2015 and the 2016 Rate Cases were filed in consecutive years.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Statement of Income at Present and Proposed Rates
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.	Description	Reference (1)	TME November 30, 2019 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	401,921,460	2,259,240	404,180,700	2,627,538	406,808,238	144,252	406,952,490	97,576,331	504,528,821
3	Fuel Revenues	Exhibit 3 / 103	168,425,619	(26,878,488)	141,547,131	(2,638,564)	138,908,567	26,409	138,934,976	-	138,934,976
4	Rider USP	Exhibit 3 / 103	30,748,699	(8,996,079)	21,752,620	328,676	22,081,296	(110,682)	21,970,614	4,752,145	26,722,759
5	Gas Procurement Charge	Exhibit 3 / 103	2,396,994	214,093	2,611,087	(95,594)	2,515,493	8,205	2,523,698	(2,153,314)	370,384
6	Merchant Function Charge	Exhibit 3 / 103	1,204,274	(278,696)	925,578	(63,446)	862,132	5,258	867,390	-	867,390
7	Rider CC	Exhibit 3 / 103	45,968	809	46,777	803	47,580	(269)	47,311	-	47,311
8	Pipeline Penalty Refund	Exhibit 3	(1,870,651)	1,870,651	-	-	-	-	-	-	-
9	Total Sales and Transportation Revenue		602,872,363	(31,808,470)	571,063,893	159,413	571,223,306	73,173	571,296,479	100,175,162	671,471,641
10	Off System Sales Revenue	Exhibit 3 / 103	3,589,350	(3,589,350)	-	-	-	-	-	-	-
11	Late Payment Fees	Exhibit 3 / 103	1,080,703	11,742	1,092,445	305	1,092,750	140	1,092,890	191,635	1,284,525
12	Other Operating Revenues (Excl. Transportation)	Exhibit 3 / 103	376,768	3,438	380,205	-	380,205	-	380,205	-	380,205
13	Total Operating Revenues		607,919,184	(35,382,641)	572,536,543	159,718	572,696,261	73,313	572,769,574	**100,366,797**	673,136,371
							-				
14	Operating Revenue Deductions										
15	Gas Supply Expense	Exhibit 3 / 103	168,425,619	(26,878,488)	141,547,131	(2,638,564)	138,908,567	26,409	138,934,976	-	138,934,976
16	Off System Sales Expense	Exhibit 3 / 103	3,589,350	(3,589,350)	-	-	-	-	-	-	-
17	Gas Used in Company Operations		(379,743)	379,743	-	-	-	-	-	-	-
18	Operating and Maintenance Expense	Exhibit 4 / 104	188,447,880	1,178,920	189,626,800	(2,406,284)	187,220,516	10,507,278	197,727,794	1,139,534	198,867,328
19	Depreciation and Amortization	Exhibit 5 / 105	65,429,359	6,041,289	71,470,648	10,012,085	81,482,733	12,665,989	94,148,722	-	94,148,722
20	Net Salvage Amortized	Exhibit 5 / 105	5,815,758	(1,156,923)	4,658,835	(219,055)	4,439,780	244,287	4,684,067	-	4,684,067
21	Taxes Other Than Income Taxes	Exhibit 6 /106	3,514,764	216,652	3,731,416	(20,862)	3,710,554	114,991	3,825,546	-	3,825,546
22	Total Operating Revenue Deductions		434,842,987	(23,808,157)	411,034,830	4,727,320	415,762,150	23,558,954	439,321,104	1,139,534	440,460,639
23	Operating Income Before Income Taxes		173,076,197	(11,574,483)	161,501,713	(4,567,602)	156,934,112	(23,485,641)	133,448,470	99,227,263	232,675,733
24	Income Taxes	Exhibit 7 / 107	24,860,731	4,995,237	29,855,968	(5,504,941)	24,351,027	(7,824,406)	16,526,621	24,292,365	40,818,986
25	Investment Tax Credit	Exhibit 7 / 107	(299,568)	-	(299,568)	12,456	(287,112)	29,697	(257,415)	-	(257,415)
26	Operating Income		148,515,034	(16,569,720)	131,945,313	924,883	132,870,197	(15,690,932)	117,179,264	74,934,898	192,114,162
27	Rate Base	Exhibit 8 / 108	1,966,199,619	(115,661,862)	1,850,537,758	205,474,499	2,056,012,257	345,414,762	2,401,427,019	-	2,401,427,019
28	% Rate of Return Earned on Rate Base		7.55%		7.13%		6.46%		4.88%		8.00%

Columbia Gas of Pennsylvania, Inc.
Calculation of Proforma Interest Expense
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.	Description	Pro Forma (1) $
	FTY Calculation	
1	Rate Base	2,056,012,257
2	Weighted Cost of Short &	
3	Long Term Debt	2.070%
4	Interest Expense	42,559,454
	FPFTY Calculation	
5	Rate Base	2,401,427,019
6	Weighted Cost of Short &	
7	Long Term Debt	2.070%
8	Interest Expense	49,709,539

Columbia Gas of Pennsylvania, Inc.
Rate of Return on Rate Base
Proposed Revenue Requirement
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.	Description	Detail	Amount
			(1)
			$
1	Proforma Rate Base at Present Rates		2,401,427,019
2	Return on Rate Base		8.000%
3	Total Requirement		192,114,162
4	Less: Net Operating Income at Present Rates		117,179,264
5	Net Required Operating Income		74,934,897
6	Revenue Conversion Factor		1.33938660
7	Gross Revenue Requirement		100,366,797
8	Revenue Conversion Factor:		
9	Operating Revenue		1.00000000
10	Plus: Late Payments		0.00191300
11	Less: Uncollectibles		0.01135370
12	Income Before State Taxes		0.99055930
13	State Income Tax Effect Tax Rate		0.04591630
14	Less: State Income Tax		0.04548282
15	Income Before Federal Taxes		0.94507648
16	Less: Federal Tax @ 21%		0.19846606
17	Adjusted Operating Income		0.74661042
18	Revenue Conversion Factor		1.33938660

Exhibit No. 102
Schedule 3
Page 6 of 6
Witness: K. K. Miller

Columbia Gas of Pennsylvania, Inc.
Additional Revenue Requirement Adjustments
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2021

Line No.		Description	Amount (1) $
1		Additional Revenue Requirement	100,175,162
2	Plus:	Late Payments	191,635
3		Total Revenue Requirement	100,366,797
4	Less:	Uncollectible Accounts Expense	
5		Line 3 X Uncollectible Rate	1,139,534
6		Income Before State Income Tax	99,227,263
7		State Income Taxes	
8		Exh 107, Pg 17, Col 3 Less Exh 107, Pg 17, Col 2	4,372,962
9		Income Before Federal Income Tax	94,854,301
10		Federal Income Taxes	
11		Line 9 Times 21%	19,919,403
12		Net Required Operating Income	74,934,898

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 11/30/20, FPFTY = Fully Projected Future Test Year TME 12/31/21
Labor Adjustment Summary (Normal Pay Only)

Line No.	Description	Reference	AS FILED Amount (1) $	Revised Per OCA-05-017 Amount (2) $
	FTY Adjustment			
1	FTY Total Labor Adjustment		1,090,167	1,090,167
2	O&M Percentage	Budget System O&M Factor	49.98%	54.91%
3	FTY O&M Labor Annualization Adjustment	Ln 1 x Ln 2	544,916	598,611
4	Lobbying Adjustment		(8,698)	(8,698)
5	FTY O&M Labor Adjustment		536,218	589,913
	FPFTY Adjustment			
6	FPFTY Total Labor Adjustment		996,176	996,176
7	O&M Percentage	Budget System O&M Factor	49.96%	54.87%
8	FPFTY O&M Labor Annualization Adjustment	Ln 6 x Ln 7	497,691	546,602
9	Lobbying Adjustment		(8,959)	(8,959)
10	FPFTY O&M Labor Adjustment		488,732	537,643

Line No.		Labor As Filed (1) $	OCA-05-017 Adjustments (2) $	OCA-05-017 Labor as Adjusted (3) $	Merit Change to 0% For Directors and Above for 2020 Adjustments (4) $	Cumulative OCA-05-17 and Merit Elimination for Directors & Above Adjusted (5) $	Merit Changes For Other CPA and NCSC Employees for 2020 Adjustments (6) $	Cumulative OCA-05-17, Merit Elimination for Directors & Above and Other Employee Merits Adjusted (7) $
			Labor Adjustment #1		Labor Adjustment #2		Labor Adjustment #3	
	CPA Direct Labor							
1	Normalized HTY Labor	39,142,312	-	39,142,312	-	39,142,312	-	39,142,312
2	Budget Adjustment	(2,145,312)	763,690	(1,381,622)	(14,603)	(1,396,225)	(15,577)	(1,411,802)
3	Annualization Adjustment	536,218	53,695	589,913	(14,603)	575,310	(15,577)	559,733
4	Normalized FTY Labor	37,533,218	817,385	38,350,603	(29,206)	38,321,397	(31,153)	38,290,243
5	Budget Adjustment	1,505,782	(857,881)	647,901	2,078	649,979	2,216	652,195
6	Annualization Adjustment	488,732	48,911	537,643	(2,932)	534,711	(3,128)	531,583
7	Normalized FPFTY Labor	39,527,732	8,415	39,536,147	(30,061)	39,506,086	(32,064)	39,474,022
	NCS Labor Billed to CPA							
8	Normalized HTY Labor	20,569,337	-	20,569,337	-	20,569,337	-	20,569,337
9	Budget Adjustment	1,333,044	-	1,333,044	(58,342)	1,274,701	(44,833)	1,229,869
10	Annualization Adjustment	327,753	-	327,753	(58,342)	269,411	(44,833)	224,578
11	Normalized FTY Labor	22,230,134	-	22,230,134	(116,685)	22,113,449	(89,665)	22,023,783
12	Budget Adjustment	918,324	-	918,324	8,265	926,589	6,351	932,940
13	Annualization Adjustment	289,336	-	289,336	(11,766)	277,570	(9,041)	268,529
14	Normalized FPFTY Labor	23,437,793	-	23,437,793	(120,185)	23,317,608	(92,355)	23,225,252
15	**Total FTY**	**Line 4 + Line 11**	**817,385**		**(145,891)**		**(120,819)**	**550,675**
16	**Total FPFTY**	**Line 7 + Line 14**	**8,415**		**(150,246)**		**(124,420)**	**(266,251)**

		CPA Employees					
Line Number		**Annual Assumed In Case at 3%**		**Annual Revised Amount**		**FTY Decrease**	**FPFTY Decrease**
		(1)		**(2)**		**(3)=(2)-(1)**	**(4)=(3*3%)+(3)**
1	Directors and Above Merit Increase	53,189.57	1/	-		(53,189.57)	(54,785.25)
2	O&M Percentage					54.91%	54.87%
3	Net Change to O&M Directors and Above					(29,206.39)	(30,060.67)
4							
5	Other Merit Changes	463,028.00	2/	406,293.00	2/	(56,735.00)	(58,437.05)
6	O&M Percentage					54.91%	54.87%
7	Net Change to O&M Other Merit Changes					(31,153.19)	(32,064.41)
8							
9	**Total Change for CPA Employees**					**(60,360.00)**	**(62,125.00)**

1/ Represents 3% of annualized wages for all employees at Director and above at November 30, 2019.
2/ Per Kimberly Cartella, Director of Compensation.

Line Number		Annual Assumed In Case at 3% (1)		Annual Revised Amount (2)		FTY Decrease (3)=(2)-(1)	FPFTY Decrease (4)=(3*3%)+(3)
		NCSC Employees					
1	Directors and Above Merit Increase	996,563.83	1/	-		(996,563.83)	(1,026,460.75)
2	CPA Percentage					14.96%	14.96%
3	Allocation to CPA					(149,063.03)	(153,534.92)
4	O&M Percentage					78.28%	78.28%
5	Net Change to O&M Directors and Above					(116,684.90)	(120,185.45)
6							
7	Other Merit Changes	3,281,999.87	2/	2,516,199.90	2/	(765,799.97)	(788,773.97)
8	CPA Percentage					14.96%	14.96%
9	Allocation to CPA					(114,546.06)	(117,982.44)
10	O&M Percentage					78.28%	78.28%
11	Net Change to O&M Other Merit Changes					(89,665.40)	(92,355.36)
12							
13	**Total Change for NCSC Employees**					**(206,350.00)**	**(212,541.00)**

1/ Represents 3% of annualized wages for all employees at Director and above at November 30, 2019.
2/ Per Kimberly Cartella, Director of Compensation.

COLUMBIA STATEMENT NO. 5-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2020-3018835
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

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

AUGUST 26, 2020

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 intervenor Office of Consumer Advocate witness David J. Effron regarding his recommended adjustments to plant in service and depreciation expense calculated as of December 31, 2021.

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 $76,783,000 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 $76,783,000 to plant in service as of December 31, 2021, he utilizes the composite depreciation rate of 2.55%, which was calculated as of December 31, 2021 including the $76,783,000 plant in service amount, to calculate his recommended reduction to depreciation expense of $1,958,000. This fails to recognize that the composite depreciation rate changes as the amount and composition of plant changes.

Q. Are you addressing Mr. Effron's proposed reduction to plant in service?

A. No, not specifically as Company witnesses, Nicole Shultz and Robert Kitchell, will address Mr. Effron's reductions to plant in service. My rebuttal focuses on the issues of depreciation expense and process in developing test year depreciation rates and expense.

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, 2021. However, Mr. Effron utilizes the 2.55% 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, 2021 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. Does this complete your prepared rebuttal testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 6-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
NICOLE M. SHULTZ
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

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 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 FPFTY rate base. I will also address the recommendation of Ethan H. Cline, witness for the Bureau of Investigation and Enforcement, that the Company provide an update to Columbia Exhibit No. 108, Schedule 1.

Q. Please summarize Mr. Effron's adjustment to the FPFTY rate base.

A. Mr. Effron asserts that the Company's forecasted plant additions for the FPFTY (i.e., 2021) are unreasonable because they exceed the Company's forecasted plant additions for 2020 and the actual plant additions made in 2018 and 2019. As such, Mr. Effron recommends that the Company's forecasted plant additions for 2021 be disregarded and that instead the forecasted plant additions for the FPFTY be based on an estimate that is calculated based on the average plant additions for the years 2018 through 2020. Mr. Effron's recommended approach to estimating the FPFTY plant additions results in a negative adjustment of $76,783,000 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 FPFTY? Please explain.

A. No, I do not. Mr. Effron's recommendation to base the Company's forecasted plant additions for the FPFTY on the average plant additions for the years 2018 through 2020 stems merely from the Company's forecasted plant additions for the FPFTY exceeding the plant additions for the three proceeding years. Mr. Effron has offered no evidence that the Company will not complete its 2021 forecasted plant additions, and past experience demonstrates the Company's success in executing its capital budgets[1]. Moreover, Company witness Kitchell, in his rebuttal testimony, justifies the Company's 2021 forecasted plant additions by explaining how the planned additions are both necessary and reasonable, and related directly to safety and reliability. Mr. Kitchell further testifies that the Company is prepared to execute the planned additions in 2021. Mr. Effron's recommendation should therefore be rejected as it is not proper to base the 2021 forecasted plant additions on a historical average when the Company has offered a forecast supported by an actual plan.

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[1] See Columbia Statement No. 14-R, Table 1, for a comparison between plant addition projections and plant addition actuals from 2016 through 2021.

Q. What is the percentage of 2021 additions that Mr. Effron is proposing as an adjustment to Plant in Service?

A. The proposed adjustment to FPFTY Plant in Service by Mr. Effron represents approximately 22% of the $338,558,968 forecasted plant additions.

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. Clines recommends that the Company update Exhibit No. 108, Schedule 1 no later than April 1, 2021, to include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2020, as well as provide an additional update for actuals through December 31, 2021 by April 1, 2022. The Company is agreeable to proving such updates to Exhibit 108.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 7-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

REBUTTAL TESTIMONY OF
MICHAEL J. DAVIDSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. Michael J. Davidson, 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. My rebuttal testimony responds to several issues raised by I&E witnesses Kokou M. Apetoh and Lassine Niambele as part of their direct testimony. First, I will respond to witness Apetoh and Niambele's comments regarding both the Distribution Integrity Management Plan ("DIMP") and risk reduction. Then, I will address Mr. Apetoh's recommendations regarding leakage, damage prevention and field assembled risers. Lastly, I will address the Office of Consumer Advocate ("OCA") witness David J. Effron's opposition in regards to Columbia's safety related initiatives for the FPFTY.

II. DIMP/Risk Reduction

Q. Please provide an overview of Columbia's current DIMP program.

A. DIMP is a company-specific plan - developed by the company - for the purpose of identifying risk, developing plans and implementing actions to reduce identified risk and to evaluate the effectiveness of risk reduction efforts. The Company began its efforts to investigate and analyze its system and proceeded with an enhanced pipeline safety program before the DIMP regulation was in effect. As such, Columbia has created a robust DIMP that exceeds the minimum standards of the regulations and the Company has been asked by I&E to share its DIMP and best practices with other Pennsylvania gas utilities. The Pennsylvania Public Utility Commission should consider these efforts in determining the effectiveness of Columbia's management.

Q. Is Columbia currently in compliance with all federal code and regulation as it relates to DIMP?

A. Yes. Columbia is currently in compliance with and has fulfilled and adhered to all requirements of DIMP as mandated under CFR 49 Part 192.1001 – 192.1015, Subpart P of the Code of Federal Regulations.

Q. In testimony, witness Niambele states that "Columbia's riskiest asset groups cannot be compared year over year." Do you agree with witness Niambele?

A. I do not. Columbia's riskiest asset groups can be and are compared year over year. Annually, the Company performs a review of its DIMP program and corresponding DIMP risk model. During the annual review of the risk model for the 2020 DIMP Plan, Subject Matter Experts[1] ("SMEs") review and compare the risk levels for each

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[1] SMEs are persons knowledgeable about design, construction, operations, or maintenance activities, or the system characteristics of a particular distribution system. Designation as an SME does not necessarily require specialized education or advanced qualifications. Some SMEs may possess these characteristics, but detailed knowledge of the pipeline system gained by working with it over time can also make someone an SME. SMEs

asset-threat combination, including the Company's riskiest asset groups, (such as bare steel) from the past year. In order to determine what the risk level (i.e., Low, Medium or High) should be for those asset groups in the upcoming DIMP plan year, the Company's SMEs compare the risk levels for its riskiest asset groups against the previous two years' risk levels as a factor in their decision making. The Company reviews and compares the historic risk levels for its asset groups as prompted by a recommendation from the Commission's Gas Safety Division in the Company's 2018 PUC DIMP inspection.

Q. In testimony, witness Niambele states that 'Columbia's risk reduction is based on a qualitative risk reduction instead of a quantitative value meaning the Company risk ranking is not based on numerical values. Based on "High", "Medium" and "Low" categories, witness Niambele suggests that the Company cannot demonstrate whether the system risk is decreasing.' Do you agree with witness Niambele?

A. I do not. The Company does have quantitative risk ranking. The DIMP system level risk model is a data-driven/numerical, SME-validated risk model. The risk scores are calculated numerically from leakage rates, damage data, and other sources. This numerical data is incorporated into a separate probability and consequence score, which is then further calculated into a total risk score. The final risk score is a

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may be employees, consultants or contractors, or any appropriate combination. They are selected based on their ability to drive change and thus are provided such information in order to look at trends for analysis.

quantitative value, and it determines which risk level (High, Medium, Low) that each asset-threat combination is given. The risk score is not shown in the published risk model in order to encourage SMEs to treat all High risks with the same urgency. Nevertheless, the Company's risk ranking is quantitative.

Q. Can you further clarify the Company's position as it relates to DIMP and what DIMP is for?

A. Yes. The Company utilizes its DIMP to identify its riskiest asset groups and then to prioritize and focus its efforts to address its riskiest asset groups. Seemingly, I&E views DIMP as only a scoring mechanism to measure risk from year to year. The Company notes that DIMP is not just a tool to assess risk on individual pipe segments and determine yearly project plans. DIMP is a tool to assess and prioritize risk on asset groupings over time, especially taking into account that risks can and do change over time.

Q. In testimony, witness Niambele notes that "Issues were discussed during the Company's 2018 annual DIMP audit and resulted in the issuance of a non-compliance letter in August of 2018." Do you agree with the issuance of the non-compliance letter?

A. No, Columbia does not agree with the issuance of the non-compliance letter (see Exhibit MJD-1R attached hereto) in August of 2018. It is the Company's understanding that the non-compliance letter was not intended to show non-compliance with DIMP regulations, but was merely the Gas Safety Division's platform to recommend improvements to Columbia's DIMP. Further, Columbia's plan incorporates the 7 key elements of DIMP and Columbia provided data to show that its plan was compliant with 49 CFR Part 192 Subpart P. Therefore, Columbia disagrees that its plan was non-compliant and as shown in Exhibit MJD-1R starting on page 5, the Company outlined how its DIMP plan was compliant with the DIMP regulations.

Q. What steps has Columbia taken in response to the non-compliance letter to address I&E Gas Safety Division's concerns?

A. Even though the Company's DIMP was compliant with DIMP regulations at the time the Gas Safety Division issued the letter provided as Exhibit MJD-1R attached hereto, the Company did review and address the concerns in that letter.

The Gas Safety Division's letter first stated a concern over leak/incident history and using historical data to assess leakage. As such, in the Company's response to the Gas Safety Division's letter, the Company explained that it uses a 5 year baseline for its leak performance measures and that it will consider expanding its baselines for performance measures going forward, while taking the quality of the available data into consideration (See Exhibit MJD-1R for a copy of the Company's response letter).

Further, the letter stated that the Company must study and evaluate assets in smaller groupings, such as size and/or pressure. The DIMP Plan already addresses this by using Optimain, a project prioritization tool, as a way to evaluate risk in smaller segments based on location, pressure and other factors. This separate but parallel approach to risk ranking allows DIMP to assess assets through different lenses to allow for the most effective risk management strategy.

The letter also mentions that the DIMP risk model has not normalized risk ranking scores between the data-driven scores based on leakage and other sources versus the scores that are assigned to an asset/threat combination after SME's adjust the risk ranking. It is important to understand that these two types of numerical scores are used as inputs so that a final risk level (High, Medium, Low) can be assigned to the asset/threat combination. Ultimately, having the most accurate risk level assigned to the asset/threat combination is of utmost importance because it is what signals the DIMP steering team to create new remediation actions and programs. There is still work to be done to determine what the numerical risk score should be when an SME adjusts the risk level on an asset/threat combination, but to avoid unnecessary changes to the risk levels, the SME Risk Evaluation Form is used to validate any and all risk level changes. See Exhibit MJD-2R for a copy of the SME Risk Evaluation Form.

Finally, the Gas Safety Division's letter recommended that the Company study and evaluate specific assets which pose a higher risk for the threat of excavation damage. The Company disagreed with this recommendation under the logic that the threat of excavation damage can strike anywhere in the system, and that, generally speaking, the type of asset will not impact where an excavation damage occurs.

Furthermore, damage prevention efforts are applied holistically to the system to reduce the overall threat of excavation damage and are not targeted or prioritized to specific assets.

Q. What are witness Apetoh's recommendations with respect to DIMP and risk reduction?

A. On pages 6 and 7 of his testimony, Mr. Apetoh offers four recommendations for DIMP and risk reduction: 1) focus specifically on the other risk factors that have risen from 2017 to 2019; 2) develop a process and procedure to normalize the two different risk ranking systems it uses so the effectiveness of the DIMP plan can be evaluated; 3) conduct risk rankings with its historical data prior to 2016 to better evaluate trends and changes in risks to its system; and 4) update Section 7.1.2.2 of its DIMP Plan to reflect the inclusion of historical data in the evaluation of its risks.

Q. Mr. Apetoh recommends that the Company focus on other risk factors that have risen from 2017 to 2019. Is Columbia focused on the other risk factors that have risen from 2017 to 2019? If so, please explain.

A. Yes. The Company has maintained, and continues to maintain focus on all distribution system risk factors which include leak prevention, excavation damages, poor records, and field assembled risers mentioned by Mr. Apetoh. As part of Columbia's DIMP, system risk factors are managed and addressed through additional/accelerated actions which are actions the Company undertakes to go above and beyond Part 192 requirements or current utility practices intended to reduce one or more threats to distribution integrity. Below are a few examples of accelerated actions the Company is utilizing to mitigate the risk factors that are increasing.

1. <u>Leak Prevention</u>: Columbia began an accelerated pipe replacement program in 2007 to address bare steel, cast iron and wrought iron facilities. The accelerated action targets threat(s) and risk factor(s) related to external corrosion, natural forces (e.g. frost) and cast iron bell joint failures.
2. <u>Excavation Damages</u>: Columbia implemented a Frequent Damager Program in 2012. This accelerated action was created to address the problems caused by and the risks associated with companies or individuals responsible for causing multiple damages to Columbia's facilities within the public right-of-way. While this effort cannot entirely eliminate frequent damagers (or frequent damages), it is designed to respond quickly with escalating levels of intervention to those few contractors who fail to respect utility property or the applicable state one call laws.
3. <u>Poor Records</u>: In March 2010, Columbia updated its Gas Standard (GS 3010.050 – Installation of Pipe in a Ditch) to include the installation of electronic markers. The electronic markers provide a means to accurately locate pipelines that are difficult to locate, and to locate certain pipeline features (e.g. segments of the pipeline deeper than 15 feet, end of line

locations, casing ends and other situations where it is known that a facility is difficult to locate). This accelerated action targets threat(s) and risk factor(s) related to the probability of excavator error due to poor records and locator error.

4. Field Assembled Risers: In 2015, Columbia implemented a company owned field assembled riser replacement program to address the threat(s) and risk factor(s) associated with field assembled riser failures. On pages 18-21 and 22-23 of my rebuttal testimony, I will also describe Columbia's efforts to address customer owned field assembled risers that are prone to fail.

Q. Mr. Apetoh recommends that the Company should "develop a process and procedure to normalize the two different risk ranking systems it uses so the effectiveness of the DIMP plan can be evaluated." Does Columbia use two different risk scores for DIMP risk ranking?

A. No. The Company does not use two different risk scores for DIMP risk ranking. The Company has two different inputs that it uses in its one DIMP risk score. One input involves the use of quantitative data such as leakage rates or damage data and the other input involves qualitative data from SMEs. Therefore, The Company does not refer to data driven results and SME issued data as two "risk ranking scoring systems", but rather as two types of inputs in one DIMP risk model.

Q. Can Columbia evaluate the effectiveness of its DIMP Plan? Please explain.

A. Yes. The Company utilizes performance measures to evaluate the effectiveness of the DIMP Plan and particularly the programs put into place as a result of acknowledging the highest risks in its system. There are 22 performance measures that are required by DIMP regulation, Part 192.1007(e). In addition to those measures, the Company has selected other measures in order to evaluate the effectiveness of the accelerated actions or view other high level trends. The performance measures that the Company uses to evaluate the effectiveness of the DIMP plan include, but are not limited to: the number of corrosion leaks on bare steel services, the miles of cast iron pipe in the system, the number of excavation damages per thousand locates called in, and the percentage of risers that have been replaced.

Q. Mr. Apetoh recommends that the Company conduct risk rankings with its historical data prior to 2016 to better evaluate trends and changes in risks to its system. Has Columbia conducted risk rankings with its historical data in order to better evaluate trends and changes in risks to its system?

A. Yes. However, midway through 2016, a significant number of process changes were made to the collection of leakage data and the leakage data quality assurance/quality control processes. These changes affected the threat and/or asset with which each leak is compared. Therefore, it is not possible to make a fair comparison of risk rankings for the current year's leakage data against leakage data prior to 2016. So, the Company does use historical leakage data for trending analysis, but only from 2016 forward.

Q. Mr. Apetoh also recommends that the Company update Section 7.1.2.2. of its DIMP Plan. Has Columbia updated Section 7.1.2.2 of its DIMP Plan to reflect the inclusion of historical data in the evaluation of its risks?

A. Yes. Columbia has updated Section 7.1.2.2: Actual Consequence of Failure (COF) of its DIMP Plan as recommended by I&E. The update expands the use of incident data by giving a higher consequence of failure score to asset-threat combinations that are related to incidents in the Company occurring over the past five years.

III. Leakage

Q. Can you further explain Columbia's statistical trending for leakage found on its system for years 2017 through 2019?

A. As represented in witness Apetoh's direct testimony, Columbia's overall leak trajectory for 2015 through 2019 has trended downward approximately 15.6% during the five year period. In contrast, Columbia did experience a slight increase over the three year period of 2017 through 2019 which can be attributed to a couple of key factors that are worth noting. First, Columbia continues to aggressively replace aging bare steel, cast iron and wrought iron through its accelerated infrastructure replacement program, which is addressed in Columbia witness Kitchell's direct testimony (Columbia Statement No. 14). However, the impact of these efforts is expected to be gradual over the period of the program, considering that the remaining bare steel, cast iron and wrought iron to be replaced continues to degrade at an accelerated pace. Secondly as can be seen from the table below, Columbia surveyed approximately 3,100,000 feet more in 2019 than it completed in 2017, or 13.8% more feet surveyed, which resulted in an increase to the number of leaks found.

2017	**2018**	**2019**
22,541,033	23,864,367	25,661,113

Q. On Page 4 of his direct testimony, witness Apetoh performs an analysis that calculates leaks per mile of priority pipe, and he concludes that Columbia has experienced a 9.69% increase during the period 2015-2019, and a 6.8% increase during the period 2017-2019. Do you agree with witness Apetoh's analysis?

A. No. Columbia understands the methodology which Mr. Apetoh applied, but does not agree that the analysis is a true representation of priority pipe leakage due to two factors that he has not considered. First, the annual leaks found, per Columbia's response to I&E-GS-003, which Mr. Apetoh provided as I&E Exhibit 5, Schedule No. 1, and which served as the basis for his calculation, are not limited to priority pipe. Rather, the data that Columbia provided to Mr. Apetoh regarding annual leaks found included all probable leak sources, (e.g. mains, services and station piping/meter setting), as well as leaks caused by facility damages. Secondly, pipe material must also be considered and Columbia only captures pipe material data at the time the leak is cleared and not found. Therefore, Mr. Apetoh's calculation overstates the percent change of leaks associated with priority pipe.

Q. What are witness Apetoh's recommendations with respect to leakage?

On page 12 and 13 of his testimony, Mr. Apetoh offers two recommendations for leakage. He recommends that Columbia: 1) perform a root cause analysis to determine why the number of leaks found does not correlate with the amount of pipeline replacement for the past four years; 2) present the results of that analysis to I&E Pipeline Safety, to include any corrective actions the Company takes, no later than September 30, 2021.

Q. Does Columbia agree with witness Apetoh's recommendations regarding leakage?

A. Not entirely. Columbia agrees that as a prudent operator, this type of root cause analysis is essential to understanding and evaluating pipeline system risks, and Columbia currently completes its own analysis through its DIMP under CFR 49 Part 192.1001-192.1015, Subpart P of the Code of Federal Regulations and through operations work planning processes. As explained earlier on pages 10-11, Columbia has evaluated its trending data regarding leakage found over the last three years and will continue to analyze data as it becomes available. Columbia does not believe a formal root case analysis is necessary at this time as it already evaluates leakage data in its current DIMP and operations work planning processes.

IV. Damage Prevention

Q. What are witness Apetoh's recommendations with respect to damage prevention?

A. On page 13 and 14 of his direct testimony, Mr. Apetoh offers four recommendations for Columbia's damage prevention. He recommends that Columbia: 1) finish updating its maps and records by the end of 2021 if the Commission approves its request for an additional O&M cost of $491,000; 2) provide documentation of the completion of the map update to I&E Pipeline Safety no later than June 30, 2022; 3) use its senior operators and damage prevention staff to tailor training programs that better suit Columbia's needs; and 4) train its locating personnel, including third-party contractors, on the same locating equipment used in the field.

Q. Mr. Apetoh recommends that Columbia update its maps and records by the end of 2021 and provide documentation to I&E. Can Columbia reasonably expect to finish updating its maps and records by the end of 2021 and provide documentation of the completion to I&E Pipeline Safety by June 30, 2022?

A. No. While Columbia continues to enhance its current processes, the Company will also need to add personnel to complete the mapping and records updated. The Company has requested an additional $491,000 in O&M for the added personnel.

Although the Company believes it will make progress in the FPFTY, Columbia feels the program will require ongoing efforts and resources and therefore, the Company cannot guarantee completion of its maps and records by the end of 2021.

Furthermore, Columbia will provide documentation to I&E Pipeline Safety as soon as it is available, and will keep I&E apprised of its progress. I note that OCA witness Effron proposes to disallow the additional $491,000 for the additional personnel the Company would need to update its maps and records. This disallowance would further delay the Company's ability to update its records.

Q. Mr. Apetoh recommends that the Company use its senior operators and damage prevention staff to tailor training programs that better suit Columbia's needs. What efforts has Columbia taken to enhance damage prevention training programs?

A. Columbia employs eight Damage Prevention Specialist ("DPS") with responsibility to focus on meeting contractors on site to discuss 811 (call before you dig) laws and to train them on hand digging responsibilities related to the Pa One Call law in order to avoid damaging buried facilities. Recently, the DPS employees have been utilizing an internal process within our One Call ticket management system, UtiliSphere, which utilizes an algorithm to grade the level of risk on a given One Call ticket. The algorithm utilizes certain criteria to perform the risk modeling, for example, the Contractor's history, pressure of gas in the area, type of material of gas line, and type of work being completed. This provides Columbia's DPS's with the opportunity to identify and get ahead of high risk types of excavation to complete a job site visit.

In addition, Columbia has added one Damage Prevention Consultant who focuses primarily on Alleged Violations Reports ("AVR"). The AVR is a reporting requirement that went into effect April 28, 2017 when enforcement transferred from the Pennsylvania Department of Labor and Industry to the Commission due to a legislative change of the Pa One Call Law. This enforcement change requires all damages to a facility owner's lines to be reported through the Pa One Call system by all parties involved (e.g. Facility Owner, Project Owner and/or Designer). The Company's Damage Prevention Consultant is responsible for compiling facility damage data submitted through the Pa One Call system and then submitting a completed AVR to the Commission's Damage Prevention Committee for evaluation.

Q. Mr. Apetoh recommends that the Company train its locating contractors. Does Columbia utilize third-party contractors for facility locating?

A. No. Since 2012, Columbia uses Company employees for the vast majority of its facility locating needs with one exception. Columbia's outside contractors use their own personnel to locate facilities on capital projects for the infrastructure replacement program.

Q. Mr. Apetoh recommends that the Company train its locating personnel on the same equipment to be used for locating in the field. Does

Columbia train locating personnel on the same or equivalent locating equipment used in the field?

A. Yes, Columbia trains its locating personnel on the theory and practice of executing a valid facility locate request at the Company's advanced training facility in Monaca, Pennsylvania. The Company trains its locating employees with the same equipment the employees would be using in the field. Once an employee has successfully completed that training, the employee will then go back to their work location to perform on-the-job training with a seasoned locator where he or she will build familiarity with the technology they will be utilizing on a daily basis.

V. Field Assembled Risers

Q. In testimony, witness Apetoh suggests that field assembled risers are assembled by only Company employees and also states "The increasing number of failed field assembled risers is a testament to the importance of personnel training." Do you agree with the conclusion drawn by witness Apetoh?

A. Not entirely. Initially, it is important to note that most risers were not installed by the Company. Similar to customer-owned service lines in Western Pennsylvania, Columbia does not own risers in most of its service territory. In most cases, Columbia and/or its approved contractors would have only installed risers on Company-owned customer service lines, not customer-owned customer service lines. On Columbia's system, customers own approximately 70% of the customer service lines across

Columbia's service territory and this number is approximately the same for risers. That means that plumbers or contractors who are not working for or hired by the Company, but instead are hired by customers, would have installed the majority of customer service lines in Columbia's territory.

Columbia acknowledges the potential that some of the field assembled risers were not properly installed, however this is a legacy issue which Columbia is proactively remediating. In 2007, Columbia stopped installing field assembled risers and, since then, has only installed factory assembled risers. Therefore, contrary to Mr. Apetoh's suggestion, current personnel training is not an issue with respect to the installation of field assembled risers installed by Columbia.

There are also other factors aside from improper installation that cause risers to fail. Weather impacts field assembled risers especially in extremely cold weather. During the "polar vortex" of 2014-2015, Columbia experienced approximately 100 field assembled riser failures in one township of Columbia's service territory on customer-owned facilities. Following these failures, Columbia completed a failure investigation on a number of the failed risers, and most of the failed risers were caused by heavy frost and cold. Additionally, the gaskets in field assembled risers are susceptible to cracking and the retainer ring(s) can become deformed over time.

Therefore, while the Company acknowledges the possibility that some riser issues could be attributed to installation error, the Company points out that the majority of risers were not installed by Company personnel and therefore, cannot be attributed to installation error. So, the Company disagrees that training is the cause of riser failures.

Q. What are witness Apetoh's recommendations with respect to field assembled risers?

A. On page 12 of his testimony, Mr. Apetoh offers three recommendations for field assembled risers. He recommends that Columbia: 1) complete updating its records, which will allow Columbia to identify the locations of all field-assembled risers including those on customer-owned service lines; 2) complete inspection of all field-assembled risers in the Company's system as soon as possible; and 3) develop a plan to replace all of the field-assembled risers in its system, including those on customer-owned service lines.

Q. Does Columbia agree with witness Apetoh's recommendations regarding field assembled risers?

A. Yes, Columbia agrees with the recommendations with respect to field assembled risers and has already taken steps to proactively address the suggested recommendations. As a result of past field assembled riser failures, Columbia developed and implemented a program to identify and address the risk of field assembled riser failures on its system. In 2015, the Company started the process of surveying both company owned and customer owned service lines to identify the location and quantity of field assembled risers on its system, which was completed in

2017. Furthermore, Columbia has and continues to inspect those identified field assembled risers as part of the annual program leakage survey.

In regards to developing a plan to replace all the field assembled risers, Columbia's approach is first to address certain manufacturers of field assembled risers that are more prone to failure. In 2015, Columbia began replacing these field assembled risers identified on company owned service lines. Recognizing the same risk existed on customer owned facilities, the Company petitioned for a waiver[2] to address customer owned field assembled risers, which was approved by the Commission on December 6, 2018. Subsequent to the Commission's approval, the Company began replacing customer owned field assembled risers in 2018. Furthermore, Columbia responded to interrogatories relating to the Company's plan to address customer owned field assembled risers which I will later discuss on page 20. See Exhibit MJD-3R attached hereto.

VI. Safety Related Initiatives

Q. In his direct testimony, witness Effron states, "It is not clear why the spending on the cross bore program must more than double from 2020 to 2021 after having been at reduced level from previous years in both 2019 and 2020." Do you agree with witness Effron?

[2] Petition of Columbia Gas of Pennsylvania, Inc. for Limited Waivers of Certain Tariff Rules Related to Replacement of Customer Service Lines and Field Assembled Risers (Docket No. P-2018-2641560)

A. No. Given the program results to date, cross bores are identified as a high risk in Columbia's DIMP plan and the Company deems it necessary to accelerate the pace of its cross bore program. At current spend levels, Columbia is on a 68 year pace to investigate for cross bores, which is far too long for this growing concern. As represented in my direct testimony, Columbia is requesting an incremental $1,400,000 annually to reduce the projected timeframe by more than half, which in turn would result in a 31 year pace to investigate all cross bores on its system.

Additionally, since 2014, Columbia has budgeted $1,300,000 annually for the cross bore program and has proved to effectively meet as well as exceed historical year's projected targets. Furthermore in response to Mr. Effron's assertion that spend levels for years 2015 through 2018 were higher than 2019 and 2020, Columbia reallocated resources from other work activities to address this high risk concern in those years. In 2019, Columbia met the expected target of $1,300,000 and is projected to spend approximately $1,500,000 in 2020 on its cross bore program.

Q. In his direct testimony, witness Effron states, "The Company has presented no evidence that customer owned field assembled risers replaced in the FPFTY will be any greater than the customer owned field assembled risers replaced in the HTY." Do you agree with witness Effron?

A. No. Columbia has provided Mr. Effron the necessary information to support the customer owned field assembled riser program, which included projected units to be completed in the FPFTY and an estimated cost per unit which was also supported by Columbia's historical customer owned field assembled riser replacement costs (see Exhibit MJD-3R). Furthermore, as stated in Columbia witness Nancy Krajovic's rebuttal testimony (C0lumbia Statement No. 9-R), incremental funding is necessary in order to increase the customer owned field assembled riser replacements. Without the incremental funding, Columbia would need to decrease and/or eliminate other risk reducing or compliance activities has and doing so has the potential to negatively impact Columbia's overall risk profile.

Q. In his direct testimony, witness Effron recommends the elimination of Columbia's proposed adjustments for projected safety initiatives expense. Do you agree with witness Effron?

A. No. Columbia is fully committed to delivering safe and reliable service to its customers and to protect the communities that it serves. In order to meet these fundamental commitments, Columbia is requesting incremental funding in the FPFTY to address key safety initiatives that the Company deems essential to reducing risk to its system. Despite Mr. Effron's assertions, the Company has provided the information necessary to support its safety initiatives related to the acceleration of its cross bore program and its customer-owned field assembled riser replacement program, as well as the implementation of the Picarro leak detection system. Moreover, I&E witnesses Apetoh and Niambele support the acceleration and implementation of the Company's safety initiatives with the information provided by the Company. Therefore, Mr. Effron's basis for elimination of expenses in the FPFTY revenue requirement associated with these essential safety initiatives, should be rejected.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

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-2020-3018835

August 26, 2020

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

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

A. My name is Paul 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 April 24, 2020.

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 St. 3), Christopher Keller, a witness appearing on behalf of the Commission's Bureau of Investigation and Enforcement ("I&E") (I&E St. 2), Mr. Robert D. Knecht, a witness appearing on behalf of the Office of Small Business Advocate ("OSBA") (OSBA St. 1), and Mr. James L. Crist, a witness appearing on behalf of Pennsylvania State University ("PSU") (PSU St. 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. Have you prepared an exhibit to accompany your rebuttal testimony?

A. Yes. I have prepared an update of my original Exhibit No. 400. In this exhibit, I have updated the Company's cost of debt and provided later data regarding the cost of equity. With these later data, I determined that my original recommendation continues to be valid.

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 proposed cost of debt in this case. Mr. O'Donnell also accepted the Company's proposed cost of debt. Messrs. Knecht and Crist do not comment on the capital structure ratios. The cost of equity has been disputed by each of the witnesses. The equity returns proposed by the I&E, OCA and OSBA witnesses are entirely too low to reflect the risks of CPA and the prospective cost of equity. This is especially apparent with the proposals of the OCA and OSBA.

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 opposing party recommendations 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:

- The impact of the coronavirus pandemic, the collapse of crude oil prices, and the end of the record-setting 128-month economic expansion that occurred in February 2020 that have impacted the cost of equity and have been reflected in the data I used in compiling an update in my analysis.
- Comparable Companies – Mr. Keller has made several deletions to the members of my Gas Group. Mr. O'Donnell has adopted my Gas Group with one addition and has separately analyzed the data for NiSource, Inc. 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.

- Discounted Cash Flow (DCF) – The DCF results proposed by the OCA witness is 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 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.

CAPITAL STRUCTURE

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.

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 the average common equity ratio established in rate case decisions by other state regulators. 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 and substituting a hypothetical capital structure.

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 13), the Company's actual capital structure ratios are fairly comparable to the companies in the comparison group and are therefore entirely reasonable and acceptable. 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 most recently approved common equity ratio by this Commission rather than rely 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. This is the most relevant benchmark common equity ratio for comparative purposes in this case. Indeed, the Company's proposed common equity ratio of 54.19% is entirely reasonable based on prior Commission action. Moreover, the reasonableness of the Company's actual capital structure containing a common equity ratio of 54.19% 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 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 average common equity was 52.23%, with a range from 39.80% to 62.30% (see OCA St. 3 at page 30). This comparison supports the actual 54.19% common equity ratio for CPA. Mr. Keller found that the range of common equity ratios for his Barometer Group was from 33.18% to 53.48% for 2019 and 32.78% to 59.01% for the five-year average (see I&E St. 2 at page 12). Here, the Company's actual common equity ratio falls within that range. Hence, the Company's actual common equity ratio conforms with Commission policy that states that the actual, not hypothetical, common equity ratio will be employed when it falls within the Barometer Group's range.

Q. But, Mr. O'Donnell points out (see page 35 of OCA Statement 3), that when including short-term debt in the comparison, the common equity ratio for your Gas Group is lower. Please explain.

A. Mr. O'Donnell's observation in this regard is not valid for rate case purposes. The common equity ratios that he cites from my Exhibit No. 400 include short-term debt at fiscal/calendar year end. For gas distribution utilities, these amounts are typically near the peak amount for the reporting period. For rate cases, we use our average amount of short-term debt to accommodate the seasonal nature of short-term borrowings. This mismatch of Mr. O'Donnell's observation makes his comparison invalid.

Q. Is Mr. O'Donnell's capital structure proposal consistent with the historic capital structure experience of CPA, shown on Schedule 2 of Exhibit No. 400?

A. No. At pages 35-36, Mr. O'Donnell contends that the capital structure ratio for CPA is without support. However, CPA provided Mr. O'Donnell with data in support of the Company's capital structure ratio. (See Exhibit PRM-1R, attached hereto). This shows the need for additional capital to finance rate base growth, including retained earnings, additional paid in capital, and additional debt. I should note that the Company retains all of its earnings rather than pay dividends to support its pipe replacement program.

Mr. O'Donnell also references NiSource as further support to pull down the common equity ratio. NiSource is not the appropriate focus because it is a holding company and it is not appropriate to compare an operating utility capital structure to a holding company capital structure.

Moreover, Mr. O'Donnell has not substantiated his position regarding the selection of hypothetical capital structure ratios, other than it achieves a lower common equity ratio. 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 altering the debt cost rate for CPA. This results in a serious mismatch of debt ratio and 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.

COST OF LONG-TERM DEBT UPDATE

Q. Have you updated the Company's cost of debt?

A. Page 3 of Schedule 6 of Exhibit No. 400 (Updated), which is attached, provides the Company's cost of debt for the FPFTY. It reflects the actual cost of the new issue of promissory notes that were issued in March 2020. I have carried forward the interest rate from that issue to the planned new issue of Senior Notes in the FPFTY. As shown on page 3 of Schedule 6 of Exhibit No. 400 (Updated) the embedded cost of long-term debt is 4.73% for the FPFTY. This change increased the overall cost of debt by 0.03% (4.73% - 4.70%), from my original proposal. Company witness Miller has adjusted the revenue requirements for this change.

COST OF EQUITY UPDATE

Q. Have you updated your cost of equity analysis for CPA?

A. I have prepared an update of the data that I used to measure the cost of equity for several reasons. With these later data, I have measured the impact of the coronavirus pandemic and the collapse of crude oil prices on my recommendation by looking at recent financial and economic data. This analysis shows that the pandemic has materially increased CPA's cost of common equity.

However, it is my opinion that public utility ratemaking is prospective, and that rates, including the cost of common equity, should reflect conditions during the FPFTY and for the period rates are expected to be in effect. For this reason, I have not altered my recommended cost of equity for CPA in this proceeding even though the updated evidence shows that a higher cost of equity is now warranted.

Q. Have recent events caused you to review the soundness of your recommendation?

A. Yes, but the impact of those events have not changed my recommendation. Extraordinary events around the COVID-19 pandemic have transpired since the preparation of my direct testimony in this case. The market data that I originally used in this case contained information through December 2019. Since that time, there has been significant turmoil that has rocked the stock and bond markets in the February-May 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 we entered a recession in February 2020, a historic rout in stock prices and extraordinary actions by the Federal Open Market Committee ("FOMC") to address these disruptions had a dramatic impact on the capital markets. These actions brought the Fed Funds rate to near zero. How these events are fully resolved is yet to be determined.

Q. Have you considered these changed fundamentals in your cost of equity analysis?

A. Yes. I have considered these events as they impact the inputs that I used in the various models of the cost of equity. Indeed, these impacts should be considered, but only as to their prospective impact during FPFTY and expected rate effective period. Resetting the cost of equity based on the extraordinary and non-recurring conditions that exist today is not appropriate in my view.

However, the Commission may want to examine the effects of the pandemic in making its determination of prospective rates in this proceeding. To do so, I have recalculated my cost of equity models using input data that includes conditions associated with the economic recession. I have accomplished this by using a three-month average period in compiling my later data. I have done this to avoid mixing expansion data with recession market data in my update. In the post expansion period, a 3-month period and current projections are far more representative of what the prospective cost of capital will be during the FPFTY than the data prior to the coronavirus outbreak. I emphasize that I am not departing from my long-standing approach of using six-month data, and I am not changing my recommendation. As shown below, however, if this recent data were used, my recommendation would increase from my original recommendation.

Q. How have the results of the various measures of the cost of equity performed in your additional analysis?

A. Those results are shown on page 2 of Schedule 1 of CPA Exhibit No. 400 (Updated). Other than shifting to a three-month average in the update, all procedures used to apply each of the models of the cost of equity are the same as in my direct testimony. On page 2 of Schedule 1, I have shown the comparison of the updated cost of equity results and the difference in the outcomes from my original analysis contained in Statement No. 8. You will see that the DCF result moved up by a meaningful amount due to the increase in the dividend yield (i.e., 3.39% currently vs 2.69% formerly) and the leverage adjustment. The growth rate that I used in the DCF has not changed so that the later DCF calculation is 1.01% higher than the former one (12.92% - 11.91% = 1.01%). Indeed, the update of the range of earnings per share growth rates is 6.20% to 10.06%, which is not materially different from the original range of 5.94% to 10.06%. Even setting aside the leverage adjustment, the simple dividend yield plus growth return moved from 10.19% originally to 10.89% in the update, or an increase of 0.70%.

The Risk Premium approach shows a downward change in the cost of equity in the update. It should be noted that an increase in the risk premium value provided some offset to the decline in the prospective yield on A-rated public utility debt.

The revised CAPM results of 12.49% show a significant increase in the cost of equity. The increase can be traced to two factors; those being an increase in the beta ("β) measure of systematic risk and an increase in the market premium that is represented by the return on the overall market less the risk-free rate of return ("Rm-Rf"). These increases have been offset by the decline in the risk-free rate of return. That decline was a response to the FOMC that began to reduce the federal funds rate (i.e., the FOMC had indicated 0.25 percentage point reductions to the federal funds rate on July 31, 2019, September 18, 2019, and October 30, 2019), in response to a perceived weakening of the global economy due in part to the U.S.'s trade war with China. The FOMC specifically noted weakness in business fixed investment and exports. Further action was taken by the FOMC to support the money and capital markets during the coronavirus pandemic. This brought the Fed Funds rate to near zero. The risk-free rate of return that I used in the CAPM is based upon the yields on 30-year Treasury bonds, which in my opinion, will be 1.75% on a prospective basis (the July 2020 yield was 1.31%). Along with the decline in the risk-free rate of return, the market premium ("Rm-Rf") has increased, which makes perfect sense because that premium increases with the decline in interest rates. Also noteworthy is the change in the beta. The leverage adjusted betas has increased from 0.83 to 1.05 in my update. Even without the leverage adjustment, the Value Line beta has increased from 0.66 to 0.84. This shows a meaningful increase in the systematic (i.e., market) risk for the Gas Group since my direct testimony was prepared.

Lastly, the Comparable Earnings approach shows a slight decline in results. Those results will be subject to further pressure as the consequences of the current recession become clearer on the prospective returns for these non-regulated companies.

Q. Do you propose any change in your recommended equity return attributed to your update?

A. No. The results of my various models of the cost of equity show some decline (i.e., Risk Premium and Comparable Earnings) or a significant increase in the cost of equity (i.e., DCF and CAPM), as compared to my original study. An average of all differences in model results show an increase in the cost of equity of 0.72%. I continue to support the 10.95% return on equity that includes the increment for management performance.

OPPOSING PARTIES EQUITY PROPOSALS AND RELEVANT MARKET FUNDAMENTALS

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. Further, the Commission should reject the proposal by Mr. O'Donnell to set the Company's return at 8.50%. A cost of equity return of 9.86% as proposed by Mr. Keller, while still inadequate and not fully reflective of more recent market conditions is far more reasonable and shows that not only is Mr. O'Donnell's proposal unreasonable, but that Mr. Knecht's proposal of 7.50% is even more unreasonable. 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. Knecht are much too low to reflect the risk and return for CPA.

Q. How do Mr. Keller's, Mr. O'Donnell's, and Mr. Knecht's recommendations compare

with recently authorized equity returns?

A. The Commission has decided the cost of equity for the Electric Division of UGI Utilities in a rate case decision that established a cost of equity of 9.85%. The business profile of CPA is considered riskier from a financial perspective than electric distribution businesses, so a 9.85% return on equity would be insufficient.

Q. Has the Commission decided the return on equity issue in other, more recent rate cases?

A. Yes. The Commission set the return on equity at 9.54% for Citizen's Electric Company on April 27, 2020 at Docket No. R-2019-3008212, at 9.73% for Valley Energy, Inc. on April 27, 2020 at Docket No. R-2019-3008209, and at 9.31% for Wellsboro Electric Company on April 29, 2020 at Docket No. R-2019-3008208. In each case, the return on equity determination was based primarily on the DCF method, with CAPM providing a comparison result. Since the facts of those cases do not bear directly upon CPA, they do not provide much guidance for resolving the return on equity in this proceeding. But what they do show is the positions of the OCA and OSBA (i.e., 8.50% or 7.50% respectively) are totally inadequate for CPA.

Q. How do Mr. Keller's, Mr. O'Donnell's, and Mr. Knecht recommendations compare with the recently authorized DSIC equity return for gas utilities?

A. They are lower. The Commission has recently set the equity return for the DSIC in its Quarterly Earnings Report (see Docket No. M-2020-3020940 at Public Meeting held August 6, 2020). There, the Commission set the return on equity for the DSIC at 10.10% for gas distribution utilities, which should be considered the floor of returns that should guide the rate of return determination in this case. Indeed, it should be noted that the Commission increased the DSIC return by 0.10% for the gas distribution utilities in its recent decision.

Q. Why would the 10.10% 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, the DSIC return receives a true-up such that the achieved returns on DSIC investments equal the intended return in those proceedings. 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.

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 any of the positions of the OCA or OSBA. 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 OSBA?

A. If the Commission were to follow the proposals of OCA or OSBA, 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. The higher the index the greater the risk. 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. Since April 2020, the VIX has averaged 35.32, which points to high risk in the equity market. The Commission could be guided in deciding the return on equity in this case by looking back to the last time when the VIX was showing high risk. That time would be for the years 2008 and 2009 during the Financial Crisis. The average VIX for 2008 and 2009 was 34.04 and 32.83, respectively. During that time, natural gas distribution utilities nationally were on average granted returns on equity of 10.39% in 2008 rate cases and

10.22% in 2009 rate cases decided during a period of similar market turmoil (see Exhibit PRM-2R). This shows that returns, such as 7.50% or 8.50% are totally inadequate.

Q. At page 40 of OCA Statement No. 3, Mr. O'Donnell observes that regulated ROEs have trended downward over the past 15 years. Please respond.

A. They have. But at the same time the regulatory premiums, i.e., the authorized returns less the corresponding public utility bond yields, have increased. This is shown by the data provided below and shown in Exhibit PRM-2R.

Years	Number of Years	Average Regulatory Risk Premium
1984-2019	36	4.00%
2000-2019	20	4.72%
2010-2019	10	5.41%
2015-2019	5	5.61%

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. 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 risk factors affecting CPA.

PROXY GROUP

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 most of the companies in my Gas Group and inserts UGI Corporation in the Comparison Group, but 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. There is no reason to look at NiSource separately in this case.

Q. Should UGI Corporation be included in the Comparison Group?

A. No. Non-utility operations comprise 87% of revenues, 48% of net income, and 73% of assets for UGI Corporation. This makes UGI Corporation a non-comparable company, because its risk is higher CPA. It should not be included in a Comparison Group for this case.

Q. Mr. Keller used the percentage of revenues devoted to utility operations as a criterion for screening companies to assemble his Barometer Group. Please explain why this is not the correct criterion.

A. For utilities, the percentage of regulated revenues cannot be used to select members of the Barometer Group 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-6:

		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 60% for all members of my Gas Group. As such, these data show that no elimination to my Gas Group is appropriate in this case.

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 certainly 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.[1] The use of multiple methods provides 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.[2]

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.

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[1] The growth rate variables shown on Schedules 8 and 9 of CPA Gas Exhibit No. 400 shows that the assumption associated with the simplified DCF model are not reasonable.

[2] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

A. I used a 7.50% growth rate for my Gas Group. Mr. Keller used 6.52% (the actual growth rate was 7.64%, which Mr. Keller adjusted by excluding the Value Line growth rate estimate for Northwest Natural Gas) for his Barometer Group (see I&E Ex. 2 – Schedule 7) and Mr. O'Donnell used a 4.0% to 6.0% growth rate for his Comparison Group (see OCA Statement No. 2 at page 56).

Q. Do the DCF results utilized by Mr. Keller provide a reasonable representation of the cost of equity?

A. There is an anomaly in one of Mr. Keller's results. The principal purpose of assembling a Barometer Group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the Barometer Group results 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, one of the DCF results presented by Mr. Keller falls into that category:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Northwest Natural Gas	3.25%	+	3.10%	=	6.35%

The reason that the DCF return for Northwest Natural is so low can be traced to Mr. Keller's exclusion of the Value Line forecast for this company. He excluded the one high data point for Northwest Natural Gas, and then retains growth rates from other sources that are much too low. He improperly throws out a high number while retaining unreasonably low numbers for one company. This introduces a bias to his result.

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.	2.47%	+	7.21%	=	9.68%
CPK	Chesapeake Utilities, Inc.	2.16%	+	6.87%	=	9.03%
NI	NiSource, Inc.	3.83%	+	6.87%	=	10.70%
OGS	One Gas, Inc.	3.00%	+	5.67%	=	8.67%
SJI	South Jersey Industries	4.84%	+	10.97%	=	15.81%
SR	Spire, Inc.	3.79%	+	4.96%	=	8.75%
	Average	3.35%	+	7.09%	=	10.44%

Q. At page 24 of I&E Statement No. 2, Mr. Keller excludes the <u>Value Line</u> growth estimate for Northwest Natural from his analysis. Do you agree?

A. No. Mr. Keller says, "Value Line's growth projection for Northwest is extremely inconsistent and would have an unreasonable and unwarranted impact on my DCF analysis." However, Mr. Keller's approach to excluding the Value Line growth rate for Northwest is one-sided. He advocates the exclusion of a high growth rate, but he makes no effort to exclude any low growth rates. There is a clear bias to his exclusion. As I demonstrated above, by altering the growth rate for Northwest Natural, Mr. Keller has made its result an outlier that artificially lowers his overall DCF result. Moreover, the use of a group average without alternation will give appropriate weight to both high and low growth rates, and as such all values (e.g. high and low) should be used in the analysis.

Q. What would be the DCF result if Northwest Natural were treated equal to the other members of Mr. Keller's Barometer Group?

A. Certainly, the DCF return would have been much higher if Mr. Keller had not eliminated the forecast earnings projection by <u>Value Line</u> for Northwest Natural. If he had maintained the <u>Value Line</u> earnings growth for Northwest Natural and averaged it with earnings growth rates from other sources the growth rate would have been 10.90% for this company and the DCF return for Northwest Natural Gas would have been 14.15% (dividend yield of 3.25% plus growth of 10.90%) (see I&E Ex. 2, Schedules 6 and 7). This correction thereby increases the Barometer Group average DCF return to 10.98% (3.34%

+ 7.64%).

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 May 1, 2020 to July 24, 2020 (see OCA ST. 3 at page 45). He arrives at a range of dividend yields of 3.3% to 3.5%. He then adds a growth rate taken from five sources. He employs the use of a "plowback" method, Value Line historical growth rates of earnings, dividend and book value, Value Line forecasts of earnings, dividends and book value growth, and earnings forecast by CFRA and Schwab (see OCA St. 3 at pages 46-56).

Q. At page 56 of OCA Statement No. 3, Mr. O'Donnell claims that it would be inaccurate to use only earnings growth rates in the DCF because the DCF formula is dependent on future dividend growth. Do you agree?

A. No. To mitigate this alleged problem, Mr. O'Donnell presents EPS, DPS, and BPS growth rates. 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. 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.[3] Therefore, his 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 is 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 (plowback), or its surrogate retention 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 10.1% for 2023-2025 (see Exhibit KWO-3) 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., 3.30%

[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

+ 3.5% + 3,5% = 10.3% ÷ 3 = 3.43%)

Return on Equity	10.10%
Dividend Yield on Book Value	-5.80%
Dividend Yield on Market Value	3.43%
Result	7.73%

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 10.10% should be reduced to 7.73%. 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 9.3% by Value Line, 6.7% by CFRA, and 6.7% by Schwab (see Exhibit KWO-1). The average earnings per share growth rate is 7.57% (9.3% + 6.7% + 6.7% = 22.7% ÷ 3). The resulting DCF return is 11.00% (3.43% + 7.57%). This provides a far more reasonable DCF result than the 8.40% (7.3% + 9.5% = 16.8% + 2) midpoint DCF return advocated by Mr. O'Donnell (see OCA St. 3 at page 56). As I describe in my pre-filed direct testimony, forecast earnings growth is the only valid measure of growth for DCF purposes. The theory of DCF indicates that the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share and dividend growth will equal earnings growth with a constant payout ratio. Unfortunately, a constant payout ratio reflects neither the reality of the equity markets or investor expectations. Therefore, to 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 primary emphasis. Indeed, my DCF result, even setting aside the leverage adjustment, is 10.89% (see Schedule 7 of Exhibit No. 400 (Updated)).

COST OF COMMON EQUITY - LEVERAGE ADJUSTMENT

Q. At pages 39-44 of I&E Statement No. 2, Mr. Keller responds to your leverage adjustment and argues that it should be rejected. Do you agree?

A. Among his reasons for opposing the leverage adjustment, Mr. Keller says, the rating agencies use book value in their analysis, it was rejected by the PUC in other cases and "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," which "demonstrates that investors base their decision on book value debt and equity ratios for the regulated utilities," so "no adjustment is needed." As explained above, there is no merit to these arguments of Mr. Keller. In his discussion of my leverage adjustment, Mr. Keller mentions market-to-book ratios ("M/B"). I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio (see I&E St. 2 at page 39). 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 42). 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 42-43). Please comment.

A. Mr. Keller points to several decisions where the Commission declined to make a leverage adjustment – i.e., rate cases including Aqua Pennsylvania, the City of Lancaster Water Department, and UGI – Electric Division (see I&E St. 2 at page 43). 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. Just like 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[4] 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 when arriving at a 9.85% equity return.

Q. Third, Mr. Keller argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

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[4] 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.

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 I&E St. 2 at pages 43-44). 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 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 (Updated). 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 78-80 of OCA Statement No. 3, 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" and is "an attempt to justify an unreasonable return on equity for the Company." 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.

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, (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 unreflecting of the forward-looking prescription of the CAPM that requires use of investor-expected returns.

Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The <u>Blue Chip</u> report dated July 31, 2020 shows this comparison. For the second quarter of 2020, the gap was 0.69% (1.38% - 0.69%) between the yields on 30-year and 10-year Treasury obligations. For the period 2022-2026, that gap is projected at 0.70% (3.0% - 2.3%) as shown by the comparison on page 2 of Schedule 13 of Exhibit No. 400 (Updated). This shows a systematic understatement of Mr. Keller's CAPM returns. 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 10 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 2020 and the first, second and third quarters of 2021 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, 2020. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2021	1.20%	1.80%
2022	1.50%	2.20%
2023	2.10%	2.70%
2024	2.50%	3.10%
2025	2.70%	3.30%
2026	2.90%	3.50%
Average	2.15%	2.77%

The resulting risk-free rate of return is 2.15% using the yield on 10-year Treasury Notes, as compared to Mr. Keller's 1.22%, and 2.77% 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 pages 39 of CPA Statement No. 8). Those results are:

	Rf	+	*β*	(	*Rm*	-	*Rf*	) +	*size*	=	*K*
Barometer Group	2.15%	+	0.82	(	10.35%	-	2.15%	) +	1.02%	=	9.89%

This CAPM result employs the betas (“β) and market return (“Rm”) proposed by Mr. Keller.

Q. At pages 45-46 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. 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 <u>Wong</u> article that Mr. Keller cites provides no support for rejecting the size adjustment. The <u>Wong</u> 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 <u>Wong</u> 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 5.5% and 7.5% (see OCA St. 3 at page 68). This clearly is totally inconsistent with the CAPM that I revised using Mr. Keller's data, the DCF, and the Comparable Earnings 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 OCA St. 3 at page 65). 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% (12.1% - 6.0%) as revealed in the 2020 SBBI Yearbook.[5]

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 4.0% to 6.0%. 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 provides any double-counting for this risk factor (see page 87 of OCA St. 3). A size adjustment is necessary because the financial impact of 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:

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[5] Ibbotson® Stocks, Bonds, Bills and Inflation ("SBBI") 2020 Classic Yearbook (Morningstar): p10-7

> 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.

COST OF COMMON EQUITY – OTHER METHODS

Q. At page 16 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 page 20 of I&E St. 2). And he further asserts that the Comparable Earnings method is too subjective, 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. 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 pages 31-35). 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 89 of OCA Statement No. 3, Mr. O'Donnell disagrees with your Risk Premium results because he believes that the best predictor of future yields are the current yield. 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. What does Mr. Keller say about your Risk Premium analysis?

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 19-20 of I&E St. 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 10.50%, and 10.10% as updated. Hence, my Risk

Premium cost rate is fully responsive to changing market fundamentals.

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.[6]

Q. At page 30 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

[6] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

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.

<u>OSBA and PSU PROPOSALS</u>

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

A. Yes. Mr. Knecht did not submit an independent analysis of the cost of equity. Instead, he opines that the Company's current rates provide a rate of return on common equity of 7.50% that he deems to be reasonable. He bases his proposal using returns previously awarded by the Commission in its rate case decision for the Electric Division of UGI Utilities and the alleged reduction in business risk granted to the Company by the Pennsylvania legislature.

Q. Does his proposal have merit?

A. Absolutely not. First, it is based on the false assumption that the risk premium implicit in the Electric Division of UGI Utilities rate case is static. As I have clearly demonstrated in my direct testimony, the risk premium is dynamic, in that it decreases as interest rates rise and increases as interest rates fall. As Mr. Knecht has indicated, interest rates have declined since the time of the UGI Utilities Electric Division rate case (see page 5 of OSBA St. 1). Hence, the risk premium today is higher when viewed in the context of dramatically lower interest rates.

Q. Mr. Knecht also opines that the anecdotal evidence suggests that utility risk is decreasing and that can be traced to the variety of rate mechanisms provided by

the Pennsylvania legislature (see footnote 4 of OSBA Statement No. 1). Is his assessment valid?

A. No. Many of the mechanisms listed by Mr. Knecht are already in place for many of the companies that comprise my Gas Group. Hence, whatever risk reducing attributes of these mechanisms, they are encompassed in the market derived cost equity results that I have reflected in my cost of equity recommendation. This is because investors are aware of these mechanisms and have incorporated them into the prices they set for the common stocks of these companies. To further adjust the cost of equity for these factors, as Mr. Knecht proposes, would double-count for the risk implications of these mechanisms. I also note that some of these mechanisms, such as the distribution system improvement charge and the fully projected future test year are designed to encourage significant expansion of plant improvements and that such expansion increases risk for utilities. Finally, while available to all Pennsylvania utilities, some of these mechanisms have not been implemented by CPA, e.g., rate decoupling. Hence, Mr. Knecht's proposal is inappropriate for CPA in this case.

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 pages 7 and 8 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.

COST OF COMMON EQUITY - COMPANY SPECIFIC FACTORS

Q. At page 32 of I&E Statement No. 2, Mr. Keller asserts that the "switching cost to move from one NGDC to another," will discourage customers from changing to another gas utility. Is this correct?

A. Only in part. The situation of overlapping service territories is unique to gas utilities operating in western Pennsylvania. Other than NiSource, who is the parent company of CPA, no other member of my Gas Group is faced with overlapping service territories that provide the opportunity of bypass from another utility. Hence, the risk faced by CPA is generally higher than most members of my Gas Group.

Q. Please refer to Mr. Keller's discussion (see pages 34-39) concerning the potential loss of the Company's WNA.

A. Mr. Keller seems to believe that the availability, or lack thereof, of the WNA will not affect the Company's risk. He is wrong in both regards. Loss of the WNA would materially increase the risk of CPA. Without the WNA or RNA, a return above that shown by the Gas Group would be required for CPA.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Keller, Mr. O'Donnell, and Mr. Knecht 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. Given the company-specific risk factors including CPA's operating risk, an opportunity to earn a cost of equity of 10.95%, inclusive of 20 basis points to recognize the effectiveness of the Company's management, is reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 3

Question No. OCA 3-015:

Please provide the CGP capital structure and associated embedded cost rates and tax gross-up factors for FY 2018, FY 2019 as well as each succeeding quarter post-FY 2019.

Response:

Please refer to OCA 3-015 Attachment A to this response.

December 2018

	Amount in Millions [1]	Percentage of Total [1]	Effective Cost Rates
Long Term Debt	705.5	42.82%	5.14% [2]
Short Term Debt	55.9	3.39%	2.42% [2]
Common Equity	886.4	53.79%	11.39% [3]
	1,647.8	100.00%	

December 2019

	Amount in Millions [1]	Percentage of Total [1]	Effective Cost Rates
Long Term Debt	785.5	42.84%	4.99% [2]
Short Term Debt	64.5	3.52%	2.46% [2]
Common Equity	983.4	53.64%	9.21% [3]
	1,833.4	100.00%	

March 2020

	Amount in Millions [1]	Percentage of Total [1]	Effective Cost Rates
Long Term Debt	895.5	43.02%	4.86% [2]
Short Term Debt	76.5	3.67%	2.30% [2]
Common Equity	1,109.9	53.31%	8.42% [3]
	2,081.9	100.00%	

[1] Reported in Schedule E of the Quarterly Earnings Report filed with the Commission.

[2] Reported in Schedule F of the Quarterly Earnings Report filed with the Commission.

3 Reported in Schedule D-1 of the Quarterly Earnings Report filed with the Commission. Schedule D-1 includes a income tax rate of 28.89% in the calculation to present the return on common equity including the tax effect of using debt costs.

Year	Gas Average Authorized ROE	A-rated Utility Bond Yields	Gas Equity Risk Premium
1984	15.31%	14.03%	1.28%
1985	14.75%	12.47%	2.28%
1986	13.46%	9.58%	3.88%
1987	12.74%	10.10%	2.64%
1988	12.85%	10.49%	2.36%
1989	12.88%	9.77%	3.11%
1990	12.68%	9.86%	2.82%
1991	12.45%	9.36%	3.09%
1992	12.02%	8.69%	3.33%
1993	11.37%	7.59%	3.78%
1994	11.24%	8.31%	2.93%
1995	11.44%	7.89%	3.55%
1996	11.12%	7.75%	3.37%
1997	11.30%	7.60%	3.70%
1998	11.51%	7.04%	4.47%
1999	10.74%	7.62%	3.12%
2000	11.34%	8.24%	3.10%
2001	10.96%	7.76%	3.20%
2002	11.17%	7.37%	3.80%
2003	10.99%	6.58%	4.41%
2004	10.63%	6.16%	4.47%
2005	10.41%	5.65%	4.76%
2006	10.40%	6.07%	4.33%
2007	10.22%	6.07%	4.15%
2008	10.39%	6.53%	3.86%
2009	10.22%	6.04%	4.18%
2010	10.15%	5.46%	4.69%
2011	9.92%	5.04%	4.88%
2012	9.94%	4.13%	5.81%
2013	9.68%	4.48%	5.20%
2014	9.78%	4.28%	5.50%
2015	9.60%	4.12%	5.48%
2016	9.54%	3.93%	5.61%
2017	9.72%	4.00%	5.72%
2018	9.59%	4.25%	5.34%
2019	9.68%	3.77%	5.91%
Averages:			
1984-2019			4.00%
2000-2019			4.72%
2010-2019			5.41%
2015-2019			5.61%

Exhibit No. 400
(Updated)

COLUMBIA GAS OF PENNSYLVANIA, INC.

Schedules to Accompany

The Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

and

Fair Rate of Return

August 26, 2020

COLUMBIA GAS OF PENNSYLVANIA, INC.
Index of Schedules

Columbia Gas of Pennsylvania, Inc.
Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.22%	4.73%	2.00%
Short Term Debt	3.59%	2.06%	0.07%
Total Debt	45.81%		2.07%
Common Equity	54.19%	10.95%	5.93%
Total	100.00%		8.00%

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 (10.41% ÷ 2.07%)	5.03 x
Post-tax coverage of interest expense (8.00% ÷ 2.07%)	3.86 x

Columbia Gas of Pennsylvania, Inc.
Cost of Equity
as of July 31, 2020

									July 31, 2020 Three-Month Average	December 31, 2019 Six-Month Average	Difference
Discounted Cash Flow (DCF)			***D_1/P_0*** [1]	**+**	***g*** [2]	**+**	***lev.*** [3]	**=**	***k***		
Gas Group			3.39%	+	7.50%	+	2.03%	=	12.92%	11.91%	1.01%
Risk Premium (RP)					***I*** [4]	**+**	***RP*** [5]	=	***k***		
Gas Group					3.35%	+	6.75%	=	10.10%	10.50%	-0.40%
Capital Asset Pricing Model (CAPM)	***Rf*** [6]	**+**	***ß*** [7]	***x (***	***Rm-Rf*** [8]	***) +***	***size*** [9]	**=**	***k***		
Gas Group	1.75%	+	1.05	x (	9.26%	) +	1.02%	=	12.49%	10.19%	2.30%
Comparable Earnings (CE) [10]					***Historical***		***Forecast***		***Average***		
Comparable Earnings Group					12.8%		12.6%		12.70%	12.75%	-0.05%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) A-rated public utility bond yield comprised of a 1.75% risk-free rate of return (Schedule 13 page 2) and a yield spread of 1.60% (Schedule 11 page 3)
(5) Schedule 12 page 1
(6) Schedule 13 page 2
(7) Schedule 10
(8) Schedule 13 page 2
(9) Schedule 13 page 3
(10) Schedule 14 page 2

Columbia Gas of Pennsylvania, Inc.
Capitalization and Financial Statistics
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,768.9	$ 1,591.9	$ 1,361.1	$ 1,210.3	$ 1,098.5	
Short-Term Debt	$ 46.5	$ 51.5	$ 37.8	$ 33.4	$ 27.8	
Total Capital	$ 1,815.5	$ 1,643.4	$ 1,398.9	$ 1,243.7	$ 1,126.3	
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	44.4%	44.3%	46.0%	44.7%	45.1%	44.9%
Common Equity [1]	55.6%	55.7%	54.0%	55.3%	54.9%	55.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	45.8%	46.1%	47.4%	46.1%	46.5%	46.4%
Common Equity [1]	54.2%	53.9%	52.6%	53.9%	53.5%	53.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [1]	10.4%	13.0%	9.4%	10.5%	11.3%	10.9%
Operating Ratio [2]	72.9%	72.9%	76.3%	73.3%	76.3%	74.3%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	4.18 x	4.52 x	4.21 x	4.63 x	4.75 x	4.46 x
Post-tax: All Interest Charges	3.48 x	3.96 x	3.01 x	3.28 x	3.37 x	3.42 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	4.16 x	4.49 x	4.18 x	4.61 x	4.73 x	4.43 x
Post-tax: All Interest Charges	3.46 x	3.93 x	2.99 x	3.26 x	3.35 x	3.40 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	1.0%	0.8%	1.1%	1.0%	0.7%	0.9%
Effective Income Tax Rate	21.9%	15.9%	37.2%	37.1%	36.8%	29.8%
Internal Cash Generation/Construction [4]	56.8%	66.1%	59.5%	66.7%	73.5%	64.5%
Gross Cash Flow/ Avg. Total Debt [5]	22.6%	23.9%	25.4%	28.4%	29.5%	26.0%
Gross Cash Flow Interest Coverage [6]	4.61 x	4.75 x	4.82 x	5.32 x	5.25 x	4.95 x

See Page 2 for Notes.

Columbia Gas of Pennsylvania, Inc.
Capitalization and Financial Statistics
2015-2019, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Company provided Financial Statements

Gas Group
Capitalization and Financial Statistics [1]
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 5,169.4	$ 4,698.4	$ 4,133.8	$ 3,746.8	$ 3,522.8	
Short-Term Debt	$ 553.3	$ 499.2	$ 402.2	$ 393.6	$ 259.5	
Total Capital	$ 5,722.7	$ 5,197.6	$ 4,536.0	$ 4,140.4	$ 3,782.3	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	26 x	20 x	22 x	22 x	19 x	22 x
Market/Book Ratio	222.4%	217.6%	224.2%	201.9%	187.7%	210.8%
Dividend Yield	2.7%	2.8%	2.6%	2.8%	3.0%	2.8%
Dividend Payout Ratio	72.5%	52.4%	71.1%	60.7%	67.7%	64.9%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	48.3%	47.9%	47.1%	45.0%	45.9%	46.8%
Preferred Stock	1.5%	1.0%	0.0%	0.1%	0.0%	0.5%
Common Equity [2]	50.3%	51.1%	52.9%	54.9%	54.0%	52.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.4%	53.4%	53.0%	50.5%	51.3%	52.3%
Preferred Stock	1.3%	0.9%	0.0%	0.1%	0.0%	0.5%
Common Equity [2]	45.3%	45.7%	47.0%	49.5%	48.7%	47.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	8.6%	10.0%	8.0%	9.2%	9.4%	9.0%
Operating Ratio [3]	83.6%	84.6%	84.1%	83.0%	85.0%	84.1%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.79 x	3.65 x	4.22 x	4.88 x	4.85 x	4.28 x
Post-tax: All Interest Charges	3.37 x	3.47 x	3.31 x	3.58 x	3.62 x	3.47 x
Overall Coverage: All Int. & Pfd. Div.	3.33 x	3.47 x	3.31 x	3.58 x	3.62 x	3.46 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.73 x	3.60 x	4.19 x	4.82 x	4.79 x	4.23 x
Post-tax: All Interest Charges	3.30 x	3.42 x	3.27 x	3.52 x	3.57 x	3.42 x
Overall Coverage: All Int. & Pfd. Div.	3.26 x	3.42 x	3.27 x	3.52 x	3.57 x	3.41 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.0%	3.2%	-5.2%	2.3%	2.4%	1.1%
Effective Income Tax Rate	15.0%	15.6%	39.7%	33.6%	32.6%	27.3%
Internal Cash Generation/Construction [5]	48.7%	46.7%	59.5%	71.6%	71.0%	59.5%
Gross Cash Flow/ Avg. Total Debt [6]	18.3%	18.4%	21.4%	23.7%	22.8%	20.9%
Gross Cash Flow Interest Coverage [7]	6.24 x	6.05 x	6.69 x	7.35 x	6.96 x	6.66 x
Common Dividend Coverage [8]	3.86 x	3.63 x	4.21 x	4.60 x	4.48 x	4.16 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2015-2019, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group "Natural Gas Utility," they are not currently the target of a publicly-announced merger or acquisition, and after eliminating UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
ATO	Atmos Energy Corp.	A1	A	NYSE	0.80
CPK	Chesapeake Utilities Corp.	NAIC "1"		NYSE	0.75
NJR	New Jersey Resources Corp.	A1	BBB+	NYSE	0.90
NI	NiSource Inc.	Baa2	BBB+	NYSE	0.85
NWN	Northwest Natural Holding Compa	Baa1	A+	NYSE	0.80
OGS	ONE Gas, Inc.	A2	A	NYSE	0.80
SJI	South Jersey Industries, Inc.	A3	BBB	NYSE	0.95
SWX	Southwest Gas Holdings, Inc.	A3	A-	NYSE	0.90
SR	Spire, Inc.	A1	A-	NYSE	0.80
	Average	A2	A-		0.84

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics (1)
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 36,567.1	$ 32,871.6	$ 30,827.6	$ 29,173.1	$ 26,655.9	
Short-Term Debt	$ 1,221.9	$ 1,420.3	$ 1,076.1	$ 1,032.2	$ 875.5	
Total Capital	$ 37,789.0	$ 34,291.9	$ 31,903.7	$ 30,205.3	$ 27,531.4	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	20 x	21 x	21 x	21 x	18 x	20 x
Market/Book Ratio	220.8%	204.7%	214.4%	196.0%	181.1%	203.4%
Dividend Yield	3.2%	3.5%	3.3%	3.5%	3.6%	3.4%
Dividend Payout Ratio	62.7%	71.7%	74.4%	74.6%	68.8%	70.4%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.7%	55.0%	56.8%	56.6%	54.7%	55.9%
Preferred Stock	2.2%	2.5%	1.4%	1.9%	1.6%	1.9%
Common Equity (2)	41.1%	42.5%	41.8%	41.6%	43.8%	42.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.2%	57.0%	58.4%	58.2%	56.1%	57.6%
Preferred Stock	2.1%	2.4%	1.4%	1.8%	1.5%	1.8%
Common Equity (2)	39.7%	40.7%	40.3%	40.1%	42.4%	40.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (2)	10.3%	10.3%	10.8%	9.7%	9.7%	10.2%
Operating Ratio (3)	79.3%	79.8%	77.0%	78.2%	79.7%	78.8%
Coverage incl. AFUDC (4)						
Pre-tax: All Interest Charges	3.05 x	2.94 x	3.42 x	3.38 x	3.80 x	3.32 x
Post-tax: All Interest Charges	3.10 x	2.59 x	2.86 x	2.55 x	2.79 x	2.78 x
Overall Coverage: All Int. & Pfd. Div.	3.04 x	2.55 x	2.84 x	2.52 x	2.75 x	2.74 x
Coverage excl. AFUDC (4)						
Pre-tax: All Interest Charges	2.95 x	2.84 x	3.31 x	3.28 x	3.70 x	3.22 x
Post-tax: All Interest Charges	3.00 x	2.48 x	2.75 x	2.44 x	2.69 x	2.67 x
Overall Coverage: All Int. & Pfd. Div.	2.94 x	2.44 x	2.73 x	2.41 x	2.65 x	2.63 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	5.8%	7.3%	7.3%	6.5%	5.5%	6.5%
Effective Income Tax Rate	12.2%	19.0%	28.2%	29.0%	32.5%	24.2%
Internal Cash Generation/Construction (5)	66.0%	75.7%	78.7%	78.0%	71.9%	74.1%
Gross Cash Flow/ Avg. Total Debt (6)	17.5%	17.4%	19.9%	20.5%	20.0%	19.1%
Gross Cash Flow Interest Coverage (7)	4.97 x	4.98 x	5.57 x	5.54 x	5.41 x	5.29 x
Common Dividend Coverage (8)	5.56 x	4.80 x	4.33 x	4.31 x	4.24 x	4.65 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2015-2019, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities

	Ticker	Credit Rating (1) Moody's	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.60
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.55
American Electric Power	AEP	Baa1	A-	NYSE	0.55
American Water Works	AWK	Baa1	A	NYSE	0.55
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	0.80
CMS Energy	CMS	A3	A-	NYSE	0.50
Consolidated Edison	ED	Baa1	A-	NYSE	0.45
Dominion Energy	D	A2	BBB+	NYSE	0.55
DTE Energy Co.	DTE	A2	A-	NYSE	0.55
Duke Energy	DUK	A1	A-	NYSE	0.50
Edison Int'l	EIX	Baa2	BBB	NYSE	0.55
Entergy Corp.	ETR	Baa1	A-	NYSE	0.60
Evergy, Inc.	EVRG	Baa1	A	NYSE	NMF
Eversource	ES	A3	A	NYSE	0.55
Exelon Corp.	EXC	A3	BBB+	NYSE	0.65
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	0.65
NextEra Energy Inc.	NEE	A1	A	NYSE	0.55
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.55
NRG Energy Inc.	NRG	Ba1	BB	NYSE	1.25
Pinnacle West Capital	PNW	A2	A-	NYSE	0.50
PPL Corp.	PPL	A3	A-	NYSE	0.70
Public Serv. Enterprise Inc.	PEG	A2	A-	NYSE	0.65
Sempra Energy	SRE	Baa1	BBB+	NYSE	0.70
Southern Co.	SO	Baa1	A-	NYSE	0.50
WEC Energy Corp.	WEC	A2	A-	NYSE	0.50
Xcel Energy Inc	XEL	A2	A-	NYSE	0.50
Average for S&P Utilities		A3	A-		0.60

Note: (1) Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Columbia Gas of Pennsylvania, Inc.
Investor-provided Capitalization
Actual at November 30, 2019, Estimated at November 30, 2020, and Estimated at December 31, 2021

	Actual at November 30, 2019		Estimated at November 30, 2020		Estimated at December 31, 2021	
	Amount Outstanding	Ratios	Amount Outstanding	Ratios	Amount Outstanding	Ratios
Long Term Debt	$ 785,515,000	43.74%	$ 895,515,000	43.00%	$ 975,515,000	42.22%
Common Stock Equity						
Common Stock	45,128,000		45,128,000		45,128,000	
Additional Paid in Capital	52,889,827		107,889,827		107,889,827	
Retained Earnings	853,475,761		950,868,301		1,099,269,678	
Total Common Equity	951,493,588	52.99%	1,103,886,128	53.00%	1,252,287,505	54.19%
Total Permanent Capital	$1,737,008,588	96.73%	$1,999,401,128	96.00%	$2,227,802,505	96.41%
Short Term Debt (Twelve month average)	58,764,658	3.27%	83,375,269	4.00%	82,945,831	3.59%
Total Capital Employed	$1,795,773,246	100.00%	$2,082,776,397	100.00%	$2,310,748,336	100.00%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.

Long-term Debt Outstanding

Actual at November 30, 2019

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	
November 1, 2006	6.015%	20,000,000	1,203,000	
December 14, 2007	6.865%	58,000,000	3,981,700	
December 16, 2010	6.020%	28,000,000	1,685,600	
March 28, 2012	5.355%	30,000,000	1,606,500	
March 28, 2012	5.890%	35,000,000	2,061,500	
November 28, 2012	5.260%	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	
Total Long-Term Debt		785,515,000	39,219,688	4.99%
Short Term Debt (Twelve month average)	2.17%	58,764,658	1,275,193	
Total Debt		$ 844,279,658	$ 40,494,881	4.80%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Estimated at November 30, 2020

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	
November 1, 2006	6.015%	20,000,000	1,203,000	
December 14, 2007	6.865%	58,000,000	3,981,700	
December 16, 2010	6.020%	28,000,000	1,685,600	
March 28, 2012	5.355%	30,000,000	1,606,500	
March 28, 2012	5.890%	35,000,000	2,061,500	
November 28, 2012	5.260%	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	
Total Long-Term Debt		895,515,000	43,478,448	4.86%
Short Term Debt (Twelve month average)	2.00%	83,375,269	1,667,505	
Total Debt		$ 978,890,269	$ 45,145,953	4.61%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Estimated at December 30, 2021

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	3.8716%	100,000,000	3,871,600	
Total Long-Term Debt		975,515,000	46,147,048	4.73%
Short Term Debt (Twelve month average)	2.06%	82,945,831	1,708,684	
Total Debt		$ 1,058,460,831	$ 47,855,732	4.52%

Source of information: Company provided data

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending July 2020

Company	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	1.91%	1.85%	2.05%	2.15%	2.06%	1.97%	2.23%	2.32%	2.27%	2.24%	2.32%	2.18%			
Chesapeake Utilities Corp (CPK)	1.72%	1.70%	1.71%	1.78%	1.69%	1.69%	1.90%	1.89%	2.01%	1.96%	2.10%	2.09%			
New Jersey Resources Corporation (NJR)	2.75%	2.77%	2.88%	2.96%	2.81%	3.04%	3.57%	3.69%	3.72%	3.59%	3.83%	4.05%			
NiSource Inc (NI)	2.71%	2.69%	2.85%	3.03%	2.89%	2.86%	3.11%	3.38%	3.37%	3.54%	3.72%	3.44%			
Northwest Natural Holding Company (NWN)	2.67%	2.68%	2.75%	2.78%	2.60%	2.60%	2.91%	3.11%	2.93%	2.99%	3.44%	3.57%			
ONE Gas Inc (OGS)	2.19%	2.09%	2.16%	2.25%	2.14%	2.30%	2.63%	2.59%	2.72%	2.58%	2.81%	2.87%			
South Jersey Industries Inc (SJI)	3.59%	3.50%	3.69%	3.81%	3.59%	3.85%	4.41%	4.73%	4.15%	4.20%	4.73%	5.09%			
Southwest Gas Holdings Inc (SWX)	2.39%	2.40%	2.51%	2.88%	2.88%	2.91%	3.38%	3.15%	3.03%	3.01%	3.32%	3.30%			
Spire Inc. (SR)	2.81%	2.72%	2.97%	3.24%	2.99%	2.97%	3.34%	3.35%	3.43%	3.44%	3.80%	4.06%			
Average	**2.53%**	**2.49%**	**2.62%**	**2.76%**	**2.63%**	**2.69%**	**3.05%**	**3.13%**	**3.07%**	**3.06%**	**3.34%**	**3.41%**	**2.90%**	**3.18%**	**3.27%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://performance.morningstar.com/stock/performance-return

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	$$K = \frac{D_o(1+g)^o + D_o(1+g)^o + D_o(1+g)^1 + D_o(1+g)^1}{P_o} + g$$
	3.27%	1.037500	3.39%	
Discrete	D_0/P_0	Adj.	D_1/P_0	$$K = \frac{D_o(1+g)^{.25} + D_o(1+g)^{.50} + D_o(1+g)^{.75} + D_o(1+g)^{1.00}}{P_o} + g$$
	3.27%	1.046451	3.42%	
Quarterly	D_0/P_0	Adj.	D_1/P_0	$$K = \left[\left(1 + \frac{D_o(1+g)^{.25}}{P_o}\right)^4 - 1\right] + g$$
	0.8175%	1.018245	3.37%	
Average			3.39%	
Growth rate			7.50%	
K			10.89%	

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Gas Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
Atmos Energy Corp (ATO)	9.50%	7.50%	6.50%	4.00%	8.50%	6.50%	7.00%	5.50%
Chesapeake Utilities Corp (CPK)	8.00%	9.00%	6.50%	5.50%	10.50%	9.50%	7.00%	10.00%
New Jersey Resources Corporation (NJR)	6.00%	7.00%	6.50%	7.00%	8.50%	7.00%	7.50%	7.50%
NiSource Inc (NI)	-8.00%	-1.00%	-5.00%	-2.00%	-7.00%	-3.00%	-5.00%	-2.00%
Northwest Natural Holding Company (NWN)	-17.00%	-11.00%	0.50%	2.00%	-0.50%	1.50%	-5.50%	-3.00%
ONE Gas Inc (OGS)	9.50%	-	17.00%	-	2.50%	-	7.00%	-
South Jersey Industries Inc (SJI)	-2.50%	1.50%	6.00%	8.00%	6.00%	6.50%	3.50%	5.00%
Southwest Gas Holdings Inc (SWX)	4.50%	8.00%	9.50%	8.50%	6.50%	6.00%	1.50%	4.00%
Spire Inc. (SR)	9.50%	3.50%	5.50%	4.00%	7.00%	7.00%	13.00%	5.50%
Average	2.17%	3.06%	5.89%	4.63%	4.67%	5.13%	4.00%	4.06%

Source of Information: Value Line Investment Survey, May 29, 2020

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

			Value Line				
Gas Group	**I/B/E/S First Call**	**Zacks**	**Earnings Per Share**	**Dividends Per Share**	**Book Value Per Share**	**Cash Flow Per Share**	**Percent Retained to Common Equity**
Atmos Energy Corp (ATO)	7.15%	7.20%	7.00%	7.50%	7.50%	5.50%	4.50%
Chesapeake Utilities Corp (CPK)	4.74%	NA	9.00%	8.50%	10.00%	8.50%	5.50%
New Jersey Resources Corporatior	6.00%	6.00%	2.00%	6.00%	8.50%	2.00%	3.00%
NiSource Inc (NI)	3.49%	5.30%	13.50%	7.50%	5.00%	8.00%	4.50%
Northwest Natural Holding Compar	3.90%	3.90%	26.50%	0.50%	2.00%	9.00%	5.00%
ONE Gas Inc (OGS)	5.00%	5.50%	6.50%	7.50%	4.00%	6.50%	4.00%
South Jersey Industries Inc (SJI)	10.30%	10.30%	12.50%	3.50%	5.50%	6.00%	5.50%
Southwest Gas Holdings Inc (SWX)	8.20%	6.00%	8.00%	4.00%	6.00%	7.00%	5.50%
Spire Inc. (SR)	4.67%	4.80%	5.50%	5.00%	8.50%	5.50%	3.00%
Average	5.94%	6.13%	10.06%	5.56%	6.33%	6.44%	4.50%

Source of Information : Yahoo Finance, Jume 30, 2020
Zacks, Jume 30, 2020
Value Line Investment Survey, May 29, 2020

Gas Group
Financial Risk Adjustment

		ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year		09/30/19	12/31/19	09/30/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	09/30/19	
Capitalization at Fair Values											
	Debt(D)	4,216,249	505,000	1,568,864	8,764,400	957,268	1,500,000	2,730,000	2,672,077	2,373,400	2,809,695
	Preferred(P)	0	0	0	0	0	0	0	0	0	0
	Equity(E)	13,349,252	1,571,974	3,913,860	10,638,657	2,246,701	4,937,853	3,047,159	4,178,915	4,246,604	5,347,886
	Total	17,565,501	2,076,974	5,482,724	19,403,057	3,203,969	6,437,853	5,777,159	6,850,992	6,620,004	8,157,581
Capital Structure Ratios											
	Debt(D)	24.00%	24.31%	28.61%	45.17%	29.88%	23.30%	47.26%	39.00%	35.85%	33.04%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Equity(E)	76.00%	75.69%	71.39%	54.83%	70.12%	76.70%	52.74%	61.00%	64.15%	66.96%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock											
	Issued	119,338.925	16,403.776	89,998.788	382,135.680	30,472.000	52,771.749	92,394.155	55,007.433	50,973.515	
	Treasury	0.000	0.000	2,185.013	0.000	0.000	0.000	0.000	0.000	0.000	
	Outstanding	119,338.925	16,403.776	87,813.775	382,135.680	30,472.000	52,771.749	92,394.155	55,007.433	50,973.515	
	Market Price	$111.86	$95.83	$44.57	$27.84	$73.73	$93.57	$32.98	$75.97	$83.31	
Capitalization at Carrying Amounts											
	Debt(D)	3,560,000	486,600	1,442,845	7,869,600	881,064	1,300,000	2,540,000	2,463,994	2,122,600	2,518,523
	Preferred(P)	0	0	0	0	0	0	0	0	0	0
	Equity(E)	5,750,223	561,577	1,551,717	5,986,700	865,999	2,129,390	1,423,785	2,505,914	2,543,000	2,590,923
	Total	9,310,223	1,048,177	2,994,562	13,856,300	1,747,063	3,429,390	3,963,785	4,969,908	4,665,600	5,109,445
Capital Structure Ratios											
	Debt(D)	38.24%	46.42%	48.18%	56.79%	50.43%	37.91%	64.08%	49.58%	45.49%	48.57%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Equity(E)	61.76%	53.58%	51.82%	43.21%	49.57%	62.09%	35.92%	50.42%	54.51%	51.43%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.80	0.75	0.90	0.85	0.80	0.80	0.95	0.90	0.80	0.84

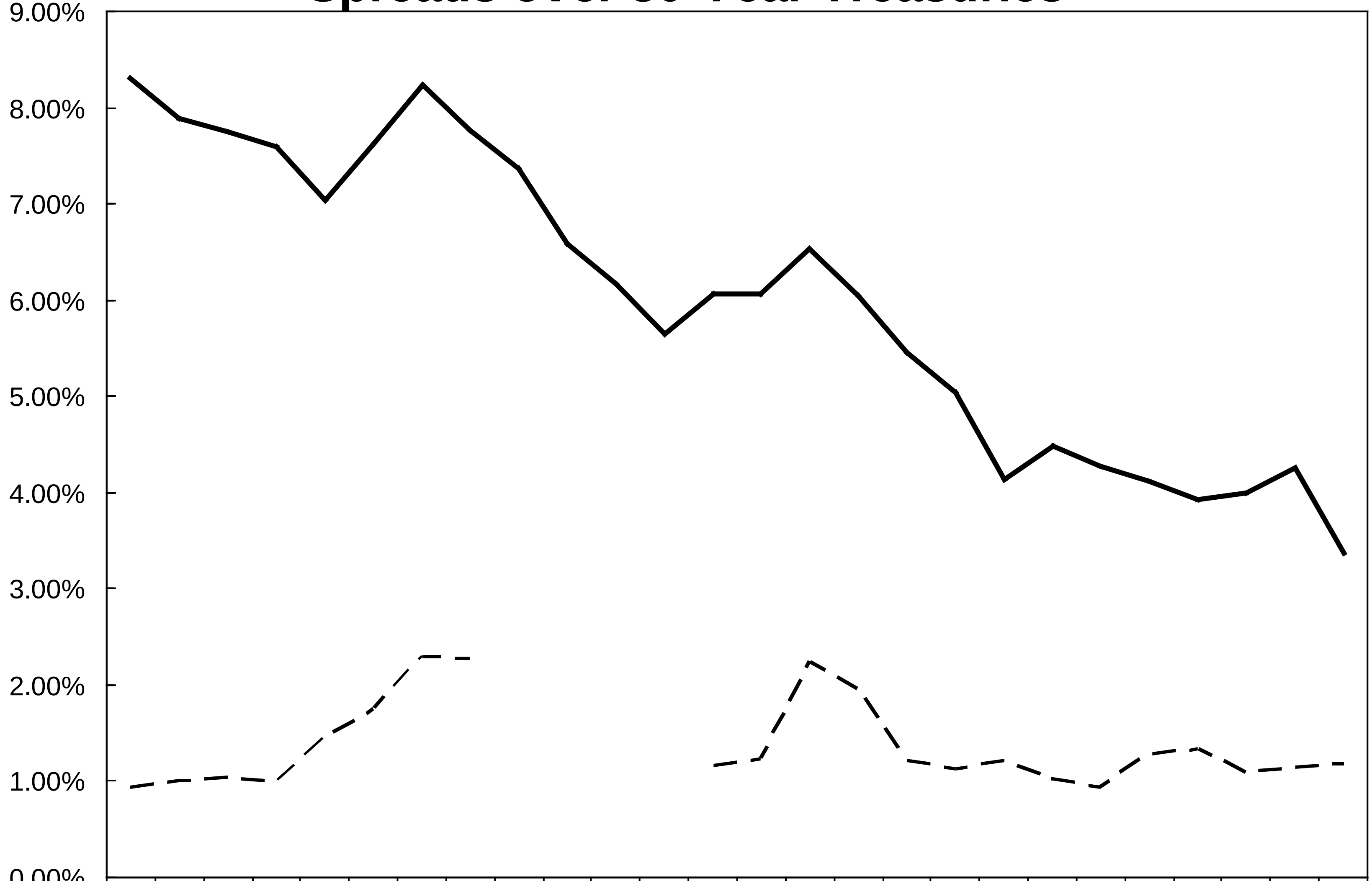
Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.84	=	Bu	[1+	(1-0.21)	0.4934	+	0.0000	]
	0.84	=	Bu	[1+	0.79	0.4934	+	0.0000	]
	0.84	=	Bu	1.3898					
	0.60	=	Bu						
Hamada	Bl	=	0.60	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.60	[1+	0.79	0.9443	+	0.0000	]
	Bl	=	0.60	1.7460					
	Bl	=	1.05						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	-	d	)	P	/	E
	8.67%	=	10.89%	-	(((	8.67%	-	2.98%	)	0.79	)	33.04%	/	66.96%	-	8.67%	-	5.68%	)	0.00%	/	66.96%
	8.67%	=	10.89%	-	(((	5.69%			)	0.79	)	0.4934			-	2.99%			)	0.0000		
	8.67%	=	10.89%	-	((	4.50%					)	0.4934			-	2.99%			)	0		
	8.67%	=	10.89%	-		2.22%									-	0.00%						
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	-	d	)	P	/	E
	12.92%	=	8.67%	+	(((	8.67%	-	2.98%	)	0.79	)	48.57%	/	51.43%	+	8.67%	-	5.68%	)	0.00%	/	51.43%
	12.92%	=	8.67%	+	(((	5.69%			)	0.79	)	0.9443			+	2.99%			)	0.0000		
	12.92%	=	8.67%	+	((	4.50%					)	0.9443			+	2.99%			)	0		
	12.92%	=	8.67%	+		4.25%									+	0.00%						

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2015-2019
and the Twelve Months Ended July 2020

Years	Aa Rated	A Rated	Baa Rated	Average
2015	4.00%	4.12%	5.03%	4.38%
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
Five-Year Average	3.85%	4.01%	4.59%	4.15%
Months				
Aug-20	3.17%	3.29%	3.63%	3.36%
Sep-20	3.24%	3.37%	3.71%	3.44%
Oct-20	3.24%	3.39%	3.72%	3.45%
Nov-20	3.25%	3.43%	3.76%	3.48%
Dec-20	3.22%	3.40%	3.73%	3.45%
Jan-20	3.12%	3.29%	3.60%	3.34%
Feb-20	2.96%	3.11%	3.42%	3.16%
Mar-20	3.30%	3.50%	3.96%	3.59%
Apr-20	2.93%	3.19%	3.82%	3.31%
May-20	2.89%	3.14%	3.63%	3.22%
Jun-20	2.80%	3.07%	3.44%	3.10%
Jul-20	2.46%	2.74%	3.09%	2.77%
Twelve-Month Average	3.05%	3.24%	3.63%	3.31%
Six-Month Average	2.89%	3.13%	3.56%	3.19%
Three-Month Average	2.72%	2.98%	3.39%	3.03%

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.37
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.34	1.10	1.14	1.19

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Average:	12-months		1.40%
	6-months		1.65%
	3-months		1.59%

Common Equity Risk Premiums
Years 1926-2019

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	11.92%	5.22%	6.70%	2.88%
Average Across All Interest Rates	12.09%	6.40%	5.69%	4.99%
High Interest Rates	12.26%	7.57%	4.69%	7.09%

Source of Information: 2020 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2015-2019
and the Twelve Months Ended July 2020

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2015	0.32%	0.69%	1.03%	1.53%	1.89%	2.14%	2.55%	2.84%
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
Five-Year Average	1.30%	1.49%	1.64%	1.90%	2.12%	2.27%	2.57%	2.81%
Months								
Aug-19	1.77%	1.57%	1.51%	1.49%	1.55%	1.63%	1.91%	2.12%
Sep-19	1.80%	1.65%	1.59%	1.57%	1.64%	1.70%	1.97%	2.16%
Oct-19	1.61%	1.55%	1.53%	1.53%	1.62%	1.71%	2.00%	2.19%
Nov-19	1.57%	1.61%	1.61%	1.64%	1.74%	1.81%	2.13%	2.28%
Dec-19	1.55%	1.61%	1.63%	1.68%	1.79%	1.86%	2.16%	2.30%
Jan-20	1.53%	1.52%	1.52%	1.56%	1.67%	1.76%	2.07%	2.22%
Feb-20	1.41%	1.33%	1.31%	1.32%	1.42%	1.50%	1.81%	1.97%
Mar-20	0.33%	0.45%	0.50%	0.59%	0.78%	0.87%	1.26%	1.46%
Apr-20	0.18%	0.22%	0.28%	0.39%	0.55%	0.66%	1.06%	1.27%
May-20	0.16%	0.17%	0.22%	0.34%	0.53%	0.67%	1.12%	1.38%
Jun-20	0.18%	0.19%	0.22%	0.34%	0.55%	0.73%	1.27%	1.49%
Jul-20	0.15%	0.15%	0.17%	0.28%	0.46%	0.62%	1.09%	1.31%
Twelve-Month Average	1.02%	1.00%	1.01%	1.06%	1.19%	1.29%	1.65%	1.85%
Six-Month Average	0.40%	0.42%	0.45%	0.54%	0.72%	0.84%	1.27%	1.48%
Three-Month Average	0.16%	0.17%	0.20%	0.32%	0.51%	0.67%	1.16%	1.39%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated June 1, 2020 and July 31, 2020

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2020	Third	0.2%	0.2%	0.4%	0.7%	1.4%	2.4%	3.6%
2020	Fourth	0.2%	0.3%	0.4%	0.8%	1.5%	2.5%	3.7%
2021	First	0.2%	0.3%	0.5%	0.9%	1.6%	2.6%	3.8%
2021	Second	0.3%	0.3%	0.6%	1.0%	1.7%	2.7%	3.8%
2021	Third	0.3%	0.4%	0.7%	1.1%	1.8%	2.7%	3.9%
2021	Fourth	0.4%	0.5%	0.8%	1.2%	1.9%	2.8%	3.9%
Long-range CONSENSUS								
2021		0.4%	0.5%	0.7%	1.2%	1.8%	2.8%	4.1%
2022		0.7%	0.9%	1.1%	1.5%	2.2%	3.2%	4.5%
2023		1.3%	1.5%	1.7%	2.1%	2.7%	3.6%	4.9%
2024		1.8%	2.0%	2.2%	2.5%	3.1%	4.0%	5.2%
2025		2.1%	2.3%	2.5%	2.7%	3.3%	4.2%	5.3%
2026		2.3%	2.5%	2.7%	2.9%	3.5%	4.3%	5.4%
Averages:								
	2022-2026	1.7%	1.8%	2.0%	2.3%	3.0%	3.9%	5.0%
	2027-2031	2.6%	2.7%	2.9%	3.1%	3.8%	4.6%	5.7%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
31-Jul-20	2.4%	+	12.47%	=	14.87%

DCF Result for the S&P 500 Composite

D/P	(1+.5g)	+	g	=	k
1.74%	(1.0290)	+	5.80%	=	7.59%

Summary

Value Line			14.87%
S&P 500			7.59%
Average			11.23%
Risk-free Rate of Return (Rf)			1.75%
Forecast Market Premium			9.48%
Historical Market Premium			
Low Interest Rates	(Rm)	(Rf)	
1926-2019 Arith. mean	11.92%	2.88%	9.04%
Average - Forecast/Historical			9.26%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach

Using Non-Utility Companies with
Timeliness of 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 70 to 95; Betas of .75 to .95; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
ANSYS Inc	Computer Software	3	2	A	90	0.90	3
Brady Corp	Diversified Co.	3	3	B++	80	0.95	3
Brown Forman Corp (Class B)	Beverage	3	1	A	95	0.85	2
Caseys General Stores Inc	Retail/Wholesale Food	3	3	B+	85	0.80	3
Commerce Bancshares Inc	Bank (Midwest)	3	1	A	90	0.90	2
Cooper Companies Inc	Med Supp Non-Invasive	3	2	A	85	0.95	3
EchoStar Corporation	Cable TV	3	3	B+	75	0.90	3
Ennis Inc.	Office Equip/Supplies	3	3	B++	80	0.80	3
ESCO Technologies Inc	Diversified Co.	3	3	B+	90	0.95	2
Exponent Inc.	Information Services	3	3	B+	90	0.85	2
F5 Networks	Telecom. Equipment	3	3	A	75	0.90	3
FirstCash Inc.	Financial Svcs. (Div.)	3	3	B++	85	0.80	2
FLIR Systems Inc	Electrical Equipment	3	3	B++	70	0.95	3
Forrester Research Inc	Information Services	3	3	B+	70	0.95	3
Franklin Electric Co Inc	Electrical Equipment	3	3	A	70	0.95	2
Gentex Corp	Auto Parts	3	3	B++	85	0.95	2
Guidewire Software	Computer Software	3	3	B+	70	0.90	2
Hanover Insurance Group Inc	Insurance (Prop/Cas.)	3	2	B++	95	0.95	3
J and J Snack Foods Corp	Food Processing	4	1	A+	90	0.90	3
J B Hunt Transport Services Inc	Trucking	3	2	A+	85	0.95	2
Mettler Toledo International Inc	Precision Instrument	3	2	B++	90	0.95	3
Motorola Solutions Inc	Telecom. Equipment	3	2	B++	90	0.90	3
MSC Industrial Direct Co Inc	Machinery	3	2	A	75	0.95	3
Old National Bancorp	Bank (Midwest)	3	3	B+	80	0.95	3
Premier Inc.	Healthcare Information	3	3	B++	75	0.75	3
Quest Diagnostics Inc	Medical Services	3	2	B++	90	0.95	3
Salesforce Com Inc	E-Commerce	3	3	B++	80	0.85	2
Sensient Technologies Corp	Food Processing	3	3	B++	95	0.90	3
Stepan Company	Chemical (Specialty)	3	3	B++	70	0.85	3
Tetra Tech	Environmental	3	3	B++	85	0.90	3
Vail Resorts	Hotel/Gaming	3	3	B+	85	0.90	3
Walgreens Boots	Pharmacy Services	3	2	A+	85	0.80	3
Walt Disney Co	Entertainment	3	3	A	95	0.95	3
Werner Enterprises Inc	Trucking	3	3	B++	80	0.80	2
Average		3	3		83	0.90	3
Gas Group	Average	3	2	A	88	0.84	3

Source of Information: Value Line Investment Survey for Windows, August 2020

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2015-2019 and
Projected 3-5 Year Returns

Company	2015	2016	2017	2018	2019	Average	Projected 2023-25
ANSYS Inc	14.3%	14.6%	15.5%	19.4%	16.4%	16.0%	17.0%
Brady Corp	11.1%	13.3%	13.7%	14.9%	15.4%	13.7%	14.0%
Brown Forman Corp (Class B)	45.3%	48.8%	56.7%	50.7%	41.9%	48.7%	60.0%
Caseys General Stores Inc	20.9%	14.9%	11.2%	14.5%	16.1%	15.5%	12.5%
Commerce Bancshares Inc	11.2%	11.0%	11.8%	14.8%	13.4%	12.4%	8.0%
Cooper Companies Inc	7.6%	10.1%	11.7%	10.3%	12.9%	10.5%	13.0%
EchoStar Corporation	4.0%	4.6%	2.2%	0.9%	NMF	2.9%	3.5%
Ennis Inc.	12.0%	10.5%	12.5%	12.9%	13.0%	12.2%	12.5%
ESCO Technologies Inc	7.1%	8.3%	8.6%	9.0%	9.9%	8.6%	10.5%
Exponent Inc.	16.6%	17.4%	14.3%	23.0%	23.5%	19.0%	30.0%
F5 Networks	27.7%	30.9%	34.2%	35.3%	24.3%	30.5%	19.0%
FirstCash Inc.	14.1%	4.1%	7.9%	11.6%	12.2%	10.0%	12.0%
FLIR Systems Inc	13.4%	12.5%	13.7%	16.6%	16.2%	14.5%	15.5%
Forrester Research Inc	16.1%	16.5%	15.8%	16.5%	19.6%	16.9%	14.0%
Franklin Electric Co Inc	13.2%	12.8%	12.5%	14.6%	12.3%	13.1%	13.5%
Gentex Corp	18.5%	18.2%	18.0%	23.5%	21.9%	20.0%	23.0%
Guidewire Software	1.4%	1.9%	2.4%	NMF	1.3%	1.8%	1.5%
Hanover Insurance Group Inc	9.8%	6.5%	6.8%	9.9%	11.4%	8.9%	10.0%
J and J Snack Foods Corp	11.7%	11.9%	11.6%	11.1%	11.4%	11.5%	12.5%
J B Hunt Transport Services Inc	32.9%	30.6%	22.6%	29.7%	24.9%	28.1%	18.5%
Mettler Toledo International Inc	60.8%	88.4%	81.9%	83.6%	NMF	78.7%	NMF
Motorola Solutions Inc	-	-	-	23.2%	NMF	23.2%	NMF
MSC Industrial Direct Co Inc	17.5%	21.1%	18.7%	20.8%	20.0%	19.6%	22.0%
Old National Bancorp	7.8%	7.4%	6.0%	7.1%	8.4%	7.3%	9.0%
Premier Inc.	21.6%	19.7%	18.1%	21.2%	20.9%	20.3%	20.0%
Quest Diagnostics Inc	14.8%	15.9%	16.2%	16.8%	15.9%	15.9%	15.5%
Salesforce Com Inc	NMF	2.4%	1.4%	7.1%	0.4%	2.8%	7.0%
Sensient Technologies Corp	16.7%	17.2%	17.7%	18.3%	14.2%	16.8%	17.0%
Stepan Company	13.6%	13.6%	12.4%	14.4%	11.6%	13.1%	15.0%
Tetra Tech	11.9%	12.8%	13.3%	15.4%	17.8%	14.2%	17.0%
Vail Resorts	13.0%	17.1%	13.4%	23.9%	20.1%	17.5%	25.0%
Walgreens Boots	13.2%	16.8%	20.0%	23.0%	23.5%	19.3%	17.5%
Walt Disney Co	18.8%	21.7%	21.7%	25.8%	11.7%	19.9%	11.0%
Werner Enterprises Inc	13.2%	8.0%	7.8%	13.6%	15.0%	11.5%	11.5%
Average						17.5%	15.9%
Average (excluding companies with values >20%)						12.8%	12.6%

Comparable Earnings Approach
Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

PENNSYLVANIA PUC
PUBLIC UTILITY COMMISSION

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 NORTH STREET, HARRISBURG, PA 17120

IN REPLY PLEASE
REFER TO OUR FILE

August 16, 2018

REFERENCE:
NC-18-18
IREF: 10032

Mr. Michael J. Davidson
Vice President/General Manager
Columbia Gas of PA
121 Champion Way
Suite 100
Canonsburg, PA 15317

Dear Mr. Davidson:

On July 31 and August 1, Pennsylvania Public Utility Commission's Pipeline Safety Supervisors and Engineers lead by Mike Chilek and David Kline, including Robert Biggard, Sunil Patel, Lassine Niambele, and Kokou Apetoh, conducted an inspection of facilities and/or records in York, Pennsylvania. As a result of the inspection, the Pipeline Safety Division of the Pennsylvania Public Utility Commission has discovered that Columbia Gas of Pennsylvania is in violation of the following state and federal regulations:

(1) **49 CFR §192.1007 What are the required elements of an integrity management plan?**

A written integrity management plan must contain procedures for developing and implementing the following elements:

(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(e) Measure performance, monitor results, and evaluate effectiveness.

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

During the inspection of Columbia's Distribution Integrity Management Program (DIMP), it was discovered that elements of §192.1007 sections (b), (c), and (e) were not implemented and evaluated as required. These sections deal with identifying threats based on known incident history, evaluating and ranking risk by sub dividing system assets and measuring performance of risk rankings on a normalized scale.

CPA's DIMP plan section 7.1.2.2 parts (e) and (f) has written that Incident History will only be evaluated going back 5 years. Nowhere has CPA directly utilized their incident history beyond five years on the affected asset groups. CPA needs to thoroughly review and incorporate past incident data by asset type, pressure, conditions, cause, etc. to accurately identify the threats and ultimately the risk to better comply with §192.1007(b).

Optimain, one of CPA's risk modeling tools, currently has 19 of the top 20 riskiest main segments as bare steel. The underground steel main category is 12th on Columbia's risk ranking, although CPA still ranks it as "Critical". CPA's Subject Matter Expert (SME) and data driven portion of the risk model does not group pipeline assets into small enough groups. CPA should evaluate and rank risk for assets in smaller groups such as bare steel based on size, age, pressure, or any combination of these as the company deems necessary based on experience and operating history.

These bare steel main assets are being addressed thru Optimain and CPA's main replacement program. The DIMP plan seems to be out of sync with CPA's aggressive pipeline replacement program.

Columbia has moved to a data driven with SME input DIMP ranking process. The 2017 risk rankings had SME's moving some asset groups into the critical stage based on a number score up to 25. The Data driven scores are based on a zero to one scale.

At time of the DIMP inspection Columbia had not developed a process to normalize the risk rank scores to compare and measure effectiveness going forward. It is unclear how Columbia can measure effectiveness moving forward when trying to compare different scoring systems for ranking asset groups. This is not in compliance with §192.1007(e). Columbia should develop a process and procedure to normalize two different risk ranking scoring systems so the effectiveness of the DIMP plan can be evaluated.

Excavation damage appears to be is identified as an asset and given its own category in the risk rankings applying to all assets. Excavation Damage is a threat category and should be applied to specific assets in the same manner as corrosion threats or incorrect operation threats. Excavation damage threats should be used to influence the risk ranking of specific assets that are prone to damage. For instance, damage to a steel main which has couplings or appurtenances susceptible to pull-out may pose more of a risk than damage to a plastic main.

Excavation damage should be studied and evaluated as to which tangible assets (e.g. steel mains, plastic mains, service lines, steel and plastic, with or without flow valves, etc.) may be more of a risk than other assets. Another example would be damages may occur on older plastic mains because of poor records, construction methods, and incorrect mark outs. Incorporating this knowledge and data into CPA's risk rankings could create an asset titled "Excavation Damage Vintage Plastic Mains" instead of "Excavation Damage Poor Records".

Therefore, you are hereby requested to submit to this office on or before September 21, 2018 your company's plan to correct the compliance issues.

1) Columbia Gas of PA must review and incorporate all its known incident history and address these changes into section 7.1.2.2 parts (e) and (f) of its DIMP plan.

2) Columbia Gas of PA must study and evaluate assets in smaller groups, such as bare steel based on a combination of size and/or pressure.

3) Columbia Gas of PA changed their Risk Model for 2017 but has not normalized risk ranking scores between data driven results and SME issued data. Columbia should develop a process and procedure to normalize two different risk ranking scoring systems so the effectiveness of the DIMP plan can be evaluated.

4) Columbia Gas of PA must study and evaluate specific assets which may be higher risks by excavation damage.

This office is committed to ensuring that all pipeline companies comply with the provisions of the Public Utility Code. Therefore, you are advised that, if you fail to comply with the above requests this office will initiate all appropriate enforcement actions pursuant to the Public Utility Code against the utility and its officers, agents and employees.

Yours truly,

Paul J. Metro

Paul J. Metro, Manager
Safety Division
Bureau of Investigation and Enforcement

PM:bb

PC: Richard A. Kanaskie, Director, I&E
Michael Chilek, Fixed Utility Valuation Engineer Supervisor
Robert Biggard, Fixed Utility Valuation Engineer Supervisor

Columbia Gas of Pennsylvania
A NiSource Company

Michael J. Davidson
Vice President/General Manager

Southpointe Industrial Park
121 Champion Way, Ste. 100
Canonsburg, PA 15317
Phone: (724) 416-6308
Fax (724) 416-6383
mdavids@nisource.com

September 21, 2018

Paul J. Metro, Manager
Safety Division
Bureau of Investigation and Enforcement
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

RE: NC 18-18
IREF: 10032

Dear Mr. Metro:

The following is my response on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") to your letter dated August 16, 2018 regarding the Safety Division's Supervisors and Engineers Mike Chilek, Robert Biggard, David Kline, Sunil Patel, Lassine Niambele, and Kokou Apetoh inspection of Columbia's DIMP in York, Pennsylvania on July 31 and August 1, 2018.

Providing safe service to its customers and to the public is Columbia's top priority. The Company's DIMP Plan has been crafted with that priority in mind, and Columbia maintains that its DIMP Plan complies with (49 CFR §192 – subpart P). . With that stated, Columbia appreciates the findings and recommendations in your August 16, 2018 letter. Items 1), 2), 3), and 4) on page 3 of your August 16, 2018 letter, and Columbia's responses are as follows:

1) Columbia Gas of PA must review and incorporate all its known incident history and address these changes into section 7.1.2.2 parts (e) and (f) of its DIMP Plan.
2) Columbia Gas of PA must study and evaluate assets in smaller groups, such as bare steel based on a combination of size and/or pressure.
3) Columbia Gas of PA changed their Risk Model for 2017 but has not normalized risk ranking scores between data driven results and SME issued data. Columbia should develop a process and procedure to normalize two different risk ranking scoring systems so the effectiveness of the DIMP plan can be evaluated.
4) Columbia Gas of PA must study and evaluate specific assets which may be higher risks by excavation damage.

Response:

1) In reference to the concern over incident history, the Company has chosen a 5 year baseline for its performance measures and will consider expanding its baselines for all performance measures going forward, and reflect as such in the framework. It is important when determining baselines to take the quality of the available data into consideration. Columbia began performing QA/QC on its leakage data in 2013. Consequently, leakage data prior to that time does not assist in the identification of threats, and beginning a baseline with that year is the most appropriate. Columbia does include a 20 year history of reportable incidents in Appendix A, of the DIMP plan, which is reviewed annually by Columbia of Pennsylvania DIMP Steering team's Subject Matter Experts (SMEs) to determine if certain risks should be elevated in the model.

2) Columbia's parallel approach, using DIMP risk model for system-level risk and using Optimain (among other tools and methods) for segment-level risk, already includes both asset/threat analysis required in §192.1007 and the Safety Division's segment-oriented suggestions. Both approaches use SME validation as a secondary check for each approach's data-driven results, with any changes in each approach's results made on an exception basis. Each approach allows for the evaluation of risk in ways that the other approach inherently does not. Since the two approaches inherently assess assets and threats through different lenses for different operational decisions, attempting to hybridize system-level and segment-level approaches would, in the Company's opinion, reduce the effectiveness of both approaches.

Columbia recognizes the disparity between the data driven risk scores and the SME evaluation of the adjusted ranking. This new process will be refined and enhanced as we move forward with a Safety Management System (SMS) approach. However, it is important to note that the priority threshold assigned to the risk (critical, major, significant, low) is based upon data and/or SME evaluation. The priority threshold is the main focus of the DIMP Steering Team for review of the Accelerated Actions, more so than the raw numerical score.

3) Columbia maintains that, on the system wide level, the type of asset does not impact excavation damage as a threat. A damage may occur regardless of the asset type. The accelerated actions are developed with the holistic approach of reducing the threat of excavation damage. The asset, area, and root cause prevention are developed and ranked by the Damage Prevention Team based on the system wide actions.

Columbia welcomes best practice recommendations for its DIMP and will provide these suggestions to the Columbia of Pennsylvania DIMP Steering team for further discussion. Columbia expects to move forward with a Safety Management System (SMS) approach in the near future. The expectation is that SMS and DIMP will work in concert to continue to enhance overall system integrity.

I trust these actions will address the concerns that you addressed in your August 16, 2018 correspondence. Should you wish to discuss the issue further, please do not hesitate to contact me at 724-416-6308.

Sincerely,

Michael J. Davidson

Michael J. Davidson

cc: T. Gallagher
J. Roberts
R. Burke
M. Seto

7-1 SME RISK EVALUATION FORM

Reference Number: ☐**Complete** **Complete Date:**

SME Sponsor:
SME Title:
SME Area:

RISK DESCRIPTION

This section is to be completed by a member of the DIMP Administrative team. Provide information about the risk that the Steering Team wishes to evaluate.

Asset:

Threat:

General/ Situational Risk: Choose an item.

Original Risk Level: Choose an item.

Evaluation Remarks:

PROBABILITY FACTOR

This section is to be used to determine an SME Probability Factor using the PSMS Risk Matrix

LOW		MEDIUM		HIGH	
☐Rarely–1	☐Unlikely–2	☐Possible-3	☐Likely–4	☐Probable–5	☐Certain–6

Remarks:

CONSEQUENCE FACTOR

This section is to be used to determine an SME Consequence Factor using the PSMS Risk Matrix

LOW		MEDIUM		HIGH	
☐Negligible–1	☐Minor–2	☐Moderate–3	☐Significant–4	☐Major–5	☐Extreme–6

Remarks:

SME RISK EVALUATION RESULT		
SME Risk Score: Choose an item.		
☐	☐	☐
LOW	MEDIUM	HIGH
Risk level is low (green).	Risk level is medium (yellow).	Risk level is high (red).
Remarks:		
DIMP Steering Team Agreement		
Choose an item.		

RISK MATRIX

CONSEQUENCE SCALE									
EXTREME	•Extreme Damage; Long- term on-site/off-site environmental damage •Willness or injury is widespread or serious, or may result in long-term illness, disability or death •Enterprise-wide disruption	6	6	12	18	24	30	36
MAJOR	•Major Damage and unplanned O&M; Short-term on-site/off-site environmental damage •Illness or injury to a group; requires hospitalization care (OSHA Reportable or OSHA Recordable Lost Time or Restricted Duty) •Multiple Operating Co. level disruption of critical service	5	5	10	15	20	25	30
SIGNIGICANT	•Significant Damage and unplanned O&M; Long-term on-site environmental damage •Illness or injury; requires medical care (OSHA Reportable or OSHA Recordable Lost Time or Restricted Duty) •Operating Company level extended disruption of critical service	4	4	8	12	16	20	24
MODERATE	•Moderate Damage and unplanned O&M; Short-term on-site environmental damage •Illness or injury to a group; requires medical care but does not result in long-term illness or disability •Localized (single unit/department) disruption of less than 1 week	3	3	6	9	12	15	18
MINOR	•Minor damage and unplanned O&M; Environmental damage immediately contained •Minor illness or injuries ("Other" OSHA Recordable Injury) •Localized (single unit/department) disruption of less than 1 day	2	2	4	6	8	10	12
NEGLIGIBLE	•Near miss or public safety event averted; No environmental damage •Minor illness or injuries to a small number of people, treatable with first aid or basic care •Localized (single \ unit/department) disruption of hours	1	1	2	3	4	5	6
LIKELIHOOD SCALE			1 RARELY	2 UNLIKELY	3 POSSIBLE	4 LIKELY	5 PROBABLE	6 CERTAIN
IMPACT ON PIPELINE SAFETY		General	Almost inconceivable that the risk will occur	Risk is only remotely likely and has a low chance of occurring in the next 13 - 24 months	Risk is possible and has a medium chance of occurring in 13 - 24 months	Risk is likely and has a medium chance of occurring in 4 - 12 months	Risk is probable to occur in the next 1 - 3 months	Risk is certain to occur in the next 1 - 3 months
		Peer Experience	Has occurred at other utilities rarely	Has occurred very infrequently at other utilities	Has occurred within the past 13 - 24 months at other utilities	Has occurred within the past 4 - 12 months at other utilities	Has occurred within the past 1 - 3 months at another utility	Has occurred within the past 1 - 3 months at multiple utilities
		Current Readiness	Existing measures to manage risk are effective in limiting chance of occurrence in most circumstances	Existing measures to manage risk are effective in limiting chance of occurrence	Existing measures to manage risk are mostly effective in limiting chance of occurrence	Existing measures to manage risk are only partially effective in limiting chance of occurrence	Existing measures to manage risk are not very effective in limiting chance of occurrence	Ineffective or non-existent measures in place to manage risk
		Event Frequency	Could happen only in extraordinary circumstances	Happens, but infrequently	Could happen at some time	Should happen at some time	Will happen in most circumstances	Happens frequently

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocate – Set 2

Question No. OCA 2-036:

Referring to Statement No. 7, Pages 20-27, please provide documentation supporting the costs associated with each of the referenced programs.

Response:

See OCA 2-036 Attachment A for documentation supporting the costs associated with the Workforce Transition - Gas Qualification Specialists and Legacy Service Line Enhancement Program.

See OCA 2-036 Attachment B for documentation supporting the costs associated with the Picarro Leak Detection Program.

See OCA 2-036 Attachment C for documentation supporting the costs associated with the Legacy Cross Bore Program.

See OCA 2-036 Attachment D for documentation supporting the costs associated with the Field Assembled Riser Replacement Program.

CPA Field Assembled Riser Replacement Program

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	TOTAL
Projected Units	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	27,118
Projected Cost/Unit 1_/	$ 625	$ 638	$ 650	$ 663	$ 677	$ 690	$ 704	$ 718	$ 732	$ 747	$ 684
Projected Spend	$ 1,694,875	$ 1,728,773	$ 1,763,348	$ 1,798,615	$ 1,834,587	$ 1,871,279	$ 1,908,705	$ 1,946,879	$ 1,985,816	$ 2,025,533	$ 18,558,408

Footnote:
1_/ Projected cost per unit includes a 2% year over year escalator

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 8

Question No. OCA 8-001:

Referring to the response to OCA-II-36 Attachment D (CONFIDENTIAL), please explain why the Company is waiting until 2021 to commence the replacement of customer-owned field assembled risers, rather than having begun the program in 2019 or 2020.

Response:

Columbia began the replacement of customer-owned field assembled risers in 2018 and is currently replacing customer-owned field assembled risers. Please see Columbia's response to I&E-GS-008 for the number of customer-owned field assembled risers replaced for years 2018 through 2019.

Question No. OCA 8-002
Respondent: M. Davidson
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COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 8

Question No. OCA 8-002:

Referring to the response to OCA-II-36 Attachment D (CONFIDENTIAL), please describe the costs included in the estimated per unit cost of $625 for 2021 and describe how those costs were estimated.

Response:

The estimated cost per unit include labor, materials & supplies, outside services and other (e.g. overhead, fleet, etc.). Additionally in Columbia's 2018 Petition for Limited Waivers of Certain Tariff Rules Related to Replacement of Customer Service Lines and Field Assembled Risers (Docket No. P-2018-2641560), Columbia estimated a cost range of $600-$750 per riser which was based on the company's program to address company owned field assembled risers. Columbia utilized a conservative estimate of $625 per riser as a basis for the incremental request in this rate case proceeding. Furthermore, as represented in OCA 8-001, Columbia started addressing customer owned risers in 2018 with a higher quantity of replacements taking place in 2019. Based off the number of 2019 replacements in our Western Pennsylvania service territories which is where the majority of customer owned facilities are located, Columbia realized an average cost of replacement closer to $635 per riser.

Question No. OCA 8-003
Respondent: M. Davidson
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COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 8

Question No. OCA 8-003:

Referring to the response to OCA-II-36 Attachment D (CONFIDENTIAL), please explain how the projected number of units of 2,712 per year was determined.

Response:

The projected number of units of 2,712 risers per year was based on the estimated number of customer owned field assembled risers in Columbia's 2018 Petition for Limited Waivers of Certain Tariff Rules Related to Replacement of Customer Service Lines and Field Assembled Risers (Docket No. P-2018-2641560) minus the number of customer owned field assembled risers replaced represented in Columbia's response to I&E-GS-008 for years 2018 through 2019 and projected volume to be replaced in 2020. The total, as described above, was applied utilizing a straight line method over the course of 10 years.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 8

Question No. OCA 8-004:

Please describe any steps that the Company has taken to date in 2020 to commence the replacement of customer-owned field assembled risers.

Response:

With respect to the customer owned riser replacement program, the COVID-19 pandemic temporarily impacted the company's ability to replace customer owned risers. Columbia plans to restart the customer owned riser replacement efforts in August and anticipates completing approximately 400-500 risers through the remainder of the year.

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-2020-3018835

August 26, 2020

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

INTRODUCTION

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 April 24, 2020.

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 St. 3), Christopher Keller, a witness appearing on behalf of the Commission's Bureau of Investigation and Enforcement ("I&E") (I&E St. 2), Mr. Robert D. Knecht, a witness appearing on behalf of the Office of Small Business Advocate ("OSBA") (OSBA St. 1), and Mr. James L. Crist, a witness appearing on behalf of Pennsylvania State University ("PSU") (PSU St. 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. Have you prepared an exhibit to accompany your rebuttal testimony?

A. Yes. I have prepared an update of my original Exhibit No. 400. In this exhibit, I have updated the Company's cost of debt and provided later data regarding the cost of equity. With these later data, I determined that my original recommendation continues to be valid.

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 proposed cost of debt in this case. Mr. O'Donnell also accepted the Company's proposed cost of debt. Messrs. Knecht and Crist do not comment on the capital structure ratios. The cost of equity has been disputed by each of the witnesses. The equity returns proposed by the I&E, OCA and OSBA witnesses are entirely too low to reflect the risks of CPA and the prospective cost of equity. This is especially apparent with the proposals of the OCA and OSBA.

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 opposing party recommendations 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:

- The impact of the coronavirus pandemic, the collapse of crude oil prices, and the end of the record-setting 128-month economic expansion that occurred in February 2020 that have impacted the cost of equity and have been reflected in the data I used in compiling an update in my analysis.
- Comparable Companies – Mr. Keller has made several deletions to the members of my Gas Group. Mr. O'Donnell has adopted my Gas Group with one addition and has separately analyzed the data for NiSource, Inc. 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.

- Discounted Cash Flow (DCF) – The DCF results proposed by the OCA witness is 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 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.

CAPITAL STRUCTURE

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.

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 the average common equity ratio established in rate case decisions by other state regulators. 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 and substituting a hypothetical capital structure.

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 13), the Company's actual capital structure ratios are fairly comparable to the companies in the comparison group and are therefore entirely reasonable and acceptable. 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 most recently approved common equity ratio by this Commission rather than rely 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. This is the most relevant benchmark common equity ratio for comparative purposes in this case. Indeed, the Company's proposed common equity ratio of 54.19% is entirely reasonable based on prior Commission action. Moreover, the reasonableness of the Company's actual capital structure containing a common equity ratio of 54.19% 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 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 average common equity was 52.23%, with a range from 39.80% to 62.30% (see OCA St. 3 at page 30). This comparison supports the actual 54.19% common equity ratio for CPA. Mr. Keller found that the range of common equity ratios for his Barometer Group was from 33.18% to 53.48% for 2019 and 32.78% to 59.01% for the five-year average (see I&E St. 2 at page 12). Here, the Company's actual common equity ratio falls within that range. Hence, the Company's actual common equity ratio conforms with Commission policy that states that the actual, not hypothetical, common equity ratio will be employed when it falls within the Barometer Group's range.

Q. But, Mr. O'Donnell points out (see page 35 of OCA Statement 3), that when including short-term debt in the comparison, the common equity ratio for your Gas Group is lower. Please explain.

A. Mr. O'Donnell's observation in this regard is not valid for rate case purposes. The common equity ratios that he cites from my Exhibit No. 400 include short-term debt at fiscal/calendar year end. For gas distribution utilities, these amounts are typically near the peak amount for the reporting period. For rate cases, we use our average amount of short-term debt to accommodate the seasonal nature of short-term borrowings. This mismatch of Mr. O'Donnell's observation makes his comparison invalid.

Q. Is Mr. O'Donnell's capital structure proposal consistent with the historic capital structure experience of CPA, shown on Schedule 2 of Exhibit No. 400?

A. No. At pages 35-36, Mr. O'Donnell contends that the capital structure ratio for CPA is without support. However, CPA provided Mr. O'Donnell with data in support of the Company's capital structure ratio. (See Exhibit PRM-1R, attached hereto). This shows the need for additional capital to finance rate base growth, including retained earnings, additional paid in capital, and additional debt. I should note that the Company retains all of its earnings rather than pay dividends to support its pipe replacement program.

Mr. O'Donnell also references NiSource as further support to pull down the common equity ratio. NiSource is not the appropriate focus because it is a holding company and it is not appropriate to compare an operating utility capital structure to a holding company capital structure.

Moreover, Mr. O'Donnell has not substantiated his position regarding the selection of hypothetical capital structure ratios, other than it achieves a lower common equity ratio. 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 altering the debt cost rate for CPA. This results in a serious mismatch of debt ratio and 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.

COST OF LONG-TERM DEBT UPDATE

Q. Have you updated the Company's cost of debt?

A. Page 3 of Schedule 6 of Exhibit No. 400 (Updated), which is attached, provides the Company's cost of debt for the FPFTY. It reflects the actual cost of the new issue of promissory notes that were issued in March 2020. I have carried forward the interest rate from that issue to the planned new issue of Senior Notes in the FPFTY. As shown on page 3 of Schedule 6 of Exhibit No. 400 (Updated) the embedded cost of long-term debt is 4.73% for the FPFTY. This change increased the overall cost of debt by 0.03% (4.73% - 4.70%), from my original proposal. Company witness Miller has adjusted the revenue requirements for this change.

COST OF EQUITY UPDATE

Q. Have you updated your cost of equity analysis for CPA?

A. I have prepared an update of the data that I used to measure the cost of equity for several reasons. With these later data, I have measured the impact of the coronavirus pandemic and the collapse of crude oil prices on my recommendation by looking at recent financial and economic data. This analysis shows that the pandemic has materially increased CPA's cost of common equity.

However, it is my opinion that public utility ratemaking is prospective, and that rates, including the cost of common equity, should reflect conditions during the FPFTY and for the period rates are expected to be in effect. For this reason, I have not altered my recommended cost of equity for CPA in this proceeding even though the updated evidence shows that a higher cost of equity is now warranted.

Q. Have recent events caused you to review the soundness of your recommendation?

A. Yes, but the impact of those events have not changed my recommendation. Extraordinary events around the COVID-19 pandemic have transpired since the preparation of my direct testimony in this case. The market data that I originally used in this case contained information through December 2019. Since that time, there has been significant turmoil that has rocked the stock and bond markets in the February-May 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 we entered a recession in February 2020, a historic rout in stock prices and extraordinary actions by the Federal Open Market Committee ("FOMC") to address these disruptions had a dramatic impact on the capital markets. These actions brought the Fed Funds rate to near zero. How these events are fully resolved is yet to be determined.

Q. Have you considered these changed fundamentals in your cost of equity analysis?

A. Yes. I have considered these events as they impact the inputs that I used in the various models of the cost of equity. Indeed, these impacts should be considered, but only as to their prospective impact during FPFTY and expected rate effective period. Resetting the cost of equity based on the extraordinary and non-recurring conditions that exist today is not appropriate in my view.

However, the Commission may want to examine the effects of the pandemic in making its determination of prospective rates in this proceeding. To do so, I have recalculated my cost of equity models using input data that includes conditions associated with the economic recession. I have accomplished this by using a three-month average period in compiling my later data. I have done this to avoid mixing expansion data with recession market data in my update. In the post expansion period, a 3-month period and current projections are far more representative of what the prospective cost of capital will be during the FPFTY than the data prior to the coronavirus outbreak. I emphasize that I am not departing from my long-standing approach of using six-month data, and I am not changing my recommendation. As shown below, however, if this recent data were used, my recommendation would increase from my original recommendation.

Q. How have the results of the various measures of the cost of equity performed in your additional analysis?

A. Those results are shown on page 2 of Schedule 1 of CPA Exhibit No. 400 (Updated). Other than shifting to a three-month average in the update, all procedures used to apply each of the models of the cost of equity are the same as in my direct testimony. On page 2 of Schedule 1, I have shown the comparison of the updated cost of equity results and the difference in the outcomes from my original analysis contained in Statement No. 8. You will see that the DCF result moved up by a meaningful amount due to the increase in the dividend yield (i.e., 3.39% currently vs 2.69% formerly) and the leverage adjustment. The growth rate that I used in the DCF has not changed so that the later DCF calculation is 1.01% higher than the former one (12.92% - 11.91% = 1.01%). Indeed, the update of the range of earnings per share growth rates is 6.20% to 10.06%, which is not materially different from the original range of 5.94% to 10.06%. Even setting aside the leverage adjustment, the simple dividend yield plus growth return moved from 10.19% originally to 10.89% in the update, or an increase of 0.70%.

The Risk Premium approach shows a downward change in the cost of equity in the update. It should be noted that an increase in the risk premium value provided some offset to the decline in the prospective yield on A-rated public utility debt.

The revised CAPM results of 12.49% show a significant increase in the cost of equity. The increase can be traced to two factors; those being an increase in the beta ("β) measure of systematic risk and an increase in the market premium that is represented by the return on the overall market less the risk-free rate of return ("Rm-Rf"). These increases have been offset by the decline in the risk-free rate of return. That decline was a response to the FOMC that began to reduce the federal funds rate (i.e., the FOMC had indicated 0.25 percentage point reductions to the federal funds rate on July 31, 2019, September 18, 2019, and October 30, 2019), in response to a perceived weakening of the global economy due in part to the U.S.'s trade war with China. The FOMC specifically noted weakness in business fixed investment and exports. Further action was taken by the FOMC to support the money and capital markets during the coronavirus pandemic. This brought the Fed Funds rate to near zero. The risk-free rate of return that I used in the CAPM is based upon the yields on 30-year Treasury bonds, which in my opinion, will be 1.75% on a prospective basis (the July 2020 yield was 1.31%). Along with the decline in the risk-free rate of return, the market premium ("Rm-Rf") has increased, which makes perfect sense because that premium increases with the decline in interest rates. Also noteworthy is the change in the beta. The leverage adjusted betas has increased from 0.83 to 1.05 in my update. Even without the leverage adjustment, the Value Line beta has increased from 0.66 to 0.84. This shows a meaningful increase in the systematic (i.e., market) risk for the Gas Group since my direct testimony was prepared.

Lastly, the Comparable Earnings approach shows a slight decline in results. Those results will be subject to further pressure as the consequences of the current recession become clearer on the prospective returns for these non-regulated companies.

Q. Do you propose any change in your recommended equity return attributed to your update?

A. No. The results of my various models of the cost of equity show some decline (i.e., Risk Premium and Comparable Earnings) or a significant increase in the cost of equity (i.e., DCF and CAPM), as compared to my original study. An average of all differences in model results show an increase in the cost of equity of 0.72%. I continue to support the 10.95% return on equity that includes the increment for management performance.

OPPOSING PARTIES EQUITY PROPOSALS AND RELEVANT MARKET FUNDAMENTALS

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. Further, the Commission should reject the proposal by Mr. O'Donnell to set the Company's return at 8.50%. A cost of equity return of 9.86% as proposed by Mr. Keller, while still inadequate and not fully reflective of more recent market conditions is far more reasonable and shows that not only is Mr. O'Donnell's proposal unreasonable, but that Mr. Knecht's proposal of 7.50% is even more unreasonable. 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. Knecht are much too low to reflect the risk and return for CPA.

Q. How do Mr. Keller's, Mr. O'Donnell's, and Mr. Knecht's recommendations compare

with recently authorized equity returns?

A. The Commission has decided the cost of equity for the Electric Division of UGI Utilities in a rate case decision that established a cost of equity of 9.85%. The business profile of CPA is considered riskier from a financial perspective than electric distribution businesses, so a 9.85% return on equity would be insufficient.

Q. Has the Commission decided the return on equity issue in other, more recent rate cases?

A. Yes. The Commission set the return on equity at 9.54% for Citizen's Electric Company on April 27, 2020 at Docket No. R-2019-3008212, at 9.73% for Valley Energy, Inc. on April 27, 2020 at Docket No. R-2019-3008209, and at 9.31% for Wellsboro Electric Company on April 29, 2020 at Docket No. R-2019-3008208. In each case, the return on equity determination was based primarily on the DCF method, with CAPM providing a comparison result. Since the facts of those cases do not bear directly upon CPA, they do not provide much guidance for resolving the return on equity in this proceeding. But what they do show is the positions of the OCA and OSBA (i.e., 8.50% or 7.50% respectively) are totally inadequate for CPA.

Q. How do Mr. Keller's, Mr. O'Donnell's, and Mr. Knecht recommendations compare with the recently authorized DSIC equity return for gas utilities?

A. They are lower. The Commission has recently set the equity return for the DSIC in its Quarterly Earnings Report (see Docket No. M-2020-3020940 at Public Meeting held August 6, 2020). There, the Commission set the return on equity for the DSIC at 10.10% for gas distribution utilities, which should be considered the floor of returns that should guide the rate of return determination in this case. Indeed, it should be noted that the Commission increased the DSIC return by 0.10% for the gas distribution utilities in its recent decision.

Q. Why would the 10.10% 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, the DSIC return receives a true-up such that the achieved returns on DSIC investments equal the intended return in those proceedings. 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.

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 any of the positions of the OCA or OSBA. 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 OSBA?

A. If the Commission were to follow the proposals of OCA or OSBA, 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. The higher the index the greater the risk. 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. Since April 2020, the VIX has averaged 35.32, which points to high risk in the equity market. The Commission could be guided in deciding the return on equity in this case by looking back to the last time when the VIX was showing high risk. That time would be for the years 2008 and 2009 during the Financial Crisis. The average VIX for 2008 and 2009 was 34.04 and 32.83, respectively. During that time, natural gas distribution utilities nationally were on average granted returns on equity of 10.39% in 2008 rate cases and

10.22% in 2009 rate cases decided during a period of similar market turmoil (see Exhibit PRM-2R). This shows that returns, such as 7.50% or 8.50% are totally inadequate.

Q. At page 40 of OCA Statement No. 3, Mr. O'Donnell observes that regulated ROEs have trended downward over the past 15 years. Please respond.

A. They have. But at the same time the regulatory premiums, i.e., the authorized returns less the corresponding public utility bond yields, have increased. This is shown by the data provided below and shown in Exhibit PRM-2R.

Years	Number of Years	Average Regulatory Risk Premium
1984-2019	36	4.00%
2000-2019	20	4.72%
2010-2019	10	5.41%
2015-2019	5	5.61%

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. 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 risk factors affecting CPA.

PROXY GROUP

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 most of the companies in my Gas Group and inserts UGI Corporation in the Comparison Group, but 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. There is no reason to look at NiSource separately in this case.

Q. Should UGI Corporation be included in the Comparison Group?

A. No. Non-utility operations comprise 87% of revenues, 48% of net income, and 73% of assets for UGI Corporation. This makes UGI Corporation a non-comparable company, because its risk is higher CPA. It should not be included in a Comparison Group for this case.

Q. Mr. Keller used the percentage of revenues devoted to utility operations as a criterion for screening companies to assemble his Barometer Group. Please explain why this is not the correct criterion.

A. For utilities, the percentage of regulated revenues cannot be used to select members of the Barometer Group 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-6:

		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 60% for all members of my Gas Group. As such, these data show that no elimination to my Gas Group is appropriate in this case.

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 certainly 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.[1] The use of multiple methods provides 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.[2]

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.

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[1] The growth rate variables shown on Schedules 8 and 9 of CPA Gas Exhibit No. 400 shows that the assumption associated with the simplified DCF model are not reasonable.

[2] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

A. I used a 7.50% growth rate for my Gas Group. Mr. Keller used 6.52% (the actual growth rate was 7.64%, which Mr. Keller adjusted by excluding the Value Line growth rate estimate for Northwest Natural Gas) for his Barometer Group (see I&E Ex. 2 – Schedule 7) and Mr. O'Donnell used a 4.0% to 6.0% growth rate for his Comparison Group (see OCA Statement No. 2 at page 56).

Q. Do the DCF results utilized by Mr. Keller provide a reasonable representation of the cost of equity?

A. There is an anomaly in one of Mr. Keller's results. The principal purpose of assembling a Barometer Group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the Barometer Group results 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, one of the DCF results presented by Mr. Keller falls into that category:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Northwest Natural Gas	3.25%	+	3.10%	=	6.35%

The reason that the DCF return for Northwest Natural is so low can be traced to Mr. Keller's exclusion of the Value Line forecast for this company. He excluded the one high data point for Northwest Natural Gas, and then retains growth rates from other sources that are much too low. He improperly throws out a high number while retaining unreasonably low numbers for one company. This introduces a bias to his result.

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.	2.47%	+	7.21%	=	9.68%
CPK	Chesapeake Utilities, Inc.	2.16%	+	6.87%	=	9.03%
NI	NiSource, Inc.	3.83%	+	6.87%	=	10.70%
OGS	One Gas, Inc.	3.00%	+	5.67%	=	8.67%
SJI	South Jersey Industries	4.84%	+	10.97%	=	15.81%
SR	Spire, Inc.	3.79%	+	4.96%	=	8.75%
	Average	3.35%	+	7.09%	=	10.44%

Q. At page 24 of I&E Statement No. 2, Mr. Keller excludes the <u>Value Line</u> growth estimate for Northwest Natural from his analysis. Do you agree?

A. No. Mr. Keller says, "Value Line's growth projection for Northwest is extremely inconsistent and would have an unreasonable and unwarranted impact on my DCF analysis." However, Mr. Keller's approach to excluding the Value Line growth rate for Northwest is one-sided. He advocates the exclusion of a high growth rate, but he makes no effort to exclude any low growth rates. There is a clear bias to his exclusion. As I demonstrated above, by altering the growth rate for Northwest Natural, Mr. Keller has made its result an outlier that artificially lowers his overall DCF result. Moreover, the use of a group average without alternation will give appropriate weight to both high and low growth rates, and as such all values (e.g. high and low) should be used in the analysis.

Q. What would be the DCF result if Northwest Natural were treated equal to the other members of Mr. Keller's Barometer Group?

A. Certainly, the DCF return would have been much higher if Mr. Keller had not eliminated the forecast earnings projection by <u>Value Line</u> for Northwest Natural. If he had maintained the <u>Value Line</u> earnings growth for Northwest Natural and averaged it with earnings growth rates from other sources the growth rate would have been 10.90% for this company and the DCF return for Northwest Natural Gas would have been 14.15% (dividend yield of 3.25% plus growth of 10.90%) (see I&E Ex. 2, Schedules 6 and 7). This correction thereby increases the Barometer Group average DCF return to 10.98% (3.34%

+ 7.64%).

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 May 1, 2020 to July 24, 2020 (see OCA ST. 3 at page 45). He arrives at a range of dividend yields of 3.3% to 3.5%. He then adds a growth rate taken from five sources. He employs the use of a "plowback" method, <u>Value Line</u> historical growth rates of earnings, dividend and book value, <u>Value Line</u> forecasts of earnings, dividends and book value growth, and earnings forecast by CFRA and Schwab (see OCA St. 3 at pages 46-56).

Q. At page 56 of OCA Statement No. 3, Mr. O'Donnell claims that it would be inaccurate to use only earnings growth rates in the DCF because the DCF formula is dependent on future dividend growth. Do you agree?

A. No. To mitigate this alleged problem, Mr. O'Donnell presents EPS, DPS, and BPS growth rates. 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. 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.[3] Therefore, his 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 is 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 (plowback), or its surrogate retention 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 10.1% for 2023-2025 (see Exhibit KWO-3) 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., 3.30%

[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

+ 3.5% + 3,5% = 10.3% ÷ 3 = 3.43%)

Return on Equity	10.10%
Dividend Yield on Book Value	-5.80%
Dividend Yield on Market Value	3.43%
Result	7.73%

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 10.10% should be reduced to 7.73%. 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 9.3% by Value Line, 6.7% by CFRA, and 6.7% by Schwab (see Exhibit KWO-1). The average earnings per share growth rate is 7.57% (9.3% + 6.7% + 6.7% = 22.7% ÷ 3). The resulting DCF return is 11.00% (3.43% + 7.57%). This provides a far more reasonable DCF result than the 8.40% (7.3% + 9.5% = 16.8% + 2) midpoint DCF return advocated by Mr. O'Donnell (see OCA St. 3 at page 56). As I describe in my pre-filed direct testimony, forecast earnings growth is the only valid measure of growth for DCF purposes. The theory of DCF indicates that the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share and dividend growth will equal earnings growth with a constant payout ratio. Unfortunately, a constant payout ratio reflects neither the reality of the equity markets or investor expectations. Therefore, to 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 primary emphasis. Indeed, my DCF result, even setting aside the leverage adjustment, is 10.89% (see Schedule 7 of Exhibit No. 400 (Updated)).

COST OF COMMON EQUITY - LEVERAGE ADJUSTMENT

Q. At pages 39-44 of I&E Statement No. 2, Mr. Keller responds to your leverage adjustment and argues that it should be rejected. Do you agree?

A. Among his reasons for opposing the leverage adjustment, Mr. Keller says, the rating agencies use book value in their analysis, it was rejected by the PUC in other cases and "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," which "demonstrates that investors base their decision on book value debt and equity ratios for the regulated utilities," so "no adjustment is needed." As explained above, there is no merit to these arguments of Mr. Keller. In his discussion of my leverage adjustment, Mr. Keller mentions market-to-book ratios ("M/B"). I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio (see I&E St. 2 at page 39). 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 42). 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 42-43). Please comment.

A. Mr. Keller points to several decisions where the Commission declined to make a leverage adjustment – i.e., rate cases including Aqua Pennsylvania, the City of Lancaster Water Department, and UGI – Electric Division (see I&E St. 2 at page 43). 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. Just like 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[4] 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 when arriving at a 9.85% equity return.

Q. Third, Mr. Keller argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

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[4] 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.

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 I&E St. 2 at pages 43-44). 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 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 (Updated). 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 78-80 of OCA Statement No. 3, 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" and is "an attempt to justify an unreasonable return on equity for the Company." 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.

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, (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 unreflecting of the forward-looking prescription of the CAPM that requires use of investor-expected returns.

Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The <u>Blue Chip</u> report dated July 31, 2020 shows this comparison. For the second quarter of 2020, the gap was 0.69% (1.38% - 0.69%) between the yields on 30-year and 10-year Treasury obligations. For the period 2022-2026, that gap is projected at 0.70% (3.0% - 2.3%) as shown by the comparison on page 2 of Schedule 13 of Exhibit No. 400 (Updated). This shows a systematic understatement of Mr. Keller's CAPM returns. 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 10 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 2020 and the first, second and third quarters of 2021 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, 2020. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2021	1.20%	1.80%
2022	1.50%	2.20%
2023	2.10%	2.70%
2024	2.50%	3.10%
2025	2.70%	3.30%
2026	2.90%	3.50%
Average	2.15%	2.77%

The resulting risk-free rate of return is 2.15% using the yield on 10-year Treasury Notes, as compared to Mr. Keller's 1.22%, and 2.77% 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 pages 39 of CPA Statement No. 8). Those results are:

	Rf	+	*β*	(	*Rm*	-	*Rf*	) +	*size*	=	*K*
Barometer Group	2.15%	+	0.82	(	10.35%	-	2.15%	) +	1.02%	=	9.89%

This CAPM result employs the betas ("β) and market return ("Rm") proposed by Mr. Keller.

Q. At pages 45-46 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. 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 5.5% and 7.5% (see OCA St. 3 at page 68). This clearly is totally inconsistent with the CAPM that I revised using Mr. Keller's data, the DCF, and the Comparable Earnings 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 OCA St. 3 at page 65). 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% (12.1% - 6.0%) as revealed in the 2020 SBBI Yearbook.[5]

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 4.0% to 6.0%. 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 provides any double-counting for this risk factor (see page 87 of OCA St. 3). A size adjustment is necessary because the financial impact of 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:

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[5] Ibbotson® Stocks, Bonds, Bills and Inflation ("SBBI") 2020 Classic Yearbook (Morningstar): p10-7

> 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.

COST OF COMMON EQUITY – OTHER METHODS

Q. At page 16 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 page 20 of I&E St. 2). And he further asserts that the Comparable Earnings method is too subjective, 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. 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 pages 31-35). 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 89 of OCA Statement No. 3, Mr. O'Donnell disagrees with your Risk Premium results because he believes that the best predictor of future yields are the current yield. 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. What does Mr. Keller say about your Risk Premium analysis?

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 19-20 of I&E St. 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 10.50%, and 10.10% as updated. Hence, my Risk

Premium cost rate is fully responsive to changing market fundamentals.

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.[6]

Q. At page 30 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

[6] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

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.

<u>OSBA and PSU PROPOSALS</u>

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

A. Yes. Mr. Knecht did not submit an independent analysis of the cost of equity. Instead, he opines that the Company's current rates provide a rate of return on common equity of 7.50% that he deems to be reasonable. He bases his proposal using returns previously awarded by the Commission in its rate case decision for the Electric Division of UGI Utilities and the alleged reduction in business risk granted to the Company by the Pennsylvania legislature.

Q. Does his proposal have merit?

A. Absolutely not. First, it is based on the false assumption that the risk premium implicit in the Electric Division of UGI Utilities rate case is static. As I have clearly demonstrated in my direct testimony, the risk premium is dynamic, in that it decreases as interest rates rise and increases as interest rates fall. As Mr. Knecht has indicated, interest rates have declined since the time of the UGI Utilities Electric Division rate case (see page 5 of OSBA St. 1). Hence, the risk premium today is higher when viewed in the context of dramatically lower interest rates.

Q. Mr. Knecht also opines that the anecdotal evidence suggests that utility risk is decreasing and that can be traced to the variety of rate mechanisms provided by

the Pennsylvania legislature (see footnote 4 of OSBA Statement No. 1). Is his assessment valid?

A. No. Many of the mechanisms listed by Mr. Knecht are already in place for many of the companies that comprise my Gas Group. Hence, whatever risk reducing attributes of these mechanisms, they are encompassed in the market derived cost equity results that I have reflected in my cost of equity recommendation. This is because investors are aware of these mechanisms and have incorporated them into the prices they set for the common stocks of these companies. To further adjust the cost of equity for these factors, as Mr. Knecht proposes, would double-count for the risk implications of these mechanisms. I also note that some of these mechanisms, such as the distribution system improvement charge and the fully projected future test year are designed to encourage significant expansion of plant improvements and that such expansion increases risk for utilities. Finally, while available to all Pennsylvania utilities, some of these mechanisms have not been implemented by CPA, e.g., rate decoupling. Hence, Mr. Knecht's proposal is inappropriate for CPA in this case.

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 pages 7 and 8 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.

<u>COST OF COMMON EQUITY - COMPANY SPECIFIC FACTORS</u>

Q. At page 32 of I&E Statement No. 2, Mr. Keller asserts that the "switching cost to move from one NGDC to another," will discourage customers from changing to another gas utility. Is this correct?

A. Only in part. The situation of overlapping service territories is unique to gas utilities operating in western Pennsylvania. Other than NiSource, who is the parent company of CPA, no other member of my Gas Group is faced with overlapping service territories that provide the opportunity of bypass from another utility. Hence, the risk faced by CPA is generally higher than most members of my Gas Group.

Q. Please refer to Mr. Keller's discussion (see pages 34-39) concerning the potential loss of the Company's WNA.

A. Mr. Keller seems to believe that the availability, or lack thereof, of the WNA will not affect the Company's risk. He is wrong in both regards. Loss of the WNA would materially increase the risk of CPA. Without the WNA or RNA, a return above that shown by the Gas Group would be required for CPA.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Keller, Mr. O'Donnell, and Mr. Knecht 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. Given the company-specific risk factors including CPA's operating risk, an opportunity to earn a cost of equity of 10.95%, inclusive of 20 basis points to recognize the effectiveness of the Company's management, is reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 3

Question No. OCA 3-015:

Please provide the CGP capital structure and associated embedded cost rates and tax gross-up factors for FY 2018, FY 2019 as well as each succeeding quarter post-FY 2019.

Response:

Please refer to OCA 3-015 Attachment A to this response.

December 2018

	Amount in Millions [1]	Percentage of Total [1]	Effective Cost Rates
Long Term Debt	705.5	42.82%	5.14% [2]
Short Term Debt	55.9	3.39%	2.42% [2]
Common Equity	886.4	53.79%	11.39% [3]
	1,647.8	100.00%	

December 2019

	Amount in Millions [1]	Percentage of Total [1]	Effective Cost Rates
Long Term Debt	785.5	42.84%	4.99% [2]
Short Term Debt	64.5	3.52%	2.46% [2]
Common Equity	983.4	53.64%	9.21% [3]
	1,833.4	100.00%	

March 2020

	Amount in Millions [1]	Percentage of Total [1]	Effective Cost Rates
Long Term Debt	895.5	43.02%	4.86% [2]
Short Term Debt	76.5	3.67%	2.30% [2]
Common Equity	1,109.9	53.31%	8.42% [3]
	2,081.9	100.00%	

[1] Reported in Schedule E of the Quarterly Earnings Report filed with the Commission.

[2] Reported in Schedule F of the Quarterly Earnings Report filed with the Commission.

3 Reported in Schedule D-1 of the Quarterly Earnings Report filed with the Commission. Schedule D-1 includes a income tax rate of 28.89% in the calculation to present the return on common equity including the tax effect of using debt costs.

Year	Gas Average Authorized ROE	A-rated Utility Bond Yields	Gas Equity Risk Premium
1984	15.31%	14.03%	1.28%
1985	14.75%	12.47%	2.28%
1986	13.46%	9.58%	3.88%
1987	12.74%	10.10%	2.64%
1988	12.85%	10.49%	2.36%
1989	12.88%	9.77%	3.11%
1990	12.68%	9.86%	2.82%
1991	12.45%	9.36%	3.09%
1992	12.02%	8.69%	3.33%
1993	11.37%	7.59%	3.78%
1994	11.24%	8.31%	2.93%
1995	11.44%	7.89%	3.55%
1996	11.12%	7.75%	3.37%
1997	11.30%	7.60%	3.70%
1998	11.51%	7.04%	4.47%
1999	10.74%	7.62%	3.12%
2000	11.34%	8.24%	3.10%
2001	10.96%	7.76%	3.20%
2002	11.17%	7.37%	3.80%
2003	10.99%	6.58%	4.41%
2004	10.63%	6.16%	4.47%
2005	10.41%	5.65%	4.76%
2006	10.40%	6.07%	4.33%
2007	10.22%	6.07%	4.15%
2008	10.39%	6.53%	3.86%
2009	10.22%	6.04%	4.18%
2010	10.15%	5.46%	4.69%
2011	9.92%	5.04%	4.88%
2012	9.94%	4.13%	5.81%
2013	9.68%	4.48%	5.20%
2014	9.78%	4.28%	5.50%
2015	9.60%	4.12%	5.48%
2016	9.54%	3.93%	5.61%
2017	9.72%	4.00%	5.72%
2018	9.59%	4.25%	5.34%
2019	9.68%	3.77%	5.91%
Averages:			
1984-2019			4.00%
2000-2019			4.72%
2010-2019			5.41%
2015-2019			5.61%

Exhibit No. 400
(Updated)

COLUMBIA GAS OF PENNSYLVANIA, INC.

Schedules to Accompany

The Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

and

Fair Rate of Return

August 26, 2020

COLUMBIA GAS OF PENNSYLVANIA, INC.
Index of Schedules

Columbia Gas of Pennsylvania, Inc.

Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.22%	4.73%	2.00%
Short Term Debt	3.59%	2.06%	0.07%
Total Debt	45.81%		2.07%
Common Equity	54.19%	10.95%	5.93%
Total	100.00%		8.00%

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
(10.41% ÷ 2.07%) 5.03 x

Post-tax coverage of interest expense
(8.00% ÷ 2.07%) 3.86 x

Columbia Gas of Pennsylvania, Inc.
Cost of Equity
as of July 31, 2020

												July 31, 2020 Three-Month Average	December 31, 2019 Six-Month Average	Difference
Discounted Cash Flow (DCF)					D_1/P_0 [1]	+	g [2]		+	lev. [3]	=	k		
Gas Group					3.39%	+	7.50%		+	2.03%	=	12.92%	11.91%	1.01%
Risk Premium (RP)							I [4]		+	RP [5]	=	k		
Gas Group							3.35%		+	6.75%	=	10.10%	10.50%	-0.40%
Capital Asset Pricing Model (CAPM)	Rf [6]	+	ß [7]	x (			Rm-Rf [8]	) +		size [9]	=	k		
Gas Group	1.75%	+	1.05	x (			9.26%	) +		1.02%	=	12.49%	10.19%	2.30%
Comparable Earnings (CE) [10]							Historical			Forecast		Average		
Comparable Earnings Group							12.8%			12.6%		12.70%	12.75%	-0.05%

References: [1] Schedule 07
[2] Schedule 09
[3] Schedule 10
[4] A-rated public utility bond yield comprised of a 1.75% risk-free rate of return (Schedule 13 page 2) and a yield spread of 1.60% (Schedule 11 page 3)
[5] Schedule 12 page 1
[6] Schedule 13 page 2
[7] Schedule 10
[8] Schedule 13 page 2
[9] Schedule 13 page 3
[10] Schedule 14 page 2

Columbia Gas of Pennsylvania, Inc.
Capitalization and Financial Statistics
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,768.9	$ 1,591.9	$ 1,361.1	$ 1,210.3	$ 1,098.5	
Short-Term Debt	$ 46.5	$ 51.5	$ 37.8	$ 33.4	$ 27.8	
Total Capital	$ 1,815.5	$ 1,643.4	$ 1,398.9	$ 1,243.7	$ 1,126.3	
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	44.4%	44.3%	46.0%	44.7%	45.1%	44.9%
Common Equity (1)	55.6%	55.7%	54.0%	55.3%	54.9%	55.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	45.8%	46.1%	47.4%	46.1%	46.5%	46.4%
Common Equity (1)	54.2%	53.9%	52.6%	53.9%	53.5%	53.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	10.4%	13.0%	9.4%	10.5%	11.3%	10.9%
Operating Ratio (2)	72.9%	72.9%	76.3%	73.3%	76.3%	74.3%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	4.18 x	4.52 x	4.21 x	4.63 x	4.75 x	4.46 x
Post-tax: All Interest Charges	3.48 x	3.96 x	3.01 x	3.28 x	3.37 x	3.42 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	4.16 x	4.49 x	4.18 x	4.61 x	4.73 x	4.43 x
Post-tax: All Interest Charges	3.46 x	3.93 x	2.99 x	3.26 x	3.35 x	3.40 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	1.0%	0.8%	1.1%	1.0%	0.7%	0.9%
Effective Income Tax Rate	21.9%	15.9%	37.2%	37.1%	36.8%	29.8%
Internal Cash Generation/Construction (4)	56.8%	66.1%	59.5%	66.7%	73.5%	64.5%
Gross Cash Flow/ Avg. Total Debt (5)	22.6%	23.9%	25.4%	28.4%	29.5%	26.0%
Gross Cash Flow Interest Coverage (6)	4.61 x	4.75 x	4.82 x	5.32 x	5.25 x	4.95 x

See Page 2 for Notes.

Columbia Gas of Pennsylvania, Inc.
Capitalization and Financial Statistics
2015-2019, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Company provided Financial Statements

Gas Group
Capitalization and Financial Statistics [1]
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 5,169.4	$ 4,698.4	$ 4,133.8	$ 3,746.8	$ 3,522.8	
Short-Term Debt	$ 553.3	$ 499.2	$ 402.2	$ 393.6	$ 259.5	
Total Capital	$ 5,722.7	$ 5,197.6	$ 4,536.0	$ 4,140.4	$ 3,782.3	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	26 x	20 x	22 x	22 x	19 x	22 x
Market/Book Ratio	222.4%	217.6%	224.2%	201.9%	187.7%	210.8%
Dividend Yield	2.7%	2.8%	2.6%	2.8%	3.0%	2.8%
Dividend Payout Ratio	72.5%	52.4%	71.1%	60.7%	67.7%	64.9%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	48.3%	47.9%	47.1%	45.0%	45.9%	46.8%
Preferred Stock	1.5%	1.0%	0.0%	0.1%	0.0%	0.5%
Common Equity [2]	50.3%	51.1%	52.9%	54.9%	54.0%	52.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.4%	53.4%	53.0%	50.5%	51.3%	52.3%
Preferred Stock	1.3%	0.9%	0.0%	0.1%	0.0%	0.5%
Common Equity [2]	45.3%	45.7%	47.0%	49.5%	48.7%	47.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	8.6%	10.0%	8.0%	9.2%	9.4%	9.0%
Operating Ratio [3]	83.6%	84.6%	84.1%	83.0%	85.0%	84.1%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.79 x	3.65 x	4.22 x	4.88 x	4.85 x	4.28 x
Post-tax: All Interest Charges	3.37 x	3.47 x	3.31 x	3.58 x	3.62 x	3.47 x
Overall Coverage: All Int. & Pfd. Div.	3.33 x	3.47 x	3.31 x	3.58 x	3.62 x	3.46 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.73 x	3.60 x	4.19 x	4.82 x	4.79 x	4.23 x
Post-tax: All Interest Charges	3.30 x	3.42 x	3.27 x	3.52 x	3.57 x	3.42 x
Overall Coverage: All Int. & Pfd. Div.	3.26 x	3.42 x	3.27 x	3.52 x	3.57 x	3.41 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.0%	3.2%	-5.2%	2.3%	2.4%	1.1%
Effective Income Tax Rate	15.0%	15.6%	39.7%	33.6%	32.6%	27.3%
Internal Cash Generation/Construction [5]	48.7%	46.7%	59.5%	71.6%	71.0%	59.5%
Gross Cash Flow/ Avg. Total Debt [6]	18.3%	18.4%	21.4%	23.7%	22.8%	20.9%
Gross Cash Flow Interest Coverage [7]	6.24 x	6.05 x	6.69 x	7.35 x	6.96 x	6.66 x
Common Dividend Coverage [8]	3.86 x	3.63 x	4.21 x	4.60 x	4.48 x	4.16 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2015-2019, Inclusive

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group “Natural Gas Utility,” they are not currently the target of a publicly-announced merger or acquisition, and after eliminating UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
ATO	Atmos Energy Corp.	A1	A	NYSE	0.80
CPK	Chesapeake Utilities Corp.	NAIC "1"		NYSE	0.75
NJR	New Jersey Resources Corp.	A1	BBB+	NYSE	0.90
NI	NiSource Inc.	Baa2	BBB+	NYSE	0.85
NWN	Northwest Natural Holding Compa	Baa1	A+	NYSE	0.80
OGS	ONE Gas, Inc.	A2	A	NYSE	0.80
SJI	South Jersey Industries, Inc.	A3	BBB	NYSE	0.95
SWX	Southwest Gas Holdings, Inc.	A3	A-	NYSE	0.90
SR	Spire, Inc.	A1	A-	NYSE	0.80
	Average	A2	A-		0.84

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody’s Investors Service
Standard & Poor’s Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 36,567.1	$ 32,871.6	$ 30,827.6	$ 29,173.1	$ 26,655.9	
Short-Term Debt	$ 1,221.9	$ 1,420.3	$ 1,076.1	$ 1,032.2	$ 875.5	
Total Capital	$ 37,789.0	$ 34,291.9	$ 31,903.7	$ 30,205.3	$ 27,531.4	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	20 x	21 x	21 x	21 x	18 x	20 x
Market/Book Ratio	220.8%	204.7%	214.4%	196.0%	181.1%	203.4%
Dividend Yield	3.2%	3.5%	3.3%	3.5%	3.6%	3.4%
Dividend Payout Ratio	62.7%	71.7%	74.4%	74.6%	68.8%	70.4%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.7%	55.0%	56.8%	56.6%	54.7%	55.9%
Preferred Stock	2.2%	2.5%	1.4%	1.9%	1.6%	1.9%
Common Equity [2]	41.1%	42.5%	41.8%	41.6%	43.8%	42.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.2%	57.0%	58.4%	58.2%	56.1%	57.6%
Preferred Stock	2.1%	2.4%	1.4%	1.8%	1.5%	1.8%
Common Equity [2]	39.7%	40.7%	40.3%	40.1%	42.4%	40.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.3%	10.3%	10.8%	9.7%	9.7%	10.2%
Operating Ratio [3]	79.3%	79.8%	77.0%	78.2%	79.7%	78.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.05 x	2.94 x	3.42 x	3.38 x	3.80 x	3.32 x
Post-tax: All Interest Charges	3.10 x	2.59 x	2.86 x	2.55 x	2.79 x	2.78 x
Overall Coverage: All Int. & Pfd. Div.	3.04 x	2.55 x	2.84 x	2.52 x	2.75 x	2.74 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.95 x	2.84 x	3.31 x	3.28 x	3.70 x	3.22 x
Post-tax: All Interest Charges	3.00 x	2.48 x	2.75 x	2.44 x	2.69 x	2.67 x
Overall Coverage: All Int. & Pfd. Div.	2.94 x	2.44 x	2.73 x	2.41 x	2.65 x	2.63 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	5.8%	7.3%	7.3%	6.5%	5.5%	6.5%
Effective Income Tax Rate	12.2%	19.0%	28.2%	29.0%	32.5%	24.2%
Internal Cash Generation/Construction [5]	66.0%	75.7%	78.7%	78.0%	71.9%	74.1%
Gross Cash Flow/ Avg. Total Debt [6]	17.5%	17.4%	19.9%	20.5%	20.0%	19.1%
Gross Cash Flow Interest Coverage [7]	4.97 x	4.98 x	5.57 x	5.54 x	5.41 x	5.29 x
Common Dividend Coverage [8]	5.56 x	4.80 x	4.33 x	4.31 x	4.24 x	4.65 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2015-2019, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating [1] Moody's	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.60
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.55
American Electric Power	AEP	Baa1	A-	NYSE	0.55
American Water Works	AWK	Baa1	A	NYSE	0.55
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	0.80
CMS Energy	CMS	A3	A-	NYSE	0.50
Consolidated Edison	ED	Baa1	A-	NYSE	0.45
Dominion Energy	D	A2	BBB+	NYSE	0.55
DTE Energy Co.	DTE	A2	A-	NYSE	0.55
Duke Energy	DUK	A1	A-	NYSE	0.50
Edison Int'l	EIX	Baa2	BBB	NYSE	0.55
Entergy Corp.	ETR	Baa1	A-	NYSE	0.60
Evergy, Inc.	EVRG	Baa1	A	NYSE	NMF
Eversource	ES	A3	A	NYSE	0.55
Exelon Corp.	EXC	A3	BBB+	NYSE	0.65
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	0.65
NextEra Energy Inc.	NEE	A1	A	NYSE	0.55
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.55
NRG Energy Inc.	NRG	Ba1	BB	NYSE	1.25
Pinnacle West Capital	PNW	A2	A-	NYSE	0.50
PPL Corp.	PPL	A3	A-	NYSE	0.70
Public Serv. Enterprise Inc.	PEG	A2	A-	NYSE	0.65
Sempra Energy	SRE	Baa1	BBB+	NYSE	0.70
Southern Co.	SO	Baa1	A-	NYSE	0.50
WEC Energy Corp.	WEC	A2	A-	NYSE	0.50
Xcel Energy Inc	XEL	A2	A-	NYSE	0.50
Average for S&P Utilities		A3	A-		0.60

Note: [1] Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Columbia Gas of Pennsylvania, Inc.
Investor-provided Capitalization
Actual at November 30, 2019, Estimated at November 30, 2020, and Estimated at December 31, 2021

	Actual at November 30, 2019		Estimated at November 30, 2020		Estimated at December 31, 2021	
	Amount Outstanding	Ratios	Amount Outstanding	Ratios	Amount Outstanding	Ratios
Long Term Debt	$ 785,515,000	43.74%	$ 895,515,000	43.00%	$ 975,515,000	42.22%
Common Stock Equity						
Common Stock	45,128,000		45,128,000		45,128,000	
Additional Paid in Capital	52,889,827		107,889,827		107,889,827	
Retained Earnings	853,475,761		950,868,301		1,099,269,678	
Total Common Equity	951,493,588	52.99%	1,103,886,128	53.00%	1,252,287,505	54.19%
Total Permanent Capital	$1,737,008,588	96.73%	$1,999,401,128	96.00%	$2,227,802,505	96.41%
Short Term Debt (Twelve month average)	58,764,658	3.27%	83,375,269	4.00%	82,945,831	3.59%
Total Capital Employed	$1,795,773,246	100.00%	$2,082,776,397	100.00%	$2,310,748,336	100.00%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Actual at November 30, 2019

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	
November 1, 2006	6.015%	20,000,000	1,203,000	
December 14, 2007	6.865%	58,000,000	3,981,700	
December 16, 2010	6.020%	28,000,000	1,685,600	
March 28, 2012	5.355%	30,000,000	1,606,500	
March 28, 2012	5.890%	35,000,000	2,061,500	
November 28, 2012	5.260%	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	
Total Long-Term Debt		785,515,000	39,219,688	4.99%
Short Term Debt (Twelve month average)	2.17%	58,764,658	1,275,193	
Total Debt		$ 844,279,658	$ 40,494,881	4.80%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Estimated at November 30, 2020

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	
November 1, 2006	6.015%	20,000,000	1,203,000	
December 14, 2007	6.865%	58,000,000	3,981,700	
December 16, 2010	6.020%	28,000,000	1,685,600	
March 28, 2012	5.355%	30,000,000	1,606,500	
March 28, 2012	5.890%	35,000,000	2,061,500	
November 28, 2012	5.260%	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	
Total Long-Term Debt		895,515,000	43,478,448	4.86%
Short Term Debt (Twelve month average)	2.00%	83,375,269	1,667,505	
Total Debt		$ 978,890,269	$ 45,145,953	4.61%

Source of information: Company provided data

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Estimated at December 30, 2021

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	3.8716%	100,000,000	3,871,600	
Total Long-Term Debt		975,515,000	46,147,048	4.73%
Short Term Debt (Twelve month average)	2.06%	82,945,831	1,708,684	
Total Debt		$ 1,058,460,831	$ 47,855,732	4.52%

Source of information: Company provided data

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending July 2020

Company	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	1.91%	1.85%	2.05%	2.15%	2.06%	1.97%	2.23%	2.32%	2.27%	2.24%	2.32%	2.18%			
Chesapeake Utilities Corp (CPK)	1.72%	1.70%	1.71%	1.78%	1.69%	1.69%	1.90%	1.89%	2.01%	1.96%	2.10%	2.09%			
New Jersey Resources Corporation (NJR)	2.75%	2.77%	2.88%	2.96%	2.81%	3.04%	3.57%	3.69%	3.72%	3.59%	3.83%	4.05%			
NiSource Inc (NI)	2.71%	2.69%	2.85%	3.03%	2.89%	2.86%	3.11%	3.38%	3.37%	3.54%	3.72%	3.44%			
Northwest Natural Holding Company (NWN)	2.67%	2.68%	2.75%	2.78%	2.60%	2.60%	2.91%	3.11%	2.93%	2.99%	3.44%	3.57%			
ONE Gas Inc (OGS)	2.19%	2.09%	2.16%	2.25%	2.14%	2.30%	2.63%	2.59%	2.72%	2.58%	2.81%	2.87%			
South Jersey Industries Inc (SJI)	3.59%	3.50%	3.69%	3.81%	3.59%	3.85%	4.41%	4.73%	4.15%	4.20%	4.73%	5.09%			
Southwest Gas Holdings Inc (SWX)	2.39%	2.40%	2.51%	2.88%	2.88%	2.91%	3.38%	3.15%	3.03%	3.01%	3.32%	3.30%			
Spire Inc. (SR)	2.81%	2.72%	2.97%	3.24%	2.99%	2.97%	3.34%	3.35%	3.43%	3.44%	3.80%	4.06%			
Average	**2.53%**	**2.49%**	**2.62%**	**2.76%**	**2.63%**	**2.69%**	**3.05%**	**3.13%**	**3.07%**	**3.06%**	**3.34%**	**3.41%**	**2.90%**	**3.18%**	**3.27%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://performance.morningstar.com/stock/performance-return

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0
	3.27%	1.037500	3.39%
Discrete	D_0/P_0	Adj.	D_1/P_0
	3.27%	1.046451	3.42%
Quarterly	D_0/P_0	Adj.	D_1/P_0
	0.8175%	1.018245	3.37%
Average			3.39%
Growth rate			7.50%
K			10.89%

$$K = \frac{D_o(1+g)^o + D_o(1+g)^o + D_o(1+g)^1 + D_o(1+g)^1}{P_o} + g$$

$$K = \frac{D_o(1+g)^{.25} + D_o(1+g)^{.50} + D_o(1+g)^{.75} + D_o(1+g)^{1.00}}{P_o} + g$$

$$K = \left[\left(1 + \frac{D_o(1+g)^{.25}}{P_o}\right)^4 - 1\right] + g$$

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		**Dividends per Share**		**Book Value per Share**		**Cash Flow per Share**	
	Value Line		Value Line		Value Line		Value Line	
Gas Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
Atmos Energy Corp (ATO)	9.50%	7.50%	6.50%	4.00%	8.50%	6.50%	7.00%	5.50%
Chesapeake Utilities Corp (CPK)	8.00%	9.00%	6.50%	5.50%	10.50%	9.50%	7.00%	10.00%
New Jersey Resources Corporation (NJR)	6.00%	7.00%	6.50%	7.00%	8.50%	7.00%	7.50%	7.50%
NiSource Inc (NI)	-8.00%	-1.00%	-5.00%	-2.00%	-7.00%	-3.00%	-5.00%	-2.00%
Northwest Natural Holding Company (NWN)	-17.00%	-11.00%	0.50%	2.00%	-0.50%	1.50%	-5.50%	-3.00%
ONE Gas Inc (OGS)	9.50%	-	17.00%	-	2.50%	-	7.00%	-
South Jersey Industries Inc (SJI)	-2.50%	1.50%	6.00%	8.00%	6.00%	6.50%	3.50%	5.00%
Southwest Gas Holdings Inc (SWX)	4.50%	8.00%	9.50%	8.50%	6.50%	6.00%	1.50%	4.00%
Spire Inc. (SR)	9.50%	3.50%	5.50%	4.00%	7.00%	7.00%	13.00%	5.50%
Average	2.17%	3.06%	5.89%	4.63%	4.67%	5.13%	4.00%	4.06%

Source of Information: Value Line Investment Survey, May 29, 2020

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

			Value Line				
Gas Group	**I/B/E/S First Call**	**Zacks**	**Earnings Per Share**	**Dividends Per Share**	**Book Value Per Share**	**Cash Flow Per Share**	**Percent Retained to Common Equity**
Atmos Energy Corp (ATO)	7.15%	7.20%	7.00%	7.50%	7.50%	5.50%	4.50%
Chesapeake Utilities Corp (CPK)	4.74%	NA	9.00%	8.50%	10.00%	8.50%	5.50%
New Jersey Resources Corporatior	6.00%	6.00%	2.00%	6.00%	8.50%	2.00%	3.00%
NiSource Inc (NI)	3.49%	5.30%	13.50%	7.50%	5.00%	8.00%	4.50%
Northwest Natural Holding Compar	3.90%	3.90%	26.50%	0.50%	2.00%	9.00%	5.00%
ONE Gas Inc (OGS)	5.00%	5.50%	6.50%	7.50%	4.00%	6.50%	4.00%
South Jersey Industries Inc (SJI)	10.30%	10.30%	12.50%	3.50%	5.50%	6.00%	5.50%
Southwest Gas Holdings Inc (SWX)	8.20%	6.00%	8.00%	4.00%	6.00%	7.00%	5.50%
Spire Inc. (SR)	4.67%	4.80%	5.50%	5.00%	8.50%	5.50%	3.00%
Average	5.94%	6.13%	10.06%	5.56%	6.33%	6.44%	4.50%

Source of Information : Yahoo Finance, Jume 30, 2020
Zacks, Jume 30, 2020
Value Line Investment Survey, May 29, 2020

Gas Group
Financial Risk Adjustment

		ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year		09/30/19	12/31/19	09/30/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	09/30/19	
Capitalization at Fair Values											
	Debt(D)	4,216,249	505,000	1,568,864	8,764,400	957,268	1,500,000	2,730,000	2,672,077	2,373,400	2,809,695
	Preferred(P)	0	0	0	0	0	0	0	0	0	0
	Equity(E)	13,349,252	1,571,974	3,913,860	10,638,657	2,246,701	4,937,853	3,047,159	4,178,915	4,246,604	5,347,886
	Total	17,565,501	2,076,974	5,482,724	19,403,057	3,203,969	6,437,853	5,777,159	6,850,992	6,620,004	8,157,581
Capital Structure Ratios											
	Debt(D)	24.00%	24.31%	28.61%	45.17%	29.88%	23.30%	47.26%	39.00%	35.85%	33.04%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Equity(E)	76.00%	75.69%	71.39%	54.83%	70.12%	76.70%	52.74%	61.00%	64.15%	66.96%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock											
	Issued	119,338.925	16,403.776	89,998.788	382,135.680	30,472.000	52,771.749	92,394.155	55,007.433	50,973.515	
	Treasury	0.000	0.000	2,185.013	0.000	0.000	0.000	0.000	0.000	0.000	
	Outstanding	119,338.925	16,403.776	87,813.775	382,135.680	30,472.000	52,771.749	92,394.155	55,007.433	50,973.515	
	Market Price	$111.86	$95.83	$44.57	$27.84	$73.73	$93.57	$32.98	$75.97	$83.31	
Capitalization at Carrying Amounts											
	Debt(D)	3,560,000	486,600	1,442,845	7,869,600	881,064	1,300,000	2,540,000	2,463,994	2,122,600	2,518,523
	Preferred(P)	0	0	0	0	0	0	0	0	0	0
	Equity(E)	5,750,223	561,577	1,551,717	5,986,700	865,999	2,129,390	1,423,785	2,505,914	2,543,000	2,590,923
	Total	9,310,223	1,048,177	2,994,562	13,856,300	1,747,063	3,429,390	3,963,785	4,969,908	4,665,600	5,109,445
Capital Structure Ratios											
	Debt(D)	38.24%	46.42%	48.18%	56.79%	50.43%	37.91%	64.08%	49.58%	45.49%	48.57%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Equity(E)	61.76%	53.58%	51.82%	43.21%	49.57%	62.09%	35.92%	50.42%	54.51%	51.43%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.80	0.75	0.90	0.85	0.80	0.80	0.95	0.90	0.80	0.84

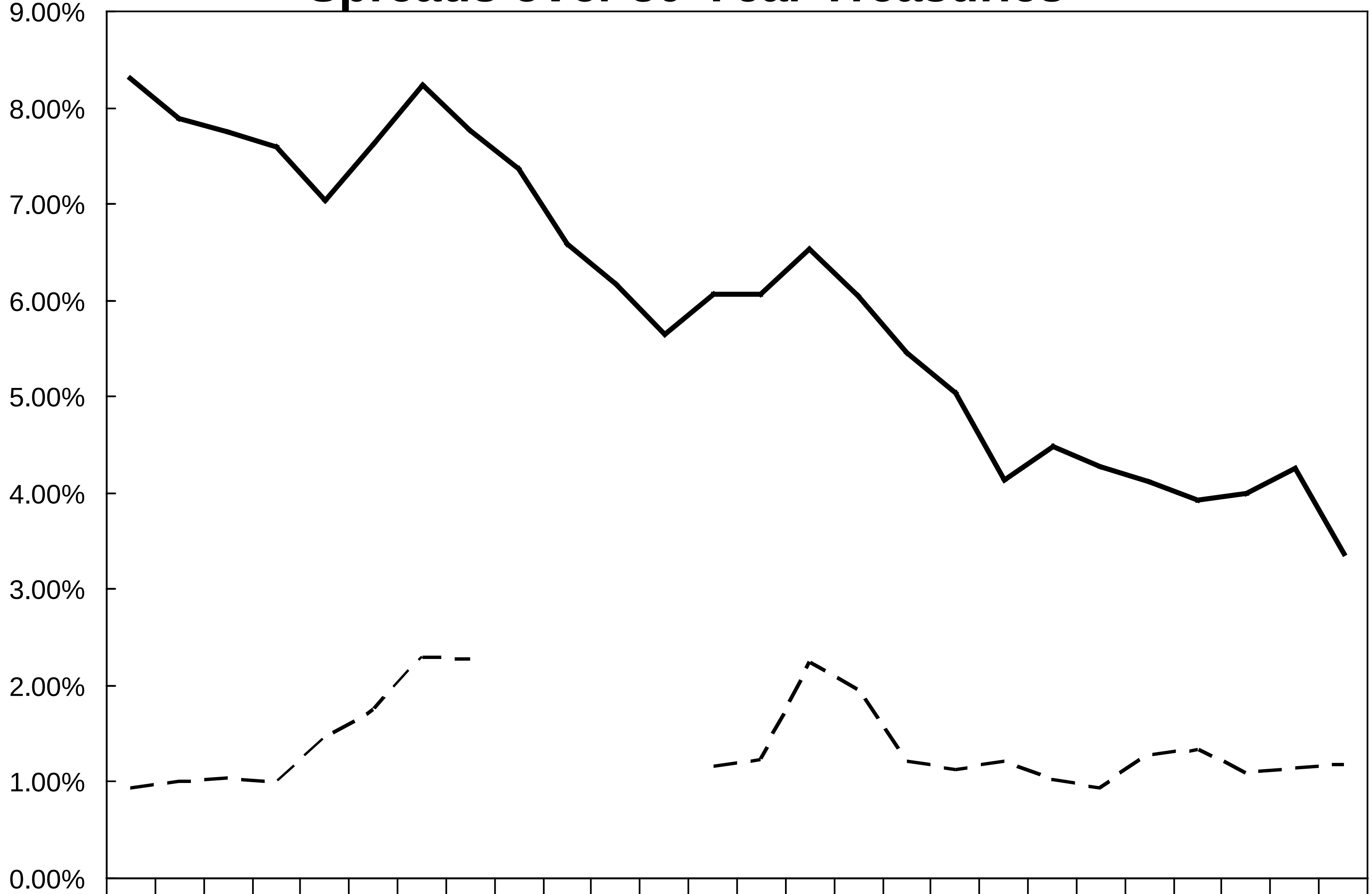
Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.84	=	Bu	[1+	(1-0.21)	0.4934	+	0.0000	]
	0.84	=	Bu	[1+	0.79	0.4934	+	0.0000	]
	0.84	=	Bu	1.3898					
	0.60	=	Bu						
Hamada	Bl	=	0.60	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.60	[1+	0.79	0.9443	+	0.0000	]
	Bl	=	0.60	1.7460					
	Bl	=	1.05						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	-	d	)	P	/	E
	8.67%	=	10.89%	-	(((	8.67%	-	2.98%	)	0.79	)	33.04%	/	66.96%	-	8.67%	-	5.68%	)	0.00%	/	66.96%
	8.67%	=	10.89%	-	(((	5.69%			)	0.79	)	0.4934			-	2.99%			)	0.0000		
	8.67%	=	10.89%	-	((	4.50%					)	0.4934			-	2.99%			)	0		
	8.67%	=	10.89%	-		2.22%									-	0.00%						
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	-	d	)	P	/	E
	12.92%	=	8.67%	+	(((	8.67%	-	2.98%	)	0.79	)	48.57%	/	51.43%	+	8.67%	-	5.68%	)	0.00%	/	51.43%
	12.92%	=	8.67%	+	(((	5.69%			)	0.79	)	0.9443			+	2.99%			)	0.0000		
	12.92%	=	8.67%	+	((	4.50%					)	0.9443			+	2.99%			)	0		
	12.92%	=	8.67%	+		4.25%									+	0.00%						

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2015-2019
and the Twelve Months Ended July 2020

Years	Aa Rated	A Rated	Baa Rated	Average
2015	4.00%	4.12%	5.03%	4.38%
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
Five-Year Average	3.85%	4.01%	4.59%	4.15%
Months				
Aug-20	3.17%	3.29%	3.63%	3.36%
Sep-20	3.24%	3.37%	3.71%	3.44%
Oct-20	3.24%	3.39%	3.72%	3.45%
Nov-20	3.25%	3.43%	3.76%	3.48%
Dec-20	3.22%	3.40%	3.73%	3.45%
Jan-20	3.12%	3.29%	3.60%	3.34%
Feb-20	2.96%	3.11%	3.42%	3.16%
Mar-20	3.30%	3.50%	3.96%	3.59%
Apr-20	2.93%	3.19%	3.82%	3.31%
May-20	2.89%	3.14%	3.63%	3.22%
Jun-20	2.80%	3.07%	3.44%	3.10%
Jul-20	2.46%	2.74%	3.09%	2.77%
Twelve-Month Average	3.05%	3.24%	3.63%	3.31%
Six-Month Average	2.89%	3.13%	3.56%	3.19%
Three-Month Average	2.72%	2.98%	3.39%	3.03%

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.37
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.34	1.10	1.14	1.19

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Average:	12-months		1.40%
	6-months		1.65%
	3-months		1.59%

Common Equity Risk Premiums
Years 1926-2019

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	11.92%	5.22%	6.70%	2.88%
Average Across All Interest Rates	12.09%	6.40%	5.69%	4.99%
High Interest Rates	12.26%	7.57%	4.69%	7.09%

Source of Information: 2020 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2015-2019
and the Twelve Months Ended July 2020

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2015	0.32%	0.69%	1.03%	1.53%	1.89%	2.14%	2.55%	2.84%
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
Five-Year Average	1.30%	1.49%	1.64%	1.90%	2.12%	2.27%	2.57%	2.81%
Months								
Aug-19	1.77%	1.57%	1.51%	1.49%	1.55%	1.63%	1.91%	2.12%
Sep-19	1.80%	1.65%	1.59%	1.57%	1.64%	1.70%	1.97%	2.16%
Oct-19	1.61%	1.55%	1.53%	1.53%	1.62%	1.71%	2.00%	2.19%
Nov-19	1.57%	1.61%	1.61%	1.64%	1.74%	1.81%	2.13%	2.28%
Dec-19	1.55%	1.61%	1.63%	1.68%	1.79%	1.86%	2.16%	2.30%
Jan-20	1.53%	1.52%	1.52%	1.56%	1.67%	1.76%	2.07%	2.22%
Feb-20	1.41%	1.33%	1.31%	1.32%	1.42%	1.50%	1.81%	1.97%
Mar-20	0.33%	0.45%	0.50%	0.59%	0.78%	0.87%	1.26%	1.46%
Apr-20	0.18%	0.22%	0.28%	0.39%	0.55%	0.66%	1.06%	1.27%
May-20	0.16%	0.17%	0.22%	0.34%	0.53%	0.67%	1.12%	1.38%
Jun-20	0.18%	0.19%	0.22%	0.34%	0.55%	0.73%	1.27%	1.49%
Jul-20	0.15%	0.15%	0.17%	0.28%	0.46%	0.62%	1.09%	1.31%
Twelve-Month Average	1.02%	1.00%	1.01%	1.06%	1.19%	1.29%	1.65%	1.85%
Six-Month Average	0.40%	0.42%	0.45%	0.54%	0.72%	0.84%	1.27%	1.48%
Three-Month Average	0.16%	0.17%	0.20%	0.32%	0.51%	0.67%	1.16%	1.39%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated June 1, 2020 and July 31, 2020

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2020	Third	0.2%	0.2%	0.4%	0.7%	1.4%	2.4%	3.6%
2020	Fourth	0.2%	0.3%	0.4%	0.8%	1.5%	2.5%	3.7%
2021	First	0.2%	0.3%	0.5%	0.9%	1.6%	2.6%	3.8%
2021	Second	0.3%	0.3%	0.6%	1.0%	1.7%	2.7%	3.8%
2021	Third	0.3%	0.4%	0.7%	1.1%	1.8%	2.7%	3.9%
2021	Fourth	0.4%	0.5%	0.8%	1.2%	1.9%	2.8%	3.9%
Long-range CONSENSUS								
2021		0.4%	0.5%	0.7%	1.2%	1.8%	2.8%	4.1%
2022		0.7%	0.9%	1.1%	1.5%	2.2%	3.2%	4.5%
2023		1.3%	1.5%	1.7%	2.1%	2.7%	3.6%	4.9%
2024		1.8%	2.0%	2.2%	2.5%	3.1%	4.0%	5.2%
2025		2.1%	2.3%	2.5%	2.7%	3.3%	4.2%	5.3%
2026		2.3%	2.5%	2.7%	2.9%	3.5%	4.3%	5.4%
Averages:								
	2022-2026	1.7%	1.8%	2.0%	2.3%	3.0%	3.9%	5.0%
	2027-2031	2.6%	2.7%	2.9%	3.1%	3.8%	4.6%	5.7%

Measures of the Market Premium

Value Line Return					
As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
31-Jul-20	2.4%	+	12.47%	=	14.87%

DCF Result for the S&P 500 Composite							
D/P	(	1+.5g	)	+	g	=	k
1.74%	(	1.0290	)	+	5.80%	=	7.59%

Summary			
Value Line			14.87%
S&P 500			7.59%
Average			11.23%
Risk-free Rate of Return (Rf)			1.75%
Forecast Market Premium			9.48%
Historical Market Premium			
Low Interest Rates	(Rm)	(Rf)	
1926-2019 Arith. mean	11.92%	2.88%	9.04%
Average - Forecast/Historical			9.26%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach

Using Non-Utility Companies with
Timeliness of 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 70 to 95; Betas of .75 to .95; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
ANSYS Inc	Computer Software	3	2	A	90	0.90	3
Brady Corp	Diversified Co.	3	3	B++	80	0.95	3
Brown Forman Corp (Class B)	Beverage	3	1	A	95	0.85	2
Caseys General Stores Inc	Retail/Wholesale Food	3	3	B+	85	0.80	3
Commerce Bancshares Inc	Bank (Midwest)	3	1	A	90	0.90	2
Cooper Companies Inc	Med Supp Non-Invasive	3	2	A	85	0.95	3
EchoStar Corporation	Cable TV	3	3	B+	75	0.90	3
Ennis Inc.	Office Equip/Supplies	3	3	B++	80	0.80	3
ESCO Technologies Inc	Diversified Co.	3	3	B+	90	0.95	2
Exponent Inc.	Information Services	3	3	B+	90	0.85	2
F5 Networks	Telecom. Equipment	3	3	A	75	0.90	3
FirstCash Inc.	Financial Svcs. (Div.)	3	3	B++	85	0.80	2
FLIR Systems Inc	Electrical Equipment	3	3	B++	70	0.95	3
Forrester Research Inc	Information Services	3	3	B+	70	0.95	3
Franklin Electric Co Inc	Electrical Equipment	3	3	A	70	0.95	2
Gentex Corp	Auto Parts	3	3	B++	85	0.95	2
Guidewire Software	Computer Software	3	3	B+	70	0.90	2
Hanover Insurance Group Inc	Insurance (Prop/Cas.)	3	2	B++	95	0.95	3
J and J Snack Foods Corp	Food Processing	4	1	A+	90	0.90	3
J B Hunt Transport Services Inc	Trucking	3	2	A+	85	0.95	2
Mettler Toledo International Inc	Precision Instrument	3	2	B++	90	0.95	3
Motorola Solutions Inc	Telecom. Equipment	3	2	B++	90	0.90	3
MSC Industrial Direct Co Inc	Machinery	3	2	A	75	0.95	3
Old National Bancorp	Bank (Midwest)	3	3	B+	80	0.95	3
Premier Inc.	Healthcare Information	3	3	B++	75	0.75	3
Quest Diagnostics Inc	Medical Services	3	2	B++	90	0.95	3
Salesforce Com Inc	E-Commerce	3	3	B++	80	0.85	2
Sensient Technologies Corp	Food Processing	3	3	B++	95	0.90	3
Stepan Company	Chemical (Specialty)	3	3	B++	70	0.85	3
Tetra Tech	Environmental	3	3	B++	85	0.90	3
Vail Resorts	Hotel/Gaming	3	3	B+	85	0.90	3
Walgreens Boots	Pharmacy Services	3	2	A+	85	0.80	3
Walt Disney Co	Entertainment	3	3	A	95	0.95	3
Werner Enterprises Inc	Trucking	3	3	B++	80	0.80	2
Average		3	3		83	0.90	3
Gas Group	Average	3	2	A	88	0.84	3

Source of Information: Value Line Investment Survey for Windows, August 2020

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2015-2019 and
Projected 3-5 Year Returns

Company	2015	2016	2017	2018	2019	Average	Projected 2023-25
ANSYS Inc	14.3%	14.6%	15.5%	19.4%	16.4%	16.0%	17.0%
Brady Corp	11.1%	13.3%	13.7%	14.9%	15.4%	13.7%	14.0%
Brown Forman Corp (Class B)	45.3%	48.8%	56.7%	50.7%	41.9%	48.7%	60.0%
Caseys General Stores Inc	20.9%	14.9%	11.2%	14.5%	16.1%	15.5%	12.5%
Commerce Bancshares Inc	11.2%	11.0%	11.8%	14.8%	13.4%	12.4%	8.0%
Cooper Companies Inc	7.6%	10.1%	11.7%	10.3%	12.9%	10.5%	13.0%
EchoStar Corporation	4.0%	4.6%	2.2%	0.9%	NMF	2.9%	3.5%
Ennis Inc.	12.0%	10.5%	12.5%	12.9%	13.0%	12.2%	12.5%
ESCO Technologies Inc	7.1%	8.3%	8.6%	9.0%	9.9%	8.6%	10.5%
Exponent Inc.	16.6%	17.4%	14.3%	23.0%	23.5%	19.0%	30.0%
F5 Networks	27.7%	30.9%	34.2%	35.3%	24.3%	30.5%	19.0%
FirstCash Inc.	14.1%	4.1%	7.9%	11.6%	12.2%	10.0%	12.0%
FLIR Systems Inc	13.4%	12.5%	13.7%	16.6%	16.2%	14.5%	15.5%
Forrester Research Inc	16.1%	16.5%	15.8%	16.5%	19.6%	16.9%	14.0%
Franklin Electric Co Inc	13.2%	12.8%	12.5%	14.6%	12.3%	13.1%	13.5%
Gentex Corp	18.5%	18.2%	18.0%	23.5%	21.9%	20.0%	23.0%
Guidewire Software	1.4%	1.9%	2.4%	NMF	1.3%	1.8%	1.5%
Hanover Insurance Group Inc	9.8%	6.5%	6.8%	9.9%	11.4%	8.9%	10.0%
J and J Snack Foods Corp	11.7%	11.9%	11.6%	11.1%	11.4%	11.5%	12.5%
J B Hunt Transport Services Inc	32.9%	30.6%	22.6%	29.7%	24.9%	28.1%	18.5%
Mettler Toledo International Inc	60.8%	88.4%	81.9%	83.6%	NMF	78.7%	NMF
Motorola Solutions Inc	-	-	-	23.2%	NMF	23.2%	NMF
MSC Industrial Direct Co Inc	17.5%	21.1%	18.7%	20.8%	20.0%	19.6%	22.0%
Old National Bancorp	7.8%	7.4%	6.0%	7.1%	8.4%	7.3%	9.0%
Premier Inc.	21.6%	19.7%	18.1%	21.2%	20.9%	20.3%	20.0%
Quest Diagnostics Inc	14.8%	15.9%	16.2%	16.8%	15.9%	15.9%	15.5%
Salesforce Com Inc	NMF	2.4%	1.4%	7.1%	0.4%	2.8%	7.0%
Sensient Technologies Corp	16.7%	17.2%	17.7%	18.3%	14.2%	16.8%	17.0%
Stepan Company	13.6%	13.6%	12.4%	14.4%	11.6%	13.1%	15.0%
Tetra Tech	11.9%	12.8%	13.3%	15.4%	17.8%	14.2%	17.0%
Vail Resorts	13.0%	17.1%	13.4%	23.9%	20.1%	17.5%	25.0%
Walgreens Boots	13.2%	16.8%	20.0%	23.0%	23.5%	19.3%	17.5%
Walt Disney Co	18.8%	21.7%	21.7%	25.8%	11.7%	19.9%	11.0%
Werner Enterprises Inc	13.2%	8.0%	7.8%	13.6%	15.0%	11.5%	11.5%
Average						17.5%	15.9%
Average (excluding companies with values >20%)						12.8%	12.6%

Comparable Earnings Approach

Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

Statement No. 8SR

COLUMBIA GAS OF PENNSYLVANIA, INC.

Surrebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

DOCKET NO. R-2020-3018835

September 16, 2020

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 April 24, 2020 and rebuttal testimony, CPA Statement No. 8R, on August 26, 2020.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the rebuttal testimony submitted by Mr. Robert D. Knecht, a witness appearing on behalf of the Office of Small Business Advocate ("OSBA") (OSBA St. 1-R).

Q. Why are you submitting surrebuttal testimony to Mr. Knecht when he has rebutted the testimony of OCA witness O'Donnell?

A. While calling his testimony rebuttal, Mr. Knecht is further challenging the Company's return on equity proposal. So, while he may be complaining that Mr. O'Donnell's proposed return on equity is too high, he is making a collateral attack on the Company's position.

Q. Do you believe, as Mr. Knecht has asserted, that Mr. O'Donnell calculations of the cost of equity contains a material bias in favor of utility shareholders?

A. Absolutely not. As I demonstrated in my rebuttal testimony, see Columbia Statement No. 8R, Mr. O'Donnell seriously understated the return that investors both expect and require.

Q. Mr. Knecht spends a great deal of his rebuttal to Mr. O'Donnell on returns previously determined in public utility rate cases and points out that those determinations have not adequately tracked the decline in interest rates. Are these

observations by Mr. Knecht valid?

A. No. As I clearly demonstrated in both my direct and rebuttal testimony, there is an inverse relationship between the risk premium associated with the cost of equity and interest rates. That is to say, as interest rates decline the risk premium increases, and vice-versa. Mr. Knecht's argument that the returns should track the decline in interest rates is clearly false. This applies to both Mr. Knecht's graph at Figure IEc-1 and to his citation to the UGI Electric rate case decision by the Commission.

Q. Mr. Knecht claims that the circularity implied in the application of the DCF is a contributing factor to the elevated return produced by this model of the cost of equity. Do you agree?

A. Yes, in part. I likewise noted the circularity implicit in the DCF model in my direct testimony (see page 19 of Statement No. 8). However, I do not agree that any circularity necessarily produces elevated returns. While circularity might influence investors' expectations of the growth that a utility might realize, assuming that the utility could actually achieve the returns that regulators authorize, it does not alter their required returns because they are influenced by alternative investment opportunities.

Q. Mr. Knecht's second concern seems to be that natural gas as an energy source will gradually give way to alternative energy resources so that the growth rate used in the DCF model cannot be sustainable. Is this concern valid?

A. No. For this to be true, Mr. Knecht must believe that sophisticated investors are naïve and are uninformed about this prospect. But, Mr. Knecht has provided no empirical support for his proposition. Rather, there is a commitment on the part of public utilities and their investors to the business through substantial investment in natural gas infrastructure that has 30 to 50 years of useful life in rendering an essential energy source to Pennsylvania customers. Mr. Knecht seeks to buttress his argument by assuming a two-step DCF growth rate hypothetical, but the Commission has never ascribed to a multistage DCF analysis that Mr. Knecht's example implies. While the DCF model may assume a perpetual growth component, in fact the data used reflects shorter term, 5-10 year growth, which is the data investors rely on.

Q. Has Mr. Knecht also artificially altered the CAPM results that produce a distorted result?

A. Yes. Mr. Knecht has submitted a CAPM calculation that unwinds the Value Line adjustment procedure. His calculations produce a result that has no relationship to reality. This is because investors employ the Value Line betas directly, and so does the Commission. Hence, Mr. Knecht's CAPM calculation has no relationship with the returns that investors require.

Q. Mr. Knecht seems to suggest that tragic events in Massachusetts have had an impact on the cost of capital for CPA. Is this correct?

A. No. The use of a proxy group analysis will minimize any impact, if any, of the Massachusetts events on the cost of equity for CPA. Moreover, there has been no impact on the cost of debt for CPA. The cost of each issue of debt by CPA is based on a formula that adds a credit quality spread to the yield on Treasury bonds at the time of issue. The credit spread utilized for the CPA debt issues in 2018, 2019 and 2020 have not been impacted by the Massachusetts events. The credit spread continues to be based upon a BBB+ credit quality, as in the prior case.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 9-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF
NANCY J.D. KRAJOVIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. Nancy J. D. Krajovic, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. Are you the same Nancy J.D. Krajovic who submitted Direct Testimony in this proceeding?

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 testimony 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"). I will also make revisions to Labor Expense for the Future Test Year ("FTY") and Fully Projected Future Test Year ("FPFTY") and to the claim for other ratemaking adjustments in the FPFTY.

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, and will address the testimony of each of the witnesses listed above as they relate to those topics.

Q. Are you sponsoring any revised filing exhibits in your testimony?

A. Yes. I am sponsoring 2nd Revised Exhibit No. 104, Schedule No 10. The first revision was included as Attachment B to the Company's response to OCA 5-017. The 2nd Revision corrects a spreadsheet addition error and corrects adjustment descriptions on page 2. In addition, I will be sponsoring rebuttal Exhibits NJDK 1-R through NJDK 7-R, that are described in this rebuttal testimony.

II. DSIC

Q. What testimony regarding DSIC will you discuss?

A. Mr. Crist, beginning at page 6 of his testimony, references Columbia's initial DSIC filing at Docket P-2012-2338282 wherein the Company "claimed that if a DSIC were in place there would be a reduced need to file base rate cases. Clearly Columbia is doing just the opposite of what it stated in its DSIC filing."

Q. Is Columbia currently utilizing a DSIC?

A. Yes. The DSIC rate effective on April 1, 2020 was, 0.61% revised to 0.85% on May 7, 2020 and the DSIC rate filed on June 20, 2020 and effective July 1, 2020 is 1.69%. Exhibit NJDK-1R attached hereto includes copies of Tariff Supplement Nos. 303, 308 and 311 which were filed with those rates and those Tariff Supplements are also available on the Company's website.

Q. Why is Columbia currently utilizing a DSIC?

A. Current base rates, which were established in Columbia's last base rate proceeding filed two years ago, reflect projected rate base balances through December 31, 2019. Once the Company's investment in DSIC eligible plant exceeded those projected balances (as outlined by specific language in the settlement agreements in Columbia's last three base rate cases) the Company was able to restart its DSIC to recover the incremental investment that exceeded the projected balances as of December 31, 2019. Paragraph 29 of the Joint Petition for Partial Settlement in

Columbia's 2018 rate case, Docket No. R-2018-2647557, stated:

> As of the effective date of rates in this proceeding, Columbia will be eligible to include plant additions in the DSIC once eligible account balances exceed the levels projected by Columbia at December 31, 2019. The forgoing provision is included solely for purposes of calculating the Di SIC, and is not determinative for future ratemaking purposes of the projected additions to be included in rate base in a FPFTY filing.

Q. Was PSU signatory to that Settlement?

A. Yes, it was, and Mr. Crist was PSU's witness.

Q. How else could Columbia have sought recovery for that investment?

A. Instead of using the DSIC, the Company could have filed a base rate case in 2019 with a FPFTY ending December 31, 2020. However, Columbia elected instead to utilize a DSIC in 2020, as it has historically indicated that it would do when possible to reduce the number of base rate cases necessary to provide a return of and on the investments made in replacing the aging infrastructure in its distribution system.

Q. How long can Columbia utilize the DSIC for recovery of its 2020 DSIC-eligible investments?

A. The DSIC is currently capped at 5.o% of base rate revenues in Columbia's Tariff. Based on the level of DSIC-eligible investment being made in 2020, the calculated DSIC rate in the fourth quarter of DSIC recovery beginning January 2021 is projected to exceed 5.0% and would therefore be capped at 5.0%. I further note that the fourth quarter filing will only reflect plant additions through November 30, 2020 in accordance with the DSIC mechanism and tariff provisions. So the DSIC cannot be used to fully recover the allowed return of and on DSIC-eligible investment made in

2020 and obviously then could not be utilized to recover any investment planned for 2021. To avoid further earnings erosion, the Company therefore filed the current base rate proceeding utilizing a FPFTY ending December 31, 2021 and, as a result, the DSIC rate will be reset to zero on the date that base rates are adjusted per the resolution of this proceeding.

Q. How do you then characterize the statements made by Mr. Crist relative to Columbia's use of a DSIC?

A. Mr. Crist's statements are incorrect. Contrary to Mr. Crist's comment, Columbia is not doing "just the opposite of what it stated" but precisely what it stated, by using a DSIC for at least some recovery of 2020 eligible investments rather than having filed a base rate case in 2019 with a FPFTY ending December 31, 2020. Additionally, Table 1: Columbia Rate filings shown on page 6 of Mr. Crist's testimony is incorrect. Under the heading "Test Year Ending", the first eight entries indicate the test year that was used for proposed rates. The final entry, for the current case, lists the Future Test Year in this case ending November 30, 2020, rather than the Fully Projected Future Test Year ending December 31, 2021. The result is that it makes it appear that there is a one year period between the current case and the prior case, rather than two years between test years for base ratemaking purposes. As stated above, there was a gap between test years as Columbia did not file a base rate proceeding in 2019, which allowed the Company to use its DSIC in 2020.

As I discussed above, Columbia's use of the DSIC has been limited by the 5% cap, rather than by the Company doing the opposite of what it stated in its 2015 DSIC application. Mr. Crist ignores the fact that Columbia sought a waiver of the cap in an attempt to address the frequency of base rate filings. Specifically, on December 31, 2015 the Company filed with the Commission a Petition (Docket No. P-2016-2521993) to raise the cap on its DSIC from 5% to 10% on the basis that such an increase would allow it to possibly extend the time between future base rate proceedings. The Petition specifically identified the limited time and recovery that a 5% cap permits, given the level of DSIC eligible improvements that Columbia is making in its distribution system annually. The Petition was ultimately denied.

Q. Are there other statements in Mr. Crist's testimony regarding the DSIC that you would like to discuss?

A. Yes. On page 7, beginning at line 11 of his testimony, Mr. Crist states that "in this case the DSIC amount would be $25.2 million." This appears to be the mathematical application of 5.0% to the proposed distribution (non-gas) revenue of $504,599,218. Mr. Crist compares the $25.2 million to the initial requested revenue requirement increase in this case of $100.4 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 $504,599,218 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 revenues of $406,952,490 (Exhibit 103, Schedule 8, page 1) less approximately $4.9 million for those customers not billed the DSIC, yielding only $20.1 million, not $25.2 million.

Q. What portion of projected 2021 investment could be recovered through a DSIC had it been utilized instead of the instant proceeding?

A. None. As noted above, Columbia is currently utilizing the DSIC to begin recovery of DSIC eligible investments made to date in 2020 and intends to continue doing so throughout the pendency of the instant proceeding. Had the instant proceeding not been filed, as Mr. Crist appears to suggest, the DSIC rate would likely reach the 5.0% cap by January 1, 2021, not fully recovering of and on the 2020 eligible investments and clearly without capacity to provide the Company with any rate relief for 2021 investments. So 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.

Q. Mr. Crist's Table 1 also shows the amount claimed in each of the rate cases he identified. Do you have an observation?

A. Yes. Many of the rate cases identified were filed in consecutive years, unlike the two year gap in this case. Although the Company's 2018 rate case also was filed with a two year gap, the amount claimed was lower because the Company was transitioning from a case with higher Federal Income Taxes built into base rates to a case with lower Federal Income Taxes built into base rates.

III. O&M Adjustments and Observations

Q. Please describe other parties' adjustments to the Company's claim for O&M Expenses in the FPFTY beginning with Mr. Effron's testimony.

A. Overall, Mr. Effron characterizes the vast majority of the Company's proposed O&M increases as speculative, citing the Company's response to OCA V-13 that asked about the impact of COVID-19 on the remainder of 2020 and 2021, attached as Exhibit NJDK-2R hereto, which stated that "it is difficult to quantify the expected impact of the virus on the operation and maintenance expense." However, he did not recognize the Company's response to OCA V-12REV, attached hereto as Exhibit NJDK-3R, which states that:

> While the Company's operations have been impacted by the Pennsylvania mandated changes in business operations, as well as by the need to change practices to ensure the safety of our customers and employees, it is currently Columbia's expectation and plan that the existing work plans and capital programs for 2020 will be completed in 2020, albeit on a modified schedule.

Regarding impacts on the expenses, the response further states that:

> In mid-March accounting codes were established to track costs incurred by Columbia and the NiSource Corporate Services Company (NCSC) as a result of COVID-19 and that are incremental to usual practice. Through June 30, 2020 those charges total $738,417.13 and relate predominately to the acquisition of PPE, cleaning and sanitizing supplies, cleaning services, costs associated with working remotely as well as costs to ensure social distancing in areas where remote work is not possible.
>
> At the same time, due to the Company requiring remote work where appropriate and social distancing, there has been a savings in employee expenses associated with temporary postponement of travel, meetings, etc. A comparison of year over year expenses during the period of April through June of 2020 and the same period in 2019 show a reduction of $450,187.44 for Columbia Gas of Pennsylvania and NCSC combined.
>
> Due to the nature of other cost categories and timing of

> expenses and rescheduled work streams, an accurate identification of other potential savings will not be possible until the end of the year. It is not anticipated that significant savings from other cost categories (non-employee expenses) will be realized.

Through July 31, 2020 the Company has experienced net identified increased costs of $373,753, exclusive of uncollectibles. The Company is working to manage the impact of the changes that COVID-19 has on its operations and in its service territory, but has not furloughed, nor plans to furlough, any front line workers nor does it anticipate not being able to complete compliance work or deploy its budget to accomplish necessary and important risk-reduction work on its system.

In summary, Mr. Effron is using the cover of the pandemic, with no data to support his beliefs, to reject the use of the FPFTY ratemaking principles and return to something more closely resembling rates based on a FTY (or even Historic Test Year ("HTY") in some instances.) In fact, while individual cost element adjustments may vary from the increases proposed by the Company, Mr. Effron's total proposed adjustments of $11,264,000 (shown on Schedule C-1 to his testimony) to O&M expenses in his calculation of a Revenue Requirement represent approximately 95% of the increase to O&M expense proposed and supported by the Company in its FPFTY.

Q. Has the Company modified its Field Operations or Capital Construction Work Plans for 2021 in response to the pandemic?

A. No. Certainly the Company will continue to implement the safety processes it has instituted since March 2020 to protect both customers and employees in response to the pandemic. It will continue to evolve those processes in response to government mandate and best practice evidence as required. However, based on the results achieved to date in 2020, the Company fully anticipates that it will accomplish the Work Plan and execute the Capital Program reflected in this case for 2021.

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 eliminated the proposed increase in labor expense associated with 40 of the incremental 59 employees planned to be hired in the FTY. He based the elimination on the fact that total headcount on a monthly basis peaked at 782 in April 2020. This adjustment does not contemplate the reality of the impact of vacancies on Labor expense or overall O&M expense.

Q. Please explain further.

A. As explained in the Company's response to OCA 5-004, included as Exhibit NJDK-4R to my rebuttal testimony, the Company continues to fill a number of the incremental positions authorized in 2019 to support its growing infrastructure replacement program and low pressure enhancement program. 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 availability of Full Time Employee equivalents ("FTEs"), the work will be accomplished via overtime or the use of contracted labor recorded in Outside Services. On the Revised SDR-GAS-RR-026 included here as page 3 of Exhibit NJDK-3R, overtime payroll expense of $4,362,259 is shown during the HTY, during which the actual headcount was significantly under authorized positions as the bidding and hiring process was underway. The FTY and FPFTY budgets contemplate only $3,062,259 of overtime payroll expense, clearly including the expectation of less reliance on overtime because the labor expense assumes that all positions will be ultimately filled in those years. (Note that overtime payroll expense is also incurred as a result of emergency work and overall project efficiency efforts.) In conclusion, the adjustment of $765,000 to FPFTY Labor expense, and corresponding adjustment to FPFTY Payroll Tax Expense of approximately $55,000, proposed by Mr. Effron should be rejected.

Mr. Effron also proposes an adjustment to FPFTY Employee Benefits expense of $528,000 for 57 employees, citing that the Company did not adjust Employee Benefit expense for the elimination of 17 FPFTY employees included in the original version of SDR-GAS-RR-026. The elimination of the 17 employees FPFTY reflected the correction of an error in the FTY Labor expense. Neither the FTY or FPFTY Employee Benefits Expense were impacted by the error and both budget amounts reflected the 822 currently authorized positions. The Company adjusted the budgeted Labor expense in the FTY because that budget expense had erroneously been reduced by $763,689. As a result of that error, the increase to the FPFTY budgeted Labor expense appeared to contemplate the addition of 17 employees. Once the error was discovered and corrected, both the FTY and FPFTY Labor expense budget appropriately reflected the 822 currently authorized positions. FPFTY Labor budget shown on 2nd Revised Exhibit No. 104 Schedule 10, page 2 is approximately $40,500 lower than that shown on the original Exhibit 104, Schedule No. 10, page 2 due to rounding in the adjustments and merit calculations. For the reasons noted in the discussion above, Mr. Effron's adjustments to Employee Benefits expense as well as Labor expense to eliminate 40 positions should be rejected. And because the original claims did not include employee benefits for an additional 17 employees, the adjustment to employee benefits for the additional 17 employees should be rejected as well.

Q. What adjustment does Mr. Effron propose to Incentive Compensation expense?

A. Mr Effron proposes a downward adjustment of $775,000 to the Company's claim for Incentive Compensation expense (and a corresponding Payroll Tax adjustment) 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.

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 SDR-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. The payout in the HTY reflected that the target levels of performance were not achieved. Looking at one point in time does not provide a basis to qualify a projection as unreasonable. It is important to note that the Incentive Compensation payout level has been at or above target for all but two years since 2008. (I&E witness Mr. Zalesky also suggests an adjustment based on historical data which I address later in my testimony.) Once again, Mr. Effron's proposed adjustment 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 proposed adjustment should be rejected.

Q. What adjustments does Mr. Effron propose to the Company's claim for Outside Services Expense in the FPFTY?

A. Mr. Effron rejects the Company's proposed increase from the FTY, offset by a portion of the decrease in the HTY to the FTY. In both instances he cites a lack of support by the Company for those changes.

Q. Is there any addition detail available that supports the expenses that Mr.

Effron recommends for exclusion?

A. Yes. The Company's responses to I&E-RE-18 with Attachment A and to I&E-RE-19, which requested the basis and calculation of the budget adjustments in the Outside Services expense from the HTY to the FTY and then to the FPFTY is included herein as Exhibit NJDK-6R. The response to I&E-RE-19 (pages 5 and 6 of Exhibit NJDK-6R) identifies specific work streams that the Company anticipates will require incremental funding in the FPFTY over that in the FTY, as follows:

- underground storage well inspection and remediation activities, in response to the PHMSA regulations on Minimum Safety Standards for Underground Storage Fields effective March 13, 2020 requiring a baseline risk assessment within 4 years. Inspections are planned to be initiated in the third and fourth quarters of 2020, with completion and resultant remediation projects included in subsequent periods;
- Maximum Allowable Operating Pressure (MAOP) reconfirmation/ documentation of the Company's facilities to comply with PHMSA safety regulation amendments issued in 2019, effective July 1, 2020;
- corrosion remediation, which allows the Company to proactively identify and remediate corrosion to minimize and manage facilities that would otherwise degrade to unsatisfactory condition;
- GPS legacy and remediation programs that consistently enhances the Company's ability to locate system facilities;
- allowance for increases in contractor rates for restoration services associated with leak repair;
- allowance for increasing line locating costs driven by year over year trending ticket volume increases.

The response to I&E-RE-18 and its Attachment A (pages 1 through 4 of Exhibit NJDK-6R) provide greater detail into the changes from the HTY to the FTY budget for Outside Services Expense.

Q. What is the net effect of the recommended adjustments that Mr. Effron proposed to the Outside Services budget?

A. Mr. Effron's adjustments would reduce the Outside Services expense to $22,294,727 or $455,072 less than the Outside Service expense in the normalized HTY of TME November 30, 2019.

Q. Do you agree with that recommendation?

A. No. As noted earlier in my 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. Exhibit NJDK-1 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 increase 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 Mr. Effron proposes to the Company's claim for Safety Initiatives.

A. Mr. Effron, suggesting that the Company has not provided enough information to support the Safety Initiatives, recommends disallowance of the entire $3,896,000.

With regard to the expenses associated with additional headcount Workforce Transition (Gas Qualification Specialists) and to support the Service Line Record Enhancement initiative, Mr. Effron refers back to his position on Labor expense, which ties recovery to historic headcount, not headcount that would be engaged in the FPFTY. Once again, this argument ignores the principles of FPFTY ratemaking. The positions described in the Safety Initiatives are not reflected in the currently authorized FPFTY headcount of 822 and are therefore not currently funded. Mr. Effron has not otherwise challenged the workforce transition and legacy service line enhancement work streams described by Company witness Davidson as part of the incremental Safety Initiatives in his Mr. Davidson's direct testimony (Columbia Statement No. 7). This work is incremental to the body of work contained in the existing Work Plan. The Work Plan is designed to utilize the 822 currently authorized positions. Without incremental funding for the workforce transition ($185,000) and legacy service line enhancement program ($491,000), either there would be no employees to do that work or positions within the 822 currently authorized headcount would perform it and other work that those positions were designed to support would go undone. His recommendation that the work could be accomplished within existing authorized headcount should be rejected along with his recommendation that incremental funding be denied.

Mr. Davidson, at pages 19-20 of his rebuttal testimony (Columbia Statement No. 7-R), explains why the funding for the cross-bore program has varied from year to year and why incremental funding is necessary to accelerate the remediation of the risk that cross-bores pose in the Company's service territory. Mr. Effron's recommendation to eliminate that funding should be rejected.

Mr. Effron makes a similar argument with regard to historic levels of spending on the replacement of customer-owned field assembled risers and supposes that incremental funding doesn't mean that more will be replaced in the FPFTY than in the HTY. He ignores that the Safety Initiative is to establish an on-going base funding to programmatically support that work stream. Without incremental funding, the pace of these risk remediation programs cannot be hastened, without decreasing or eliminating other risk reducing or compliance activities, which include the replacement of Company owned field assembled risers.

The desire to accelerate the remediation is supported by I&E witness Apetoh, when he recommends at page 12 of his direct testimony that the Company "complete the inspection of all field-assembled risers in the Company's system as soon as possible... and develop a plan to replace all of the filed-assembled risers in its system, including those on customer-owned service lines."

For all of the reasons stated above, Mr. Effron's recommendation with regard to the Company's proposed increase in funding for customer-owned field assembled risers should be rejected.

Q. Mr. Effron questions the $120,000 of O&M expenses for the enhanced leak detection program. Can you provide a description of that expense?

A. Yes. Columbia proposes to equip two of its vehicles with Picarro platform systems. As described by Mr. Davidson at page 26 of his direct testimony (Columbia Statement No. 7), there are five-year licensing fees of $300,000 associated with installation on each of the two vehicles to be equipped, for a total of $600,000. Recognition of the expense over each of those five years is $120,000, annually. The proposed leak detection program cannot be implemented without the technology that enables it. Since Mr. Effron did not challenge the legitimacy of the enhanced leak detection program itself, but only suggested that incremental support for the costs was necessary, his recommendation that the costs be eliminated should be rejected.

Q. Do you agree with any of Mr. Effron's proposed disallowance of the Company's safety initiatives in the amount of $3,896,000?

A. No, and for the reasons iterated above, the recommendation should be rejected in total.

Q. What does Mr. Effron recommend with regard to the Company's Compensation Adjustments included in the FPFTY?

A. Mr. Effron recommends that the Compensation Adjustments proposed to bring certain employees' compensation up to market levels be eliminated from the FPFTY

O&M.

Q. Do you agree with the proposed elimination of this expense?

A. No. In this instance, Mr. Effron again rejects the premise of ratemaking based on a FPFTY, which inherently includes projected costs. A utility's continued ability to use the FPFTY for ratemaking is based on the reasonableness of its projections. This is the sixth base rate proceeding in which the Company has relied on a FPFTY to calculate its revenue requirement and associated revenue deficiency. His recommendation to eliminate a projected expense in a future period simply because it has not yet been incurred and with no other justification is inconsistent with the use of a FPFTY and therefore 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 an average vacancy rate of 6.44% based on budgeted positions and actual headcount for the fiscal years of 2017 – 2019 and calculates a downward adjustment of $3,011,226. I note that Mr. Zalesky proposes the adjustments to the labor expense stated on the originally filed SDR-GAS-RR-026 rather than the SDR-GAS-RR-026 REVISED included herein as page 3 of Exhibit NJDK-5R. (Please note that mathematical errors on Revised Exhibit No. 104, Schedule No. 10 have been corrected on 2nd Revised Exhibit No. 104, Schedule No. 10 included as pages 4 and 5.)

Q. Do you agree with that adjustment?

A. No. 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. For both of these reasons, it is not necessary to account for "average vacancy rate" as Mr. Zalesky suggests. I recommend that the adjustment be rejected.

Q. Did Mr. Zalesky apply the vacancy adjustment to any other expense claims?

A. Yes. Mr. Zalesky applied the same logic and calculation to adjust Other Employee Benefits Claim downward by $500,968.

Q. Do you agree with that adjustment?

A. No. Mr. Zalesky used budgeted and actual headcount data to demonstrate that there are vacancies through the year because the positions are not vacated, posted, and filled simultaneously. However, examination of budgeted versus actual Other Employee Benefits expense for the years 2017-2019 shows that there is not a corresponding underspend in that category. In fact, the level of actual Other

Employee Benefits expense has exceeded budgets in two of those years. Please refer to Exhibit NJDK-1 to my direct testimony, Other Employee Benefits – Variance. Actual Other Employee Benefits expense can vary from budgets for reasons unrelated to headcount such as, for example, actual costs associated with the benefits themselves (insurance premiums) and actual payouts during a given period. Mr. Zalesky's proposed adjustment should therefore be rejected.

Q. What adjustment does Mr. Zalesky propose with regard to Incentive Compensation?

A. Mr. Zalesky proposes a downward adjustment in the amount of $373,749 to the Incentive Compensation expense claim (and a corresponding Payroll Tax adjustment) associated with Columbia employees. Mr. Zalesky bases the adjustment on a three-year historic average of Incentive Compensation expense. Use of historical averages ignores the fact that the claim in this case is based on a FPFTY and that actual Incentive Compensation awarded depends on many factors, as described in Company Witness Cartella's Rebuttal Testimony. Additionally, incentive compensation is paid as a percentage of base pay, and the historic three year average used is several years out of sync with payroll growth. Mr. Zalesky calculates his recommended allowance for Incentive Compensation using the per books Incentive Compensation expenses for the TME 11/30/17 and 11/30/18 and the normalized expense for the HTY of TME 11/30/19. Normalized expenses include ratemaking adjustments. Although the normalized expense is only greater than the per books expense by $4,354 for the HTY of TME 11/30/19, I recommend consistent components be used, producing an average of $1,891,800 rather than the average calculated by Mr. Zalesky of $1,893,251.

Historical Incentive Compensation expense data by year or averaged become useful as a tool when examined as a percentage of labor expense during those, or averaged over those, corresponding historical periods. As I have noted above, incentive compensation is paid on percentage of base pay, and there has been notable growth in labor expense over the period of 2017 through current day with the growth of the Company's employee base pay. Average annual labor expense for the TME 11/30/17, TME 11/30/18 and TME 11/30/19 is $32,823,777 as shown in the table below:

Period	Per Books Labor Expense
TME 11/30/17	$30,125,334
TME 11/30/18	$32,215,808
TME 11/30/19	$36,130,190
Total	$98,471,332
Average	$32,823,777

Using an adjusted three year average of per book Incentive Compensation as noted above of $1,891,800 compared to the average labor expense of $32,823,777 produces a payout ratio of 5.8%. Applying that average payout ratio to the budgeted labor expense for FPFTY of TME 12/31/21 of $38,998,504 (shown on Exhibit NJDK-5R, page 5) yields an outcome of $2,261,913, which is comparable to the Company's claim of $2,267,000 for Incentive Compensation expense projected in the FPFTY budget.

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 the historical average of actual Incentive Compensation paid does not recognize the inherent relationship to actual labor expense. If historical data is to be used it should be based upon a payout ratio of actual Incentive Compensation paid to actual Labor Expense as I have described above.

Q. Mr. Zalesky proposes to reduce the Company's claim for PUC/OCA/OSBA fees to reflect the assessment for the current fiscal year of July 2019 to June 2020. Do you agree with that recommendation?

A. No. In his testimony, Mr. Zalesky states as a basis for his recommendation, that "due to the current pandemic the present moment is a special time without historical precedence and using the most recent assessment is reasonable because it is lower than other recent years. Finally, my recommendation may be higher than actual future costs given the unique circumstances of this pandemic."

When asked in discovery, Mr. Zalesky was unable to provide any information or insight into the proposed PUC/OCA/OSBA budgets for fiscal year 2020-2021. The discovery response, included as Exhibit NJDK-7R, states that:

> Mr. Zalesky did not state nor imply that the current assessment factors will be adjusted or affected by the pandemic as the current assessment factors will be based on natural gas gross revenues reported via annual

> assessment reports for the year ended December 31, 2019 and the 2021-2021 PUC/OSBA/OCA/DPC annual budgets as finalized earlier this year. However, future budgets **could be** affected by modifications to operations that **may** reduce budgets due to long-term impacts to operations such as potential extended travel restrictions, and it would be inappropriate to embed an amount for assessments in base rates that may never be realized before the Company's next base rate case. (Emphasis added.)

The basis for Mr. Zalesky's adjustment is unsubstantiated conjecture. It is just as likely that the pandemic could result in a net increase of costs due to requirements for social distancing in the workplace, sanitation and cleaning service costs incurred when COVID-19 exposure has occurred, incremental technology costs to allow for remote working, etc. For these reasons, Mr. Zalesky's proposed adjustment should be rejected.

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 2014 case. It is not clear why O&M expense in 2014 is of relevance, but Mr. Crist historically uses that as a point of comparison.

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 Kitchell has explained in his direct testimony (Columbia Statement No. 14), 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. You indicated that you are revising certain FTY and FPFTY expenses. Please describe them, beginning with the revision to Labor expense in the FTY and the FPFTY.

A. As described in the Company's response to OCA 5-017, included herein as Exhibit NJDK-5R, the FTY claim for Labor expense has been increased by $817,385 to correct an error made in the development of SDR-GAS-RR-026 (and SDR-GAS-RR-026 has since been revised as well). There was a minor increase of $8,415 to the claim for Labor expense in the FPFTY as a result of that correction in the FTY. The adjustments to FTY and FPFTY Labor expense have an associated impact on payroll taxes. Company witness Miller provides a breakout of the impacts to Labor Expense in the FTY and FPFTY resulting from the response to OCA-5-017 and revised GAS-RR-026 in Exhibit KKM-3R, provided with her rebuttal testimony (Columbia Statement 4-R).

There are also additional changes to merit increases included in the calculation of Labor expense, addressed by Company witness Cartella in her Rebuttal testimony (Columbia Statement No. 16-R) and reflected in Company witness Miller's Rebuttal testimony and Exhibit KKM-3R.

Q. What is the next revision?

A. During the discovery process, it was recognized that the claim for $280,000 in O&M expense for Budget Billing Modification Costs discussed in Company witness Davis's direct testimony (Columbia Statement No. 13) and included in the Other FPFTY Adjustments detailed on Exhibit No. 104, Schedule No. 2 page 18 of 19, actually represents a capital investment and not an ongoing O&M expense. Correction of this error reduces the Other FPFTY Adjustment claim by $280,000 as reflected in Company witness Miller's Exhibit KKM-1R.

Q. How are your revisions incorporated into the Exhibits supporting the Company's O&M claim?

A. Company witness Miller's rebuttal testimony and accompanying Exhibits reflect my revisions.

Q. Are there any other anticipated changes that may impact the projected O&M costs in the FPFTY?

A. As a result of NiSource's sale of Columbia Gas of Massachusetts to Eversource, which is anticipated to be fully executed during the third quarter of 2020, there will be a loss of scale of operations resulting in a higher percentage allocation of costs for the services received from the NiSource Corporate Services Corporation and reflected as

NCSC Expense component of O&M than what is projected on the schedules filed in this proceeding. So, while the percentage of NCSC costs that are allocated to CPA will increase during the FPFTY, the Company is not seeking to revise its claim for NCSC expense. NiSource has initiated organizational changes to more appropriately match the needs of the remaining business while reflecting its commitment to the safe and reliable provision of utility services to its customers. While the changes have not matured to discrete identifiable changes in organizational structure or specific processes and therefore expenses at Columbia Gas of Pennsylvania at a cost element level, the Company anticipates some mitigation of the increase that would ultimately manifest in overall 2021 O&M costs. As I noted above, the Company is therefore not revising its NCSC expense claim.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Supplement No. 303 to
Tariff Gas – Pa. P.U.C. No. 9

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 **Canonsburg, Pennsylvania**

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: March 20, 2020 EFFECTIVE: April 1, 2020

ISSUED BY: M. A. HUWAR, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Changes to the Existing Tariff - See List of Changes Made by This Tariff Supplement on Page No. 2.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement No., Issue and Effective Date.
2	List of Changes	List of Changes.
16	Rate Summary	The “Distribution System Improvement Charge (DSIC)” has increased. The “Total Effective Rate” has increased.
17	Rate Summary	The “Distribution System Improvement Charge (DSIC)” has increased. The “Total Effective Rate” has increased.
18	Rate Summary	The “Distribution System Improvement Charge (DSIC)” has increased. The “Total Effective Rate” has increased.
19	Rate Summary	The “Distribution System Improvement Charge (DSIC)” has increased. The “Total Effective Rate” has increased.
21	Rider Summary	The “Distribution System Improvement Charge – Rider DSIC” has increased.
177	Distribution System Improvement Charge	Changed the percentage from 0.24% to 0.61%.

Supplement No. 303 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Forty-third Revised Page No. 16
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Forty-second Revised Page No. 16**

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate
Rate RSS - Residential Sales Service									
Customer Charge	$	16.75				0.00	0.10	(0.61)	16.24
Usage Charge	$	0.60763	0.23778	(0.00680)	0.19558	0.00000	0.00371	(0.02196)	1.01594
Rate RDS - Residential Distribution Service									
Customer Charge	$	16.75				0.00	0.10	(0.61)	16.24
Usage Charge:									
Customers Electing CHOICE	$	0.60763	-	-	0.17597	0.00000	0.00371	(0.02196)	0.76535

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
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Issued: March 20, 2020 **Effective: April 1, 2020**

M. A. Huwar - President

Supplement No. 303 to
Tariff Gas - Pa. P.U.C. No. 9
Eighty-sixth Revised Page No. 17
Columbia Gas of Pennsylvania, Inc. **Canceling Eighty-fifth Revised Page No. 17**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate SGSS - Small General Sales Service										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.14	(0.82)	22.07	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.29	(1.73)	46.56	
Usage Charge										
Annual Throughput <= 6,440 thm	$	0.44145	0.23526	(0.00680)	0.12769	0.00000	0.00269	(0.01595)	0.78434	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.37912	0.23526	(0.00680)	0.12769	0.00000	0.00231	(0.01370)	0.72388	
Rate SCD - Small Commercial Distribution										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.14	(0.82)	22.07	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.29	(1.73)	46.56	
Usage Charge: Customers Electing CHOICE										
Annual Throughput <=6,440 thm	$	0.44145	-	-	0.10808	0.00000	0.00269	(0.01595)	0.53627	
Annual Throughput >6,440 and <=64,400 thm	$	0.37912	-	-	0.10808	0.00000	0.00231	(0.01370)	0.47581	
Rate SGDS - Small General Distribution Service										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.14	(0.82)	22.07	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.29	(1.73)	46.56	
Usage Charge - Priority One										
Annual Throughput <= 6,440 thm	$	0.42925	-	-	0.12769	0.00000	0.00262	(0.01551)	0.54405	6/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.36691	-	-	0.12769	0.00000	0.00224	(0.01326)	0.48358	6/
Usage Charge - Non-Priority One										
Annual Throughput <= 6,440 thm	$	0.42925	-	-	0.00010	0.00000	0.00262	(0.01551)	0.41646	6/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.36691	-	-	0.00010	0.00000	0.00224	(0.01326)	0.35599	6/

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6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Issued: March 20, 2020 **Effective: April 1, 2020**

M. A. Huwar - President

Supplement No. 303 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Twentieth Revised Page No. 18
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred-nineteenth Revised Page No. 18**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate LGSS - Large General Sales Service										
Customer Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	1.40	(8.30)	222.85	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	4.62	(27.37)	734.59	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	11.88	(70.37)	1,888.57	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	18.48	(109.46)	2,937.78	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	35.63	(211.10)	5,665.71	
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	52.79	(312.74)	8,393.65	
Usage Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.26138	0.23459	(0.00680)	0.12759	0.00000	0.00159	(0.00945)	0.60890	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.24437	0.23459	(0.00680)	0.12759	0.00000	0.00149	(0.00883)	0.59241	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.14131	0.23459	(0.00680)	0.12759	0.00000	0.00086	(0.00511)	0.49244	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.12535	0.23459	(0.00680)	0.12759	0.00000	0.00076	(0.00453)	0.47696	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.11249	0.23459	(0.00680)	0.12759	0.00000	0.00069	(0.00407)	0.46449	
Annual Throughput > 7,500,000 thm	$	0.06693	0.23459	(0.00680)	0.12759	0.00000	0.00041	(0.00242)	0.42030	
Rate SDS - Small Distribution Service										
Customer Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	1.40	(8.30)	222.85	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	4.62	(27.37)	734.59	
Usage Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.26138	-	-	-	0.00000	0.00159	(0.00945)	0.25352	6/
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.24437	-	-	-	0.00000	0.00149	(0.00883)	0.23703	6/
Rate LDS - Large Distribution Service										
Customer Charge:										
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	11.88	(70.37)	1,888.57	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	18.48	(109.46)	2,937.78	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	35.63	(211.10)	5,665.71	
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	52.79	(312.74)	8,393.65	
Usage Charge:										
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.14131	-	-	-	0.00000	0.00086	(0.00511)	0.13706	6/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.12535	-	-	-	0.00000	0.00076	(0.00453)	0.12158	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.11249	-	-	-	0.00000	0.00069	(0.00407)	0.10911	6/
Annual Throughput > 7,500,000 thm	$	0.06693	-	-	-	0.00000	0.00041	(0.00242)	0.06492	6/

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Issued: March 20, 2020 **Effective: April 1, 2020**

M. A. Huwar - President

Supplement No. 303 to
Tariff Gas - Pa. P.U.C. No. 9
Forty-ninth Revised Page No. 19
Columbia Gas of Pennsylvania, Inc. **Canceling Forty-eighth Revised Page No. 19**

Rate Summary

Rate per thm

Main Line Service Rate Schedules Commercial / Industrial		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate MLSS - Main Line Sales Service										
Customer Charge:										
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	2.86	(16.96)	455.24	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	7.01	(41.52)	1,114.49	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	12.51	(74.09)	1,988.42	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	24.99	(148.03)	3,972.96	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	44.66	(264.62)	7,102.04	
Usage Charge:										
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	0.23459	(0.00680)	0.12759	0.00000	0.00006	(0.00034)	0.36447	
MLS Class II:										
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04479	0.23459	(0.00680)	0.12759	0.00000	0.00027	(0.00162)	0.39882	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03874	0.23459	(0.00680)	0.12759	0.00000	0.00024	(0.00140)	0.39296	
Annual Throughput > 7,500,000 thm	$	0.03355	0.23459	(0.00680)	0.12759	0.00000	0.00020	(0.00121)	0.38792	
Rate MLDS - Main Line Distribution Service										
Customer Charge:										
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	2.86	(16.96)	455.24	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	7.01	(41.52)	1,114.49	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	12.51	(74.09)	1,988.42	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	24.99	(148.03)	3,972.96	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	44.66	(264.62)	7,102.04	
Usage Charge:										
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	-	-	-	0.00000	0.00006	(0.00034)	0.00909	6/
MLS Class II:										
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04479	-	-	-	0.00000	0.00027	(0.00162)	0.04344	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03874	-	-	-	0.00000	0.00024	(0.00140)	0.03758	6/
Annual Throughput > 7,500,000 thm	$	0.03355	-	-	-	0.00000	0.00020	(0.00121)	0.03254	6/

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Issued: March 20, 2020 **Effective: April 1, 2020**

M. A. Huwar - President

Supplement No. 303 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Fifty-fifth Revised Page No. 21
Columbia Gas of Pennsylvania, Inc.
Canceling One Hundred Fifty-fourth Revised Page No. 21

Rider Summary

Riders		Rate		Applicable Rate Schedules
Customer Choice - Rider CC	$	0.00010	/thm	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$	0.06824	/thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC		0.61%		This percentage is applied to the Distribution Charge and the Customer Charge. See Pages 177-180 for Rider DSIC details.
Elective Balancing Service - Rider EBS:				
Option 1 - Small Customer	$	0.01444	/thm	SGDS/SDS
Option 1 - Large Customer	$	0.00755	/thm	LDS/MLDS
Option 2 - Small Customer	$	0.00697	/thm	SGDS/SDS
Option 2 - Large Customer	$	0.00226	/thm	LDS/MLDS
Gas Procurement Charge - Rider GPC	$	0.00695	/thm	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$	0.00319	/thm	RSS
Merchant Function Charge - Rider MFC	$	0.00067	/thm	SGSS
Purchased Gas Cost - Rider PGC		Pg. 21a & 21b		Rate Schedules specified on Page 21a & 21b

Issued: March 20, 2020 **Effective: April 1, 2020**

M. A. Huwar - President

RIDER DSIC - DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

In addition to the net charges provided for in this Tariff, a charge of 0.61% will apply consistent with the Commission Order dated March 14, 2013 at Docket No. P-2012-2338282,approving the DSIC. (I)

GENERAL DESCRIPTION

Purpose

To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Utility with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

Eligible Property

The DSIC-eligible property will consist of the following:

- Piping (account 376);
- Couplings (account 376);
- Gas services lines (account 380) and insulated and non-insulated fittings (account 378);
- Valves (account 376);
- Excess flow valves (account 376);
- Risers (account 376);
- Meter bars (account 382);
- Meters (account 381);
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities; and
- Other related capitalized costs.

Effective Date

The DSIC will become effective for bills rendered on and after April 1, 2020.

(I) Indicates Increase

Supplement No. 308 to
Tariff Gas – Pa. P.U.C. No. 9

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 **Canonsburg, Pennsylvania**

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: April 27, 2020 EFFECTIVE: May 7, 2020

ISSUED BY: M. A. HUWAR, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Changes to the Existing Tariff - See List of Changes Made by This Tariff Supplement on Page No. 2.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

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19	Rate Summary	The “Distribution System Improvement Charge (DSIC)” has increased. The “Total Effective Rate” has increased.
21	Rider Summary	The “Distribution System Improvement Charge – Rider DSIC” has increased.
177	Distribution System Improvement Charge	Changed the percentage from 0.61% to 0.85%.

Supplement No. 308 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Forty-eigth Revised Page No. 16
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Forty-fifth Revised Page No. 16**

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate
Rate RSS - Residential Sales Service									
Customer Charge	$	16.75				0.00	0.14	(0.61)	16.28
Usage Charge	$	0.60763	0.20091	(0.00680)	0.20998	0.00000	0.00516	(0.02196)	0.99492
Rate RDS - Residential Distribution Service									
Customer Charge	$	16.75				0.00	0.14	(0.61)	16.28
Usage Charge:									
Customers Electing CHOICE	$	0.60763	-	-	0.19003	0.00000	0.00516	(0.02196)	0.78086

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Issued: April 27, 2020 **Effective: May 7, 2020**

M. A. Huwar - President

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate SGSS - Small General Sales Service										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.19	(0.82)	22.12	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.41	(1.73)	46.68	
Usage Charge										
Annual Throughput <= 6,440 thm	$	0.44145	0.19880	(0.00680)	0.14159	0.00000	0.00375	(0.01595)	0.76284	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.37912	0.19880	(0.00680)	0.14159	0.00000	0.00322	(0.01370)	0.70223	
Rate SCD - Small Commercial Distribution										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.19	(0.82)	22.12	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.41	(1.73)	46.68	
Usage Charge: Customers Electing CHOICE										
Annual Throughput <=6,440 thm	$	0.44145	-	-	0.12164	0.00000	0.00375	(0.01595)	0.55089	
Annual Throughput >6,440 and <=64,400 thm	$	0.37912	-	-	0.12164	0.00000	0.00322	(0.01370)	0.49028	
Rate SGDS - Small General Distribution Service										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.19	(0.82)	22.12	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.41	(1.73)	46.68	
Usage Charge - Priority One										
Annual Throughput <= 6,440 thm	$	0.42925	-	-	0.14159	0.00000	0.00365	(0.01551)	0.55898	6/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.36691	-	-	0.14159	0.00000	0.00312	(0.01326)	0.49836	6/
Usage Charge - Non-Priority One										
Annual Throughput <= 6,440 thm	$	0.42925	-	-	0.00010	0.00000	0.00365	(0.01551)	0.41749	6/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.36691	-	-	0.00010	0.00000	0.00312	(0.01326)	0.35687	6/

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Supplement No. 308 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Twenty-fourth Revised Page No. 18
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Twenty-first Revised Page No. 18**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate LGSS - Large General Sales Service										
Customer Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	1.95	(8.30)	223.40	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	6.44	(27.37)	736.41	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	16.55	(70.37)	1,893.24	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	25.74	(109.46)	2,945.04	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	49.65	(211.10)	5,679.73	
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	73.56	(312.74)	8,414.42	
Usage Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.26138	0.19823	(0.00680)	0.14149	0.00000	0.00222	(0.00945)	0.58707	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.24437	0.19823	(0.00680)	0.14149	0.00000	0.00208	(0.00883)	0.57054	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.14131	0.19823	(0.00680)	0.14149	0.00000	0.00120	(0.00511)	0.47032	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.12535	0.19823	(0.00680)	0.14149	0.00000	0.00107	(0.00453)	0.45481	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.11249	0.19823	(0.00680)	0.14149	0.00000	0.00096	(0.00407)	0.44230	
Annual Throughput > 7,500,000 thm	$	0.06693	0.19823	(0.00680)	0.14149	0.00000	0.00057	(0.00242)	0.39800	
Rate SDS - Small Distribution Service										
Customer Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	1.95	(8.30)	223.40	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	6.44	(27.37)	736.41	
Usage Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.26138	-	-	-	0.00000	0.00222	(0.00945)	0.25415	6/
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.24437	-	-	-	0.00000	0.00208	(0.00883)	0.23762	6/
Rate LDS - Large Distribution Service										
Customer Charge:										
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	16.55	(70.37)	1,893.24	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	25.74	(109.46)	2,945.04	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	49.65	(211.10)	5,679.73	
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	73.56	(312.74)	8,414.42	
Usage Charge:										
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.14131	-	-	-	0.00000	0.00120	(0.00511)	0.13740	6/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.12535	-	-	-	0.00000	0.00107	(0.00453)	0.12189	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.11249	-	-	-	0.00000	0.00096	(0.00407)	0.10938	6/
Annual Throughput > 7,500,000 thm	$	0.06693	-	-	-	0.00000	0.00057	(0.00242)	0.06508	6/

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
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6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Issued: April 27, 2020 **Effective: May 7, 2020**

M. A. Huwar - President

Supplement No. 308 to
Tariff Gas - Pa. P.U.C. No. 9
Fifty-third Revised Page No. 19
Columbia Gas of Pennsylvania, Inc. **Canceling Fiftieth Revised Page No. 19**

Rate Summary

Rate per thm

Main Line Service Rate Schedules Commercial / Industrial		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate MLSS - Main Line Sales Service										
Customer Charge:										
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	3.99	(16.96)	456.37	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	9.77	(41.52)	1,117.25	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	17.43	(74.09)	1,993.34	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	34.82	(148.03)	3,982.79	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	62.24	(264.62)	7,119.62	
Usage Charge:										
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	0.19823	(0.00680)	0.14149	0.00000	0.00008	(0.00034)	0.34203	
MLS Class II:										
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04479	0.19823	(0.00680)	0.14149	0.00000	0.00038	(0.00162)	0.37647	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03874	0.19823	(0.00680)	0.14149	0.00000	0.00033	(0.00140)	0.37059	
Annual Throughput > 7,500,000 thm	$	0.03355	0.19823	(0.00680)	0.14149	0.00000	0.00029	(0.00121)	0.36555	
Rate MLDS - Main Line Distribution Service										
Customer Charge:										
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	3.99	(16.96)	456.37	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	9.77	(41.52)	1,117.25	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	17.43	(74.09)	1,993.34	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	34.82	(148.03)	3,982.79	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	62.24	(264.62)	7,119.62	
Usage Charge:										
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	-	-	-	0.00000	0.00008	(0.00034)	0.00911	6/
MLS Class II:										
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04479	-	-	-	0.00000	0.00038	(0.00162)	0.04355	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03874	-	-	-	0.00000	0.00033	(0.00140)	0.03767	6/
Annual Throughput > 7,500,000 thm	$	0.03355	-	-	-	0.00000	0.00029	(0.00121)	0.03263	6/

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6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Issued: April 27, 2020 **Effective: May 7, 2020**

M. A. Huwar - President

Supplement No. 308 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Sixtieth Revised Page No. 21
Columbia Gas of Pennsylvania, Inc. **Canceling One Hundred Fifty-seventh Revised Page No. 21**

Rider Summary

Riders	Rate			Applicable Rate Schedules
Customer Choice - Rider CC	$	0.00010	/thm	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$	0.06874	/thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC		0.85%		This percentage is applied to the Distribution Charge and the Customer Charge. See Pages 177-180 for Rider DSIC details.
Elective Balancing Service - Rider EBS:				
Option 1 - Small Customer	$	0.01444	/thm	SGDS/SDS
Option 1 - Large Customer	$	0.00755	/thm	LDS/MLDS
Option 2 - Small Customer	$	0.00697	/thm	SGDS/SDS
Option 2 - Large Customer	$	0.00226	/thm	LDS/MLDS
Gas Procurement Charge - Rider GPC	$	0.00695	/thm	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$	0.00268	/thm	RSS
Merchant Function Charge - Rider MFC	$	0.00057	/thm	SGSS
Purchased Gas Cost - Rider PGC		Pg. 21a & 21b		Rate Schedules specified on Page 21a & 21b

Issued: April 27, 2020 **Effective: May 7, 2020**

M. A. Huwar - President

RIDER DSIC - DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

In addition to the net charges provided for in this Tariff, a charge of 0.85% will apply consistent with the Commission Order dated March 14, 2013 at Docket No. P-2012-2338282,approving the DSIC. (I)

GENERAL DESCRIPTION

Purpose

To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Utility with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

Eligible Property

The DSIC-eligible property will consist of the following:

- Piping (account 376);
- Couplings (account 376);
- Gas services lines (account 380) and insulated and non-insulated fittings (account 378);
- Valves (account 376);
- Excess flow valves (account 376);
- Risers (account 376);
- Meter bars (account 382);
- Meters (account 381);
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities; and
- Other related capitalized costs.

Effective Date

The DSIC will become effective for bills rendered on and after May 7, 2020.

(I) Indicates Increase

Supplement No. 311 to
Tariff Gas – Pa. P.U.C. No. 9

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 **Canonsburg, Pennsylvania**

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: June 19, 2020 EFFECTIVE: July 1, 2020

ISSUED BY: M. A. HUWAR, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Changes to the Existing Tariff - See List of Changes Made by This Tariff Supplement on Page No. 2.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement No., Issue and Effective Date.
2	List of Changes	List of Changes.
16	Rate Summary	The "Distribution System Improvement Charge (DSIC)" has increased. The "Total Effective Rate" has increased.
17	Rate Summary	The "Distribution System Improvement Charge (DSIC)" has increased. The "Total Effective Rate" has increased.
18	Rate Summary	The "Distribution System Improvement Charge (DSIC)" has increased. The "Total Effective Rate" has increased.
19	Rate Summary	The "Distribution System Improvement Charge (DSIC)" has increased. The "Total Effective Rate" has increased.
21	Rider Summary	The "Distribution System Improvement Charge – Rider DSIC" has increased.
177	Distribution System Improvement Charge	Changed the percentage from 0.85% to 1.69%.

Supplement No. 311 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Forty-ninth Revised Page No. 16
Canceling One Hundred Forty-eigth Revised Page No. 16

Columbia Gas of Pennsylvania, Inc.

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate
Rate RSS - Residential Sales Service									
Customer Charge	$	16.75				0.00	0.28	(0.61)	16.42
Usage Charge	$	0.60763	0.20091	(0.00680)	0.20998	0.00000	0.01027	(0.02196)	1.00003
Rate RDS - Residential Distribution Service									
Customer Charge	$	16.75				0.00	0.28	(0.61)	16.42
Usage Charge:									
Customers Electing CHOICE	$	0.60763	-	-	0.19003	0.00000	0.01027	(0.02196)	0.78597

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Issued: June 19, 2020 **Effective: July 1, 2020**

M. A. Huwar - President

Supplement No. 311 to
Tariff Gas - Pa. P.U.C. No. 9
Ninety-first Revised Page No. 17
Columbia Gas of Pennsylvania, Inc. **Canceling Ninetieth Revised Page No. 17**

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
<u>Rate SGSS - Small General Sales Service</u>										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.38	(0.82)	22.31	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.81	(1.73)	47.08	
Usage Charge										
Annual Throughput <= 6,440 thm	$	0.44145	0.19880	(0.00680)	0.14159	0.00000	0.00746	(0.01595)	0.76655	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.37912	0.19880	(0.00680)	0.14159	0.00000	0.00641	(0.01370)	0.70542	
<u>Rate SCD - Small Commercial Distribution</u>										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.38	(0.82)	22.31	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.81	(1.73)	47.08	
Usage Charge: Customers Electing CHOICE										
Annual Throughput <=6,440 thm	$	0.44145	-	-	0.12164	0.00000	0.00746	(0.01595)	0.55460	
Annual Throughput >6,440 and <=64,400 thm	$	0.37912	-	-	0.12164	0.00000	0.00641	(0.01370)	0.49347	
<u>Rate SGDS - Small General Distribution Service</u>										
Customer Charge:										
Annual Throughput <= 6,440 thm	$	22.75				0.00	0.38	(0.82)	22.31	
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00				0.00	0.81	(1.73)	47.08	
Usage Charge - Priority One										
Annual Throughput <= 6,440 thm	$	0.42925	-	-	0.14159	0.00000	0.00725	(0.01551)	0.56258	6/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.36691	-	-	0.14159	0.00000	0.00620	(0.01326)	0.50144	6/
Usage Charge - Non-Priority One										
Annual Throughput <= 6,440 thm	$	0.42925	-	-	0.00010	0.00000	0.00725	(0.01551)	0.42109	6/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.36691	-	-	0.00010	0.00000	0.00620	(0.01326)	0.35995	6/

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6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Issued: June 19, 2020 **Effective: July 1, 2020**

M. A. Huwar - President

Supplement No. 311 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Twenty-fifth Revised Page No. 18
Columbia Gas of Pennsylvania, Inc.
Canceling One Hundred Twenty-fourth Revised Page No. 18

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate LGSS - Large General Sales Service										
Customer Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	3.88	(8.30)	225.33	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	12.80	(27.37)	742.77	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	32.91	(70.37)	1,909.60	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	51.19	(109.46)	2,970.49	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	98.72	(211.10)	5,728.80	
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	146.25	(312.74)	8,487.11	
Usage Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.26138	0.19823	(0.00680)	0.14149	0.00000	0.00442	(0.00945)	0.58927	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.24437	0.19823	(0.00680)	0.14149	0.00000	0.00413	(0.00883)	0.57259	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.14131	0.19823	(0.00680)	0.14149	0.00000	0.00239	(0.00511)	0.47151	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.12535	0.19823	(0.00680)	0.14149	0.00000	0.00212	(0.00453)	0.45586	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.11249	0.19823	(0.00680)	0.14149	0.00000	0.00190	(0.00407)	0.44324	
Annual Throughput > 7,500,000 thm	$	0.06693	0.19823	(0.00680)	0.14149	0.00000	0.00113	(0.00242)	0.39856	
Rate SDS - Small Distribution Service										
Customer Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	3.88	(8.30)	225.33	
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	12.80	(27.37)	742.77	
Usage Charge:										
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.26138	-	-	-	0.00000	0.00442	(0.00945)	0.25635	6/
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.24437	-	-	-	0.00000	0.00413	(0.00883)	0.23967	6/
Rate LDS - Large Distribution Service										
Customer Charge:										
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	32.91	(70.37)	1,909.60	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	51.19	(109.46)	2,970.49	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	98.72	(211.10)	5,728.80	
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	146.25	(312.74)	8,487.11	
Usage Charge:										
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.14131	-	-	-	0.00000	0.00239	(0.00511)	0.13859	6/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.12535	-	-	-	0.00000	0.00212	(0.00453)	0.12294	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.11249	-	-	-	0.00000	0.00190	(0.00407)	0.11032	6/
Annual Throughput > 7,500,000 thm	$	0.06693	-	-	-	0.00000	0.00113	(0.00242)	0.06564	6/

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Issued: June 19, 2020
Effective: July 1, 2020

M. A. Huwar - President

Supplement No. 311 to
Tariff Gas - Pa. P.U.C. No. 9
Fifty-fourth Revised Page No. 19
Columbia Gas of Pennsylvania, Inc. **Canceling Fifty-third Revised Page No. 19**

Rate Summary

Rate per thm

Main Line Service Rate Schedules Commercial / Industrial		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Distribution System Improvement Charge (DSIC) 4/	Federal Tax Adjustment Credit (FTAC) 5/	Total Effective Rate	
Rate MLSS - Main Line Sales Service										
Customer Charge:										
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	7.93	(16.96)	460.31	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	19.42	(41.52)	1,126.90	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	34.65	(74.09)	2,010.56	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	69.22	(148.03)	4,017.19	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	123.74	(264.62)	7,181.12	
Usage Charge:										
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	0.19823	(0.00680)	0.14149	0.00000	0.00016	(0.00034)	0.34211	
MLS Class II:										
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04479	0.19823	(0.00680)	0.14149	0.00000	0.00076	(0.00162)	0.37685	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03874	0.19823	(0.00680)	0.14149	0.00000	0.00065	(0.00140)	0.37091	
Annual Throughput > 7,500,000 thm	$	0.03355	0.19823	(0.00680)	0.14149	0.00000	0.00057	(0.00121)	0.36583	
Rate MLDS - Main Line Distribution Service										
Customer Charge:										
Annual Throughput > 274,000 thm and <= 540,000 thm	$	469.34				0.00	7.93	(16.96)	460.31	
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,149.00				0.00	19.42	(41.52)	1,126.90	
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	2,050.00				0.00	34.65	(74.09)	2,010.56	
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	4,096.00				0.00	69.22	(148.03)	4,017.19	
Annual Throughput > 7,500,000 thm	$	7,322.00				0.00	123.74	(264.62)	7,181.12	
Usage Charge:										
MLS Class I Annual Throughput > 274,000 thm	$	0.00937	-	-	-	0.00000	0.00016	(0.00034)	0.00919	6/
MLS Class II:										
Annual Throughput > 2,146,000 thm and <= 3,400,000 thm	$	0.04479	-	-	-	0.00000	0.00076	(0.00162)	0.04393	6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.03874	-	-	-	0.00000	0.00065	(0.00140)	0.03799	6/
Annual Throughput > 7,500,000 thm	$	0.03355	-	-	-	0.00000	0.00057	(0.00121)	0.03291	6/

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ The DSIC percentage is reflected on Page No. 21 and is applied to the Customer Charge and the Distribution Charge.
5/ The FTAC percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Issued: June 19, 2020 **Effective: July 1, 2020**

M. A. Huwar - President

Supplement No. 311 to
Tariff Gas - Pa. P.U.C. No. 9
One Hundred Sixty-first Revised Page No. 21
Canceling One Hundred Sixtieth Revised Page No. 21

Columbia Gas of Pennsylvania, Inc.

Rider Summary

Riders	Rate			Applicable Rate Schedules
Customer Choice - Rider CC	$	0.00010	/thm	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$	0.06874	/thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC		1.69%		This percentage is applied to the Distribution Charge and the Customer Charge. See Pages 177-180 for Rider DSIC details.
Elective Balancing Service - Rider EBS:				
Option 1 - Small Customer	$	0.01444	/thm	SGDS/SDS
Option 1 - Large Customer	$	0.00755	/thm	LDS/MLDS
Option 2 - Small Customer	$	0.00697	/thm	SGDS/SDS
Option 2 - Large Customer	$	0.00226	/thm	LDS/MLDS
Gas Procurement Charge - Rider GPC	$	0.00695	/thm	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$	0.00268	/thm	RSS
Merchant Function Charge - Rider MFC	$	0.00057	/thm	SGSS
Purchased Gas Cost - Rider PGC		Pg. 21a & 21b		Rate Schedules specified on Page 21a & 21b

Issued: June 19, 2020 **Effective: July 1, 2020**

M. A. Huwar - President

RIDER DSIC - DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

In addition to the net charges provided for in this Tariff, a charge of 1.69% will apply consistent with the Commission Order dated March 14, 2013 at Docket No. P-2012-2338282,approving the DSIC. (I)

GENERAL DESCRIPTION

Purpose

To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Utility with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

Eligible Property

The DSIC-eligible property will consist of the following:

- Piping (account 376);
- Couplings (account 376);
- Gas services lines (account 380) and insulated and non-insulated fittings (account 378);
- Valves (account 376);
- Excess flow valves (account 376);
- Risers (account 376);
- Meter bars (account 382);
- Meters (account 381);
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities; and
- Other related capitalized costs.

Effective Date

The DSIC will become effective for bills rendered on and after July 1, 2020.

(I) Indicates Increase

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 5

Question No. OCA 5-013:

Please describe the expected impact of COVID-19 on operation and maintenance expense for the remaining months of 2020 and for 2021. The response should include any documentation or analysis addressing the effect of COVID-19 on expenses.

Response:

As the COVID-19 pandemic continues with an ever-changing response, it is difficult to quantify the expected impact of the virus on operation and maintenance expense. For example, if there is a resurgence of the virus during the flu season of late 2020 and into early 2021, the expenses may increase significantly.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 5

Question No. OCA 5-012-REV:

Please describe the impact of COVID-19 on operation and maintenance expense incurred in 2020 year to date.

Original Response:

Columbia estimates that from mid-March through May 31, 2020, it has incurred $485,342 of COVID-19-related operation and maintenance expense.

Updated:

While the Company's operations have been impacted by the Pennsylvania mandated changes in business operations, as well as by the need to change practices to ensure the safety of our customers and employees, it is currently Columbia's expectation and plan that the existing work plans and capital programs for 2020 will be completed in 2020, albeit on a modified schedule.

In mid-March accounting codes were established to track costs incurred by Columbia and the NiSource Corporate Services Company (NCSC) as a result of COVID-19 and that are incremental to usual practice. Through June 30, 2020 those charges total $738,417.13 and relate predominately to the acquisition of PPE, cleaning and sanitizing supplies, cleaning services, costs associated with working remotely as well as costs to ensure social distancing in areas where remote work is not possible.

At the same time, due to the Company requiring remote work where appropriate and social distancing, there has been a savings in employee expenses associated with temporary postponement of travel, meetings, etc. A comparison of year over year expenses during the period of April through June of 2020 and the same period in 2019 show a reduction of $450,187.44 for Columbia Gas of Pennsylvania and NCSC combined.

Due to the nature of other cost categories and timing of expenses and rescheduled work streams, an accurate identification of other potential savings will not be possible until the end of the year. It is not anticipated that significant savings from other cost categories (non-employee expenses) will be realized.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 5

Question No. OCA 5-004:

Referring to the response to OCA-II-22, please provide additional details of the forecasted increases in the number of employees in the FTY and FPFTY. The response should describe the particular functions and responsibilities of the additional employees and why these additional positions are necessary.

Response:

Related staffing increases are forecasted for construction (coordinators and specialists), gas operations, engineers, and trainers based on the Company's commitment for growth, compliance with safety standards on Low Pressure and Meter & Regulation, and maintaining priority measures with emergency response.

During the first quarter of 2019, the Company determined that in order to support the continued growth of its infrastructure replacement program and the Low Pressure Enhancement Program and maintain critical safety measures and oversight, additional personnel were required. To that end, the following additional complement was authorized:

M&R Technicians	11
M&R Leadership/Specialist	4
Construction Coordinators	34
Construction Specialists/Operations Coordinators	10
Construction Leadership	4
Welder	1
Training	4
Engineering	3

Job descriptions for each of these positions are included in OCA 5-004 Attachment A to this response.

The 59 vacancies listed as additional headcount during the FTY include 38 of the above positions that had not yet been ultimately filled, as well as 21 additional vacancies for positions that were open due to normal turnover – i.e., internal bidding on new positions or other vacancies, retirement, etc. (Note that internal job movement has a significant impact on the remaining vacancies at the end of any period.) Job descriptions for those vacancies not associated with the incremental positions are included in OCA 5-004 Attachment B to this response.

As indicated in the response to OCA 5-017, there are no additional positions currently planned for the FPFTY.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Office of Consumer Advocates – Set 5

Question No. OCA 5-017:

Referring to the response to OCA-II-48, please provide workpapers supporting the dollar amounts of the adjustments on Schedule 10. The referenced GASRR-026 shows the same amounts in tabular form, but does not have any support for the numbers.

Response:

During the compilation of the response to this data request and the response to OCA 5-004, it became apparent that there were errors in the budget data underlying the development of GAS RR-026, reflective of utilizing a version of the budget that was not final. A revised GASRR-026 is included as OCA 5-017 Attachment A and a revised Exhibit 104, Schedule No. 10 is included as OCA 5-017 Attachment B. The revised versions of each of these schedules corresponds to Columbia's current budgets and operating plans for the FTY and FPFTY. The residual impact of the revisions is an increase to the FPFTY labor expense of $8,415 and elimination of the additional headcount in the FPFTY.

The first adjustment of $3,012,122 reflects the annualization of HTY headcount, addressed by Company witness Miller at pages 9 and 10 of her testimony and shown on Exhibit No. 4, Schedule No. 2, Page 5.

The second adjustment of $624,145 reflects a projection of seven months of merit increase of 3%. Please refer to OCA 5-017 Attachment C for the calculation. Merit increases become effective at varying points of the year for non-exempt employees and historically on June 1st for exempt employees. Budgeting projections assume an average of 7 months overall. The O&M/capital ratio applied to the merit increase is based on ratio of O&M labor expense to total labor expense reflected in the current budget.

The third adjustment of $1,139,386 represents the O&M portion of labor expense for the 59 vacancies that existed at 11/30/19. OCA 5-017 Attachment D lists the vacancies, the assigned salary for each and the O&M/Capital split assigned based on the allocations associated with the departments where the vacancy resides and whether the position is exempt or non-exempt.

The current FTY Operations Work Plan anticipates overtime of $4.3 M, with approximately 70% in O&M and 30% in Capital work. The adjustment of ($1,300,000) is a comparison of the anticipated FTY Overtime vs. the experienced O&M Overtime in the HTY and reflects the planned reduction.

The final adjustment of $(1,845,154) represents the difference between the current FTY labor budget and the HTY labor once the known adjustments described above have been made. While it's not possible to show a calculation of that amount, it is reflective of the Company's intent to move toward greater utilization of Field Operations labor for capital construction activities, including new business installations, infrastructure replacement projects and abandonments, as well as changes in operational requirements for work on regulation facilities and system upgrades, which were reflected in the development of the Operations Work Plan.

Description	Pre-HTY TME 11/30/2018	HTY TME 11/30/2019	Additional Headcount	FTY TME 11/30/2020	Additional Headcount	FPFTY TME 12/31/2021
a.						
Employees						
Total Clerical Labor	84	90	0	90	0	90
Total Exempt Labor	144	167	15	182	0	182
Total Manual - Non-Union	16	14	2	16	0	16
Total Manual - Union	431	492	42	534	0	534
Total Employees	675	763	59	822	0	822

Description b.,c.,d., and e	Pre-HTY TME 11/30/2018	HTY TME 11/30/2019 Per Books	Annualization Adjustment	HTY TME 11/30/2019 Normalized	Additional Headcount	Merit @ 3%	OT Reduction/ Cap/O&M Change	Annualization Adjustment	FTY TME 11/30/2020 Normalized	Additional Headcount	Merit @ 3%	Annualization Adjustment	FPFTY TME 12/31/2021 Normalized
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(4)thru(8)	(9)	(10)	(11)	(12)=(9)thru(11)
Payroll Expense													
Regular Payroll	27,978,237	31,713,297	3,012,122	34,725,419	1,139,386	624,145	(1,845,154)	589,913	35,233,710	0	647,901	537,643	36,419,254
Overtime Payroll	4,433,371	4,362,259	0	4,362,259	0	0	(1,300,000)	0	3,062,259	0	0	0	3,062,259
Premium Payroll	50,723	58,413	0	58,413	0	0	0	0	58,413	0	0	0	58,413
Net Affiliate Labor Transferred	(246,522)	(3,779)	0	(3,779)	0	0	0	0	(3,779)	0	0	0	(3,779)
Total Expense	32,215,808	36,130,190	3,012,122	39,142,312	1,139,386	624,145	(3,145,154)	589,913	38,350,603	0	647,901	537,643	39,536,147
Capital Payroll													
Regular Payroll	21,201,740	22,554,724	2,277,818	24,832,542	2,762,756	553,487	1,845,154	491,556	30,485,495	0	574,554	449,574	31,509,623
Overtime Payroll	3,345,133	3,277,396	0	3,277,396	0	0	(2,300,000)	0	977,396	0	0	0	977,396
Premium Payroll	38,272	43,886	0	43,886	0	0	0	0	43,886	0	0	0	43,886
Net Affiliate Labor Transferred	(186,010)	(2,840)	0	(2,840)	0	0	0	0	(2,840)	0	0	0	(2,840)
Total Capitalization	24,399,135	25,873,167	2,277,818	28,150,985	2,762,756	553,487	(454,846)	491,556	31,503,938	0	574,554	449,574	32,528,066
Total Payroll	**56,614,943**	**62,003,357**	**5,289,940**	**67,293,297**	**3,902,142**	**1,177,633**	**(3,600,000)**	**1,081,469**	**69,854,541**	**0**	**1,222,454**	**987,217**	**72,064,212**
Incentive Comp													
Expense	1,521,149	1,472,179	4,354	1,476,533	0	0	0	403,467	1,880,000	0	0	387,000	2,267,000
Capital	1,191,460	1,131,161	(21,831)	1,109,330	0	0	0	557,840	1,667,170	0	0	343,189	2,010,358
Total Incentive Comp	**2,712,609**	**2,603,340**	**(17,477)**	**2,585,863**	**0**	**0**	**0**	**961,307**	**3,547,170**	**0**	**0**	**730,189**	**4,277,358**

Columbia Gas of Pennsylvania, Inc.
Labor Comparison
Normalized HTY to Per Books HTY to Budgeted FTY

			Comments
Normalized HTY (TME 11/30/19)	**$**	**39,142,312**	Per Exhibit 104 Schedule 1 Page 3
Ratemaking Adjustments		(3,012,122)	Per Exhibit 4 Schedule 2 Page 1
Per Books HTY (TME 11/30/19)	**$**	**36,130,190**	Per Exhibit 4 Schedule 1 Page 2
Budget Adjustments			
Headcount at beginning of FTY	$	3,012,122	To reflect full year of additional headcount added throughout HTY
Merit increase		624,145	3% increase over HTY Budget effective June 1
Additional Headcount		1,139,386	Additional headcount in Gas Operations/Construction/Engineering/Training
Planned OT Reduction		(1,300,000)	To reflect anticipated OT in FTY Work Plan
Shift in O&M/Cap allocation		(1,845,154)	Reflects nature of incremental positions plus increase capital work planned for Field Ops personnel
	$	**1,630,499**	
Budgeted FTY Labor (TME 11/30/20)	**$**	**37,760,689**	Per Exhibit 104 Schedule 1 Page 3

Columbia Gas of Pennsylvania, Inc.
Labor Comparison
Normalized FTY to Budgeted FTY to Budgeted FPFTY

		Comments
Normalized FTY (TME 11/30/20)	**$ 38,350,603**	Per Exhibit 104 Schedule 1 Page 3
Rate Making Adjustments	589,913	Per Exhibit 104 Schedule 1 Page 3
Budgeted FTY (TME 11/30/20)	**$ 37,760,689**	Per Exhibit 104 Schedule 1 Page 3
Budget Adjustments		
	589,913	Annualization to reflect full year of merit awarded 6/1/20
Merit increase	647,901	3% increase over FTY Budget effective 6/1/21
	$ 1,237,814	
Budgeted FPFTY Labor (TME 12/31/21)	**$ 38,998,503**	Per Exhibit 104 Schedule 1 Page 4

OCA 5-017
Attachment C

HTY Total Normalized Payroll Expense	$67,293,297.00
7 months of 3% annual merit increase	1.75%
Projected Merit for Employees at 11/30/19	$1,177,632.70
O&M ratio reflected in current budget	53.00%
Projected O&M allocation of FTY merit increase	$624,145.33

Vacancies at 11/30/19		O&M Allocation	Capital Allocation	O&M $	Capital $
Assoc Field Eng 2 (00012009)	$63,599	0.037	0.963	$2,353	$61,246
Compliance Specialist 2 (00010680)	63,599	0.085	0.915	5,406	58,193
Constr Operations Coordinator (00011999)	39,075	0.085	0.915	3,321	35,754
Constr Operations Coordinator (00013185)	39,075	0.085	0.915	3,321	35,754
Constr Operations Coordinator (00013186)	39,075	0.085	0.915	3,321	35,754
Constr Operations Coordinator (00013187)	39,075	0.085	0.915	3,321	35,754
Construction Coordinator (00011186)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013144)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013145)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013149)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013160)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013161)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013162)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013164)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013167)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013168)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013171)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013176)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013177)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013178)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013179)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator (00013180)	75,462	0.085	0.915	6,414	69,048
Construction Coordinator 1 (00013181)	58,607	0.085	0.915	4,982	53,625
Construction Coordinator 1 (00013182)	58,607	0.085	0.915	4,982	53,625
Construction Coordinator 1 (00013183)	58,607	0.085	0.915	4,982	53,625
Construction Equip Operator (00005758)	58,282	0.085	0.915	4,954	53,328
Construction Equip Operator (00005878)	58,282	0.085	0.915	4,954	53,328
Construction Equip Operator (00005927)	70,803	0.085	0.915	6,018	64,785
Construction Specialist (00009867)	58,607	0.085	0.915	4,982	53,625
Construction Specialist (00013152)	58,607	0.085	0.915	4,982	53,625
Construction Specialist (00013153)	58,607	0.085	0.915	4,982	53,625
Construction Specialist (00013154)	58,607	0.085	0.915	4,982	53,625
Construction Specialist (00013156)	58,607	0.085	0.915	4,982	53,625
Equipment Operator (00008640)	59,322	0.624	0.376	37,017	22,305
Field Engineer (00013241)	76,812	0.037	0.963	2,842	73,970
Field Ops Apprentice Tech (00005585)	45,760	0.624	0.376	28,554	17,206
Ldr Front Line System Ops C&L (00009618)	74,571	0.604	0.396	45,041	29,530
Lead Regulatory Compliance (00008646)	55,512	0.604	0.396	33,529	21,983
Leader Field Operations (00005869)	74,571	0.604	0.396	45,041	29,530
Leader Front Line Constr Serv (00013142)	74,571	0.085	0.915	6,338	68,232
Leader M&R (00005568)	74,571	0.604	0.396	45,041	29,530
Leader M&R (00013112)	74,571	0.604	0.396	45,041	29,530

Vacancies at 11/30/19		O&M Allocation	Capital Allocation	O&M $	Capital $
Locator Technician (00005921)	56,222	0.624	0.376	35,083	21,140
M & R Technician Sr (00005717)	75,067	0.624	0.376	46,842	28,225
M&R Specialist 1 (00013110)	56,348	0.624	0.376	35,161	21,187
M&R Specialist 1 (00013111)	56,348	0.624	0.376	35,161	21,187
M&R Specialist 2 (00011199)	68,667	0.624	0.376	42,848	25,819
Plant Specialist (00005753)	75,296	0.624	0.376	46,985	28,311
Plant Specialist (00006944)	75,296	0.624	0.376	46,985	28,311
Plant/Service Specialist (00005605)	64,189	0.624	0.376	40,054	24,135
Plant/Service Specialist (00005750)	76,752	0.624	0.376	47,893	28,859
Plant/Service Specialist (00005906)	76,752	0.624	0.376	47,893	28,859
Plant/Service Technician (00005696)	76,752	0.624	0.376	47,893	28,859
Plant/Service Technician (00005815)	76,752	0.624	0.376	47,893	28,859
Safety & Health Coordinator 3 (00002941)	72,658	0.627	0.373	45,556	27,101
Tech GIS/GPS Quality Control (00009887)	47,154	0.639	0.361	30,131	17,023
Utility Representative (00005687)	54,662	0.624	0.376	34,109	20,553
Utility Representative (00009915)	54,662	0.624	0.376	34,109	20,553
Welder Senior (00009074)	81,162	0.085	0.915	6,899	74,263
	$3,902,116			$1,139,392	$2,762,724

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-018:

Reference Columbia Exhibit No. 104, Schedule 1, p. 3, and Schedule 11, p. 1, concerning Normalized HTY to Budgeted FTY outside services. Provide the basis and calculation of budget adjustments of $(1,167,799).

Response:

The occurrence of two significant Outside Service expenses recorded in the HTY and subsequently reversed in December, 2018 (FTY) causes Exhibit 104, Schedule No. 11 to depict a roundabout walk-across between the two test periods. Attachment A to this data request adjusts the test year expenses for those two specific items to provide a more straightforward identification of the drivers of the difference between the actual expenditures related to the HTY and those budgeted for in the FTY.

The first of the two expenses subject to reversal represented costs incurred by the Company in restoration activities associated with an outage in January. Columbia sought and received reimbursement for $385,775 of the costs from a 3rd party involved in the outage. That reimbursement was recorded in December, 2019 as a credit to Outside Services, leaving the HTY overstated and the FTY understated.

The second expense subject to reversal related to Service Line Installation costs that were being charged to expense rather than to the capital job orders associated with facilities being installed. The error was discovered and after a thorough analysis to identify all instances, an adjustment was made to properly reclassify $195,738 from O&M expense to capital investment. Again, as in the instance described above, the correcting entry was made in December 2019, leaving the level of expense in the HTY overstated and the FTY understated.

Removing the costs for both occurrences from the HTY and the credits from the FTY, leaves comparable levels of expense. The difference between the two adjusted test year expenses are then explained.

As stated in my testimony, non-labor expenses start with the assumption that amounts are to be held relatively flat year to year reflecting normal, ongoing level of expense and further adjusted for incremental activities that are reasonably expected to occur or adjusted for expenses that are not expected to recur.

On Attachment A, page 1 of 2, I have identified the significant expenses in the HTY that are not expected to recur in the FTY. After consideration of these, the adjusted FTY budget represents an increase of 1.4% over the adjusted HTY expenses. This variance is not identifiable to a specific work stream or activity, but rather results from comparing a FTY of one-month of actual and 11 months of projected expenses with 12 months of actual data in the HTY.

Columbia Gas of Pennsylvania, Inc.
Analysis of Change in Outside Services Expense HTY to FTY
Adjusted Per Books HTY to Adjusted Budgeted FTY

			Comments
Per Books HTY (TME 11/30/19)	**$**	**23,300,011**	Per Exhibit 4 Schedule 1 Page 2
		(385,775)	Removal of costs incurred in HTY for January 2019 service outage subsequently reimbursed by 3rd pary
		(195,738)	Removal of capital Service Line installation expenditures erroneoulsy recorded as O&M, subsequently reversed in December 2019
Adjusted HTY Outside Services Expense (TME 11/30/19)	**$**	**22,718,498**	**(A)**
Budgeted FTY Outside Services (TME 11/30/20)	**$**	**21,582,000**	
		385,775	Reverse December 2019 credit for 3rd party reimbursment of service outage costs
		195,738	Reverse December 2019 credit for reclassification of Service Line Installation expenditures erroneously expensed.
Adjusted Budgeted FTY Outside Services Expense (TME 11/30/20)	**$**	**22,163,513**	**(B)**

Columbia Gas of Pennsylvania, Inc.
Analysis of Change in Outside Services Expense FTY to FPFTY
Adjusted Budgeted FTY to Adjusted Budgeted FPFTY

		Comments
Adjusted FTY Outside Services Expense (TME 11/30/20)	**$ 22,163,513**	
Budgeted FPFTY Outside Services - (TME 12/31/21)	**$ 24,189,000**	
Budget Increase	**$ 2,025,487**	Increased funding for incremental corrosion remediation, company owned field assembled riser replacement, restoration contract cost increases, underground facility audit and remediation, MAOP compliance costs, increasing line locate volumes.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Bureau of Investigation & Enforcement – Set RE

Question No. I&E-RE-019:

Reference Columbia Exhibit No. 104, Schedule 1, p. 3, and Schedule 11, p. 2, concerning Normalized FTY to Budgeted FPFTY outside services. Provide the basis and calculation with a breakdown of budget adjustments of $251,621.

Response:

As noted in the Company's response to I&E-RE-18, Attachment A to that data request was developed to provide a straightforward comparison of the FTY and FPFTY budgets after adjusting the FTY for the reimbursement of HTY expenses.

I&E-RE-018 Attachment A shows the simple mathematical comparison of the adjusted FTY budget and the FPFTY budget for Outside Services for an increase $2,025,487 and associates the increase as a whole to a number of discreet workstreams. Emerging field conditions discovered and new regulatory requirements in the FTY will influence the precise work plan ultimately designed for the FPFTY, and therefore the specific budgets for each activity. The following are some specific workstreams anticipated to be allocated incremental funding in the FPFTY over the FTY:

- underground storage well inspection and remediation activities, in response to the PHMSA regulations on Minimum Safety Standards for Underground Storage Fields effective March 13, 2020 requiring a baseline risk assessment within 4 years. Inspections are planned to be initiated in the third and fourth quarters of 2020, with completion and resultant remediation projects included in subsequent periods;
- Maximum Allowable Operating Pressure (MAOP) reconfirmation/ documentation of the Company's facilities to comply with PHMSA safety regulation amendments issued in 2019, effective July 1, 2020;

- corrosion remediation, which allows the Company to proactively identify and remediate corrosion to minimize and manage facilities that would otherwise degrade to unsatisfactory condition;
- GPS legacy and remediation programs that consistently enhances the Company's ability to locate system facilities;
- allowance for increases in contractor rates for restoration services associated with leak repair:
- allowance for increasing line locating costs driven by year over year trending ticket volume increases.

Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2020-3018835

Responses of the Bureau of Investigation and Enforcement to Columbia Gas of Pennsylvania, Inc. Interrogatories Set II
Witness: John Zalesky

Columbia to I&E-II-1 — Reference page 20, line 18 through page 21, line 2, of I&E Statement No. 1, the Direct Testimony of John Zalesky. Please explain how the current pandemic may cause the upcoming PUC, OCA, OSBA assessment to be lower than the current assessment, and include, as available, any insight into the proposed PUC, OCA and OSBA budgets for the fiscal year of July 1, 2020 - June 30, 2021.

Response: **Mr. Zalesky did not state nor imply that the current assessment will be adjusted or affected by the pandemic as the current assessment factors will be based on natural gas gross revenues reported via annual assessment reports for the year ended December 31, 2019 and the 2020-2021 PUC/OSBA/OCA/DPC annual budgets as finalized earlier this year. However, future budgets could be affected by modifications to operations that may reduce budgets due to long-term impacts to operations such as potential extended travel restrictions, and it would be inappropriate to embed an amount for assessments in base rates that may never be realized before the Company's next base rate case.**

Columbia Gas of Pennsylvania, Inc.
Labor Comparison
Normalized HTY to Per Books HTY to Budgeted FTY

			Comments
Normalized HTY (TME 11/30/19)	**$**	**39,142,312**	Per Exhibit 104 Schedule 1 Page 3
Ratemaking Adjustments		(3,012,122)	Per Exhibit 4 Schedule 2 Page 1
Per Books HTY (TME 11/30/19)	**$**	**36,130,190**	Per Exhibit 4 Schedule 1 Page 2
Budget Adjustments			
Headcount at beginning of FTY	$	3,012,122	To reflect full year of additional headcount added throughout HTY
Merit increase		624,145	3% increase over HTY Budget effective June 1
Additional Headcount		1,139,386	Additional headcount in Gas Operations/Construction/Engineering/Training
Planned OT Reduction		(1,300,000)	To reflect anticipated OT in FTY Work Plan
Shift in O&M/Cap allocation		(1,845,154)	Reflects nature of incremental positions plus increase capital work planned for Field Ops personnel
	$	**1,630,499**	
Budgeted FTY Labor (TME 11/30/20)	**$**	**37,760,689**	Per Exhibit 104 Schedule 1 Page 3

Columbia Gas of Pennsylvania, Inc.
Labor Comparison
Normalized FTY to Budgeted FTY to Budgeted FPFTY

		Comments
Normalized FTY (TME 11/30/20)	**$ 38,350,603**	Per Exhibit 104 Schedule 1 Page 3
Rate Making Adjustments	589,913	Per Exhibit 104 Schedule 1 Page 3
Budgeted FTY (TME 11/30/20)	**$ 37,760,689**	Per Exhibit 104 Schedule 1 Page 3
Budget Adjustments		
	589,913	Annualization to reflect full year of merit awarded 6/1/20
Merit increase	647,901	3% increase over FTY Budget effective 6/1/21
	$ 1,237,814	
Budgeted FPFTY Labor (TME 12/31/21)	**$ 38,998,503**	Per Exhibit 104 Schedule 1 Page 4

COLUMBIA STATEMENT NO. 11-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

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

August 26, 2020

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 Manager of Regulatory Accounting 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" "CPA" or the "Company"), which is one of the NiSource local distribution companies.

Q. Have you previously filed testimony in this matter?

A. Yes.

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"), and Mr. Knecht, witness for the Office of Small Business Advocate ("OSBA"), on the subject of the Allocated Cost of Service Studies ("ACOSS").

Q. The Company presented three separate ACOSS (Customer/Demand, Peak & Average, and Average Study). Please explain why three studies were prepared and why you believe it is the average study that should be principally relied upon 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 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.

It is broadly accepted that a single allocated cost of service study cannot and should not be relied upon to determine the exact cost to serve each class of customers. The National Association of Regulatory Utility Commissioners, in its June 1989 Gas Distribution Rate Design Manual, stated that "there is no one correct cost of service, but rather a range of reasonable alternatives." Clearly, if Columbia or any other party to this case were to simply choose a single study as the basis for allocating costs, doing so would produce an outcome that unfairly favors or disfavors a specific class of customers.

Columbia submitted three studies because of the very real understanding that no single study by itself can give an accurate determination of rate class cost of service to be used as a basis of revenue responsibility for each rate class.

Q. Please describe the primary differences among the three studies submitted by Columbia in this proceeding.

A. Columbia prepared and submitted a Customer/Demand Study, a Peak & Average Study, and an Average Study. With all three studies, the allocation of costs is essentially the same, with the exception of the allocation of mains.

The Customer/Demand Study weights the allocation of mains using a factor based on the number of customers (Customer) and the company's peak day design (Demand). This method recognizes the customer number component of mains.

In the Peak & Average Study, the allocation of mains uses a factor weighting 50% to the Company's peak day design (Peak), and 50% to the Company's throughput (Average).

As stated above, the Average Study gives equal weight to the Customer/Demand and the Peak & Average methods.

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

A. Witness Cline based his determination of rate class revenue requirement on the Company's Peak & Average Study, referring to the Commission's orders in National Fuel Gas Distribution Company's 1994 base rate proceeding, and

Philadelphia Gas Works case at Docket No. R-00061931, Order entered September 28, 2007.

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

A. Witness Mierzwa prefers a modified version of the Company's Peak & Average Study, where he eliminates the Company's separation of mains investment by operating pressure, 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. He states on pages 16 and 17 of his direct testimony: "Since distribution mains exist to deliver annual requirements, and are sized to provide for peak requirements, it is proper to allocate distribution mains costs on the basis of Peak & Average demands, consistent with established Commission precedent."

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

A. Witness Knecht recommended, on page 27 of his direct testimony, a weighted average cost of service study which weights 75% of the Company's Peak & Average Study and 25% of its Customer/Demand Study. He states two reasons in support of this method: 1) the results of his independent ACOSS in the Company's 2012 rate case were generally closer to the results of the Peak & Average Study than the Customer/Demand Study; and 2) "the P&A ACOSS is conceptually more similar to the A&E (Average & Excess) methodology that the Commission has approved for gas distribution utilities."

Q. How do the positions of the parties differ from yours?

A. As previously mentioned, a combination of preferences exists among the parties as to which distribution mains allocation method they prefer. Witness Mierzwa and Witness Cline both recommend the use of the Peak & Average Study, however Witness Mierzwa preferred to modify the Company's Peak & Average Study to eliminate the Company's separation of mains investment by operating pressure, whereas Witness Cline relied solely on the Company's Peak & Average study. Witness Knecht recommends a study that incorporates a customer component of allocation. Witness Knecht's position most closely matches Columbia's preference to use a study that includes both a customer and throughput component, though his recommendation is to apply a smaller weighting to the customer component. The positions of Witnesses Cline and Mierzwa markedly differ from Columbia's preferred approach, in that their studies include the throughput component in lieu of the customer component.

Q. Does the Company agree with Mr. Cline and Mr. Mierzwa that throughput determines 50% of the amount of main investment?

A. No. 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. The simple fact is that customer throughput has no impact on the determination of the size, length, or cost of the distribution main serving the customer. Customer throughput is simply a measurement of the utilization of the distribution main and as such is a factor in the customer's decision of selecting gas service. In other words, the availability of receiving gas service 365 days a year is a reason the customer requests gas service and causes the gas distribution company to invest in the purchase and installation of gas mains but has nothing to do with Columbia's incurred cost of the pipe or the cost of installing the gas main to provide service to the customer.

Q. Do you agree with Mr. Mierzwa when he states on page 11 of his direct testimony "Distribution mains are not sized for the number of customers served from them, but for the loads placed upon them"?

A. No. The "size" of a distribution main is its length and its diameter. The length of the distribution main is determined by the distance a distribution main must be extended to connect the customer to the existing distribution system or transmission pipeline. The cost to extend the distribution main is based on the Company's obligation to serve, as defined by its line extension policy. The policy dictates the maximum feet of main that the Company must provide without charge to the customer. That portion of main is directly related to the customer for whom the main is installed. The more customers added, unless added to an existing main, the longer the main, and the longer the main, the more dollars invested by the Company. In the case of adding a new customer to an existing distribution main, the Company may still incur additional costs by virtue of contribution refunds if the Company has a line extension agreement with an existing customer where the customer had made a deposit for the line extension with the agreement that, as additional customers are added, the Company would refund a portion of the deposit paid by the existing customer.

As for the diameter of the main, this is determined by the demand requirements of the Company's customers that it must be able to serve at design day temperatures. So it is the combination of the cost to extend a distribution main (customer component) and the cost of the diameter of the pipe to serve customers at design day temperatures (demand component) that determines the causation of the cost of the main, and not the service received by its customers during all other times of the year (throughput).

Q. What information did Mr. Mierzwa use to dispute Columbia's position that number of customers served have a direct cost causation to footage of mains pipe?

A. Mr. Mierzwa relied primarily on three arguments to dispute Columbia's position that number of customers served have a direct cost causation to footage of mains pipe. First he referenced the footage between Columbia's top 10 customers and the next closest upstream customer; second, he gave a hypothetical example of customer density; and third, he cited a quote from Professor James Bonbright.

Q. What conclusion did Mr. Mierzwa make about the top 10 customers Columbia serves?

A. Table 2 of his direct testimony shows the 10 largest non-MLS/MLDS customers that Columbia serves. Mr. Mierzwa then concludes on page 12 of his direct testimony that "Table 2 clearly demonstrates that CPA's allocation of distribution mains investment based on the number of customers, which assigns the same number of feet of distribution mains to each customer, does not result in a reasonable allocation of costs."

Q. Do you agree with Mr. Mierzwa that the range in footage of pipe between each of the top 10 customers and the next closest upstream customer demonstrates that CPA's allocation of distribution mains investment based on the number of customers, which assigns the same number of feet of distribution mains to each customer, does not result in a reasonable allocation of costs?

A. No. What Mr. Mierzwa is referring to is when the number of customers served is used as an allocation factor, the 10 largest customers would be allocated the same amount of mains cost as would the 10 smallest customers. Applying Mr. Mierzwa's logic, for the 12 months ending November 30, 2019, the equal footage would amount to 93 feet per customer (40,409,960 feet / 432,698 customers).[1] The actual average footage of pipe for 9 of the 10 largest customers shown with footage is 2,559 feet.

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[1] Exhibit CEN-2, Page 43, Line 10 and Page 53, Line 9.

If Columbia were to rely solely on number of customers in the allocation of the cost of mains, Mr. Mierzwa would be correct: that is, the 10 largest customers would not be allocated enough cost. However, Columbia does not rely solely on number of customers to allocate mains costs. Transmission class mains are allocated on design day volumes. In the Customer/Demand Study, only 49% of low pressure mains, 59% of regulated pressure mains, and 31% of remaining regulated pressure mains are allocated based on number of customers. Number of customers is not a factor in Columbia's Peak & Average Study. As a result, the Average Study that Columbia ultimately uses as a basis of revenue allocation to the rate classes only allocates 25% of low pressure mains, 29% of regulated pressure mains, and 16% of remaining regulated pressure mains based on number of customers.

On the other hand, Mr. Mierzwa's Peak & Average study allocates 50% of mains cost based on throughput and 50% on design day. Working with the same 9 of the top 10 customers, the average throughput for the 12 months ending November 30, 2019 is 1,032,651 Dth (9,293,862 / 9). The average design day demand is 3,712 Dth (33,410 / 9). Total throughput, excluding MLS/MLDS, is 78,588,715 Dth[2] and total design day demand is 792,523 Dth[3]. The average number of feet of distribution mains that Mr. Mierzwa's Peak & Average study assigns to the 9 customers is 360,128 feet (((1,032,651 Dth / 78,588,715 Dth) x 50% + (3,712 Dth / 792,523 Dth) x 50%) x 40,409,960 feet).

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[2] Exhibit CEN-2, Page 14, Line 13.
[3] Exhibit CEN-2, Page 14, Line 16.

When it comes to the assignment of mains cost for the 10 largest customers, Mr. Mierzwa makes a point that the 10 largest customers would receive an under allocation of cost if only number of customers were used as a basis of allocation. In fact, Columbia effectively only uses a weighting of 16% to 29% of the allocation of mains costs based on number of customers. However, clearly Mr. Mierzwa's Peak & Average study grossly over allocates mains costs by effectively assigning the cost of 360,128 feet (more than 68 miles) of pipe on average to 9 of the 10 largest customers.

Q. Mr. Mierzwa states on page 11 of his direct testimony that "Distribution mains are not sized for the number of customers served from them, but for the loads placed upon them." He then cites an example that he believes makes his point clear. What is the example that he gives and does his example prove his statement to be true?

A. The example given is as follows: Located along one city block are ten residential customers with a coincident peak demand of one dekatherm ("Dth") each. The distribution main running down the street would have to be capable of delivering 10 Dth at peak. On another city block is only one small plastics factory that exhibits a maximum demand of 10 Dth. Finally, imagine that the plastics factory is torn down to make room for five large residences, each of which exhibits a demand at time of coincident peak of 2 Dth. Again, the main that is sized to deliver 10 Dth is adequate. Mr. Mierzwa asserts that "the existence of one customer, five customers, or ten customers does not determine the amount of mains investment; rather, mains investment is a function of the loads to be served."

Columbia believes Mr. Mierzwa is only partly correct. The amount of mains investment made by the company depends on the cost to extend the main to the new customer, the cost of the capacity required by the new customer, and the incremental revenue the new customer will provide to recover, over time, the incremental cost and a contribution toward overhead and return.

First, in Mr. Mierzwa's example, he only discusses peak demand. Columbia agrees that peak demand is a causation of cost and that is why Columbia uses peak demand (design day demand) in all three of its allocated cost of service studies. Peak demand is the determination of the diameter of the main; in the Customer/Demand Study, it is the demand component.

In Mr. Mierzwa's example, he assumes that both streets are one block long. I, in turn, assume he intended to infer that the capital investment on both streets was the same. Under the Company's line extension policy there must be enough incremental revenue from the new customers to provide recovery, over time, of the incremental cost and a contribution toward overhead and return. Using current rates, the street with the 1 commercial customer will contribute toward revenue $66.90 [(10 Dth x $4.415/Dth) + ($22.75 customer charge x 1 customer)]. The street with the 10 residential customers will contribute toward revenue $228.26 [(10 Dth x $6.076/Dth) + ($16.75 customer charge x 10 customers)] Consequently because the commercial customer only contributes $66.90 toward the recovery of the mains investment and the 10 residential customers contribute $228.26, the commercial customer would most likely be required to make a contribution in aid of construction

("CIAC") toward the mains investment on its street where there would be no requirement of a CIAC for the 10 residential customers. So under this example, the mains investment made by the Company for the 1 commercial customer is significantly less than the mains investment made by the Company for the 10 residential customers because the commercial customer would most probably be required to pay a CIAC to compensate for the amount of the Company's mains investment.

Q. Witness Mierzwa relies on reference materials from Professor James Bonbright to support his conclusion that it is improper to allocate a portion of mains on the basis of being customer-related. Does Professor Bonbright provide any opinion supporting the allocation of a portion of mains on the basis of being customer-related?

A. Yes. Professor James Bonbright firmly states the appropriateness of the recognition of a customer component of distribution mains for cost allocation in his book, Principles of Public Utility Rates.[4] On pages 400-401, he refers to the use of the two-part Hopkinson[5] rate structure, which is based on the assumption that, part of the total cost of a utility's business is a function of the output or energy of the system and the other part is a function of plant and equipment capacity and all costs associated with this capacity. Professor Bonbright continues on page 401 by noting that "this two-fold distinction fails to acknowledge that a material part of the

[4] Principles of Public Utility Rates, Second Edition, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, Public Utility Reports., 1988.
[5] Dr. John Hopkinson, a British electrical-utility engineer, introduced a two-part rate composed of an energy charge and a demand charge.

operating and capital costs of a utility business is more directly and closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other."

Furthermore, on page 401Professor Bonbright says that:

> customer costs are invariant with respect to consumption. They are the costs incurred to serve a customer even if the customer does not use the service at all. The most obvious examples of these customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing and accounting, and a portion of the distribution system.

Lastly, on page 492, he states that "In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts."

Q. Are there any other recognized authorities who agree that it is proper to include a customer component in the distribution mains allocation?

A. Yes. Dr. Charles F. Phillips, Jr., in The Regulation of Public Utilities,[6] states on page 406 that "customer costs vary with the number of customers. These costs include a portion of the distribution system, local connection facilities, metering equipment, billing and accounting. Customer costs, moreover, are independent of consumption."

Also, the American Gas Association published Gas Rate Fundamentals,[7] in which it is stated that customer-related costs are primarily distribution and customer accounting costs. Among other things, it is also stated on page 136 that:

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[6] The Regulation of Public Utilities, Charles F. Phillips, Jr., Public Utility Reports, 1984.
[7] Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987.

> the closer a plant item (e.g., a meter and service line) is located to a customer, the more that particular item is related to the specific requirements of that customer. Thus, the customer component of distribution costs reflects the theoretical distribution system that would be needed to serve customers at nominal or minimum load conditions.

In regard to the many different functions and cost causative components attributable to the gas distribution operations, these authorities support the concept that the main cost causation component for distribution costs is one that is customer-related.

Q. Mr. Mierzwa points out on page 15 of his direct testimony that CPA has increased its investment in distribution mains by nearly $1.3 billion since 2003, which represents an increase of 350 percent in mains investment, but the number of customers served has only increased approximately 8.5 percent. He claims that this supports his argument that increased investment in distribution mains is not related to the increase in number of customers. Do you agree?

A. Mr. Mierzwa is basing his assumption on the fact that a great deal of recent investment is in the replacement of mains due to age and condition. In the instance of mains replacement investment, neither customer counts nor throughput necessarily increase and neither does design day demand. However, Mr. Mierzwa's suggested "throughput basis" of mains allocation seems to have an even weaker relationship to the increase in mains investment. When looking at throughput for the same period, throughput dropped from 87,100,595 Mcf to 78,588,715 Dth since 2003 or (10%).

Q. On page 16 of his direct testimony, Mr. Mierzwa refers to an article in *Public Utilities Fortnightly* entitled "The Customer Charge and Problem of Double Allocation of Costs" by George J. Sterzinger published in July 2, 1981, as justification for a Residential demand credit, stating that "Failing to provide a demand credit results in a double allocation of costs to Residential customers". Do you have any comment on the article?

A. Yes. Mr. Sterzinger states the following in his article when referring to minimum sized equipment:

> So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-killowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

Mr. Sterzinger, like Mr. Mierzwa, assumes that the entire requirements of a residential customer can be accommodated by the minimum-sized equipment and, because of that, the residential class should not contribute toward the cost of facilities that are larger in size than the minimum sized system and to do so would constitute a "double allocation of cost". However, Mr. Sterzinger fails to address the facts that most residential customers are served downstream from larger sized facilities and that a large percent of residential customers are served off larger diameter pipe because they are served from a low pressure system. The use of upstream larger diameter pipe to serve the residential class is the most efficient and economical means to deliver gas to customers. If a residential demand credit were used in the allocation of mains investment, it would result in a severe under-allocation of the capacity that the larger diameter pipe provides to the residential class. I would also observe that Mr. Sterzinger's article concerns electric distribution facilities, and Pennsylvania uses a customer component in the allocation of electric distribution facilities. Finally, it is important to note that the current residential customer charge of $16.75 that Mr. Mierzwa proposes the Company maintain, does not recover any mains investment, much less mains capacity investment caused by load requirements.

Q. Mr. Mierzwa states on page 16 of his direct testimony "mains investment is undertaken when annual gas consumption is high enough to warrant the investment". Do you agree?

A. Yes, as long as rate design includes a volumetric base rate. I believe Mr. Mierzwa is referring to the Company's main extension policy where annual demand and associated revenues are factors considered in Columbia's main extension investment decision of whether to extend a gas main to a new customer.

The Company's main extension policy takes into account the incremental costs to serve a new customer. Mains costs are based upon the capacity level necessary to meet the new customer's peak hour demand (design day demand component) and the length of pipe required to extend the existing gas main to the new customer (customer component). Expected annual revenue from the new customer has to economically justify the line extension to the new customer. Because current rate design includes both a customer charge and a volumetric rate per dekatherm, the new customer's annual consumption has to be high enough to warrant the investment. Mr. Mierzwa is attempting to justify cost causation on the basis of the Company's existing rate design.

Q. What impact would throughput have on Columbia's main extension investment decision-making if current rate design was recovering all costs through the fixed monthly customer charge?

A. None. Removing throughput as a factor in the generation of revenue recovery of mains investment would eliminate throughput as a factor in the decision making to extend the gas main. In other words, throughput has no impact on the determination of the cost of the mains extension, throughput only impacts the economic feasibility of the line extension because of current rate design.

Q. Throughout Mr. Mierzwa's direct testimony he discusses "the principle of cost causality" where above in your testimony you discuss the "principle of cost causation". Is there a difference?

A. Yes. Mr. Mierzwa describes his principle of cost causality on page 19 of his direct testimony stating:

> Because costs are incurred to deliver gas generally throughout the year, and additional costs are incurred to meet peak demands, CPA's distribution mains costs must be allocated on the basis of both annual and peak demands if those costs are to be allocated in accordance with the principle of cost causality.

Mr. Mierzwa's principle of cost causality refers to the <u>reason</u> customers request gas service. That is, the customer requests gas service so that the customer can utilize that service 365 days a year, regardless of the weather. Mr. Mierzwa theorizes that the utility installs gas mains because the customer requests service and the customer would only request service if he or she can utilize the service 365 days a year and, therefore, what "causes" the utility to incur additional costs (make additional investment in mains) is the utilization of the gas mains during peak demand and throughout the year. According to Mr. Mierzwa, it then follows that, because utilization of the gas main causes the cost of the main, the cost of the main should be recovered on a volumetric basis (ie. via a volumetric base rate).

Quite in contrast, the principle of cost causation is based on <u>cost incurrence</u>. In other words, what are the costs that the Company incurs to build the gas mains to serve the requirements of each customer? There are two fundamental causes of mains cost: 1) cost is incurred as the Company extends the gas main to attach the new customer to the distribution system; and 2) capacity cost is incurred to meet maximum hourly gas flow requirements. It follows that, because the Company incurs cost each time the Company extends a gas main for a new customer, at a minimum, a portion of the mains cost equal to the cost of a minimum size pipe should be recovered from each customer, regardless of the customer's demand. It also follows that the capacity-related costs incurred by the Company for installation of pipe in excess of the minimum size pipe should be recovered either through a demand charge or a fixed monthly charge.

Q. Is the Company saying that the Peak & Average Study should not be used in the determination of rate class revenue requirement?

A. No. As previously stated, the Company believes the Peak & Average Study should be used to establish the "range of reasonableness," but that the Average Study appropriately sets the basis of rate class revenue requirement. What the Company is stating, though, is that the Peak & Average Study is based on the utilization of the distribution mains system. Because 50% of the Peak & Average Study is based on throughput, it does not reflect the manner in which the Company actually incurs costs to provide service. The Company's Customer/Demand Study does reflect the manner in which the Company actually incurs costs to provide service, commonly known as cost causation, and that is why the Company applies equal weight to both the Peak & Average and Customer/Demand Studies in the determination of rate class revenue requirement.

Q. Witnesses Mierzwa and Cline reference the 1994 National Fuel Gas Distribution Corporation ("NFGD") base rate proceeding when supporting their respective arguments 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. I have reviewed the 1994 NFGD case and have found a significant difference between that case and Columbia's current case. In its Final Order in the case, the Commission described the NFGD Cost of Service Study on page 208 as follows:

> NFG has presented two separate cost of service studies in this proceeding. Its preferred study, found at NFG Exhibit Nos. 111-1 (present rates) and 111-2 (proposed rates), separates distribution mains into large and small categories for cost allocation purposes, and uses a peak and average allocation methodology. The alternate study, found at NFG Exhibit Nos. 111-3 (present rates) and 111-4

> (proposed rates) also uses the peak and average methodology, but makes no distinction among mains, treating all main sizes equally for allocation purposes.

From this summary, it is clear that NFGD only submitted studies based on the Peak & Average methodology. In its ruling, the Commission, as Witness Cline noted in his direct testimony on page 17, stated "[t]he Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact."

In its ruling, the Commission was obviously choosing between two slightly different Peak & Average studies.

On page 215 of the order the Commission stated "NFG's proposed small mains adjustment suffers from the same weaknesses that we have previously found required the rejection of other alternatives to a Peak and Average cost of service study." The Commission then cited *Pa. P.U.C. v National Fuel Gas Distribution Corp.*, 1990 Pa. PUC Lexis 146 (Docket No. R-901670) and *Pa. P.U.C. v. Peoples Natural Gas Co.*, 1987 Pa. PUC Lexis 339 as two supporting cases.

In the 1990 *Pa. P.U.C. v National Fuel Gas Distribution* case, National Fuel Gas supported an allocated cost of service study constructed by the Peak & Average method, but employed a customer cost component of mains as well as a demand cost component. In its Opinion and Order on page 185, the Commission noted:

> [T]he ALJ is persuaded that the allocation of the costs related to distribution mains should reflect a customer component in these costs. The ALJ states that "Clearly, the cost of mains is affected by the total length of pipe used in their construction, and the Company has presented clear evidence indicating a positive relationship

> between miles of distribution mains and the number of customers on the system." ***
>
> For these reasons, the ALJ believes the Company's P&A cost of service study utilizing a customer component of distribution mains costs is reasonable as a guide to revenue allocation and rate design in this proceeding, and recommends its adoption for this purpose.

After considering the various parties' positions, the Commission concluded on page 191:

> On the other hand, the OCA has cast serious doubt upon the credibility of Distribution's calculation of the cost of a theoretical zero capacity system. The OCA's discovery that NFGD employs a higher cost for a "0" inch main than the actual average cost for one inch and 1 1/2 inch implies an overstatement of the customer component. Likewise, NFGD's regression equation does not conform to actual data points.
>
> In our judgement, enough doubt has been cast upon NFGD's study as to merit its rejection herein. Accordingly, we will adopt the OCA's study for the purpose of this case.

The Commission was clear in that case that it was the manner in which the zero-intercept method was applied that cast doubt upon the validity of the results. There was no mention that the Commission disagreed with the ALJ that there is a customer component to mains. The only issue mentioned was the calculated results of the zero-intercept method employed by NFGD. This is an important distinction from the current case, since Columbia is not calculating the customer component of mains based on a zero intercept method using a theoretical 0 inch main. In contrast, Columbia has calculated its customer component of mains based on the actual cost of its 2” mains pipe, not a theoretical 0” pipe.

In the 1986 *Pa P. U. C. v. Peoples Natural Gas Co.* case, the basis of the Commission's decision was explained on page 22 of the Opinion and Order where the Commission said

> While the size and capacity of Peoples' transmission facilities may have been designed to meet anticipated peak loads, a distribution system would still have to be constructed and maintained if these peak loads did not occur. Clearly, these facilities provide gas service to customers every day of the year. Absent an alternative to the cost of service studies presented by the Company, we prefer the fifty percent demand, fifty percent commodity allocation offered by the OCA.

It is clear the Commission selected the Peak & Average study "absent an alternative to the cost of service studies presented." An average study was not proposed in the *Peoples Natural Gas* case, so the Commission selected the Peak & Average study over the 2 inch minimum system study as the sole study to base the allocation of revenue to the rate classes.

Q. On page 9 of his Direct Testimony, Mr. Cline says "The Commission also reaffirmed that the cost of mains should be allocated on a combination of throughput and demand", citing to *PPL Gas Utilities*, Docket No. R-00061398, Order entered February 8, 2007 where Administrative Law Judge Jones noted that "the Commission has rejected minimum and zero-intercept system methods as inconsistent with causation". Do you have any comments about the use of this case and its relevance to Columbia's current case?

A. Page 70 of the Administrative Law Judge's Recommended Decision states: "Mr. Watkins (OCA witness) posits that Mr. Knecht's method of determining the percentage of costs that should be demand-related and customer related, the zero-intercept method is problematic. The Commission has in the past rejected the zero-intercept and minimum system methods as inconsistent with cost causation." The Administrative Law Judge then cites the *Pa. P.U.C. v National Fuel Gas Distribution Corp.*, 83 Pa. PUC 262 (1994) and *Pa. P.U.C. v National Fuel Gas Distribution Corp.*, 73 Pa. PUC 552 (1990) cases as support.

It is important to note that the Administrative Law Judge emphasized that Mr. Watkins stated "The Commission has in the past rejected the zero-intercept and minimum system methods as inconsistent with cost causation." The Administrative Law Judge stated on page 70 that

> Most compelling is Commission precedent that has rejected minimum and zero-intercept system methods as inconsistent with causation. OSBA does not even attempt to distinguish this proceeding from the case law presented regarding a natural gas distribution company. Further, the OSBA does not reference any Commission order accepting a company's COSS which uses the minimum and zero-intercept method.

Finally, the Administrative Law Judge stated on page 71 "The concept of main costs derived from both distance and capacity factors is persuasive, yet the model and calculations provided present misgivings to implement the concept as proposed. Consequently, the alternative provided by OSBA is substantially uncertain as representative of the costs for use."

It was the statistical basis of the OSBA zero-intercept model as presented and the lack of OSBA citing Commission precedent that caused the judge to reject the OSBA proposal. The *PPL Gas Utilities* case is just another example where the inaccuracy of the zero-intercept model as presented, caused the judge to look at precedent that accepted the Peak & Average study "absent an alternative to the cost of service studies presented." Since Columbia has presented alternatives to the Peak & Average study, the authorities to which Mr. Cline cites as support for his position that the Commission favors Peak & Average are not applicable to the present case.

Q. Witness Mierzwa states that the Company's ACOSS which relies on the assignment of distribution mains to separate pressure groups should be rejected. Do you agree with this statement?

A. No. The primary purpose of assigning distribution mains into separate categories is to develop a mains cost allocation that is more consistent with cost incurrence. Because of the Company's Graphical Information System ("GIS"), the Company has the capability to identify which premises are served off which pipe segments, the operating pressures of those pipe segments, the size of pipe, and the pipe material (ie. steel, plastic). This further refinement allows Columbia to more accurately identify the specific mains being used to serve specific customers and, therefore, more accurately assign mains when determining the revenue responsibility for each rate class.

Q. What ACOS Study is I&E witness Cline using to evaluate proposed revenue in this proceeding?

A. Mr. Cline is using the Company's Peak & Average Study, which includes separation of the operating pressure groups in the determination of the mains allocator.

Q. What was the key reason Mr. Mierzwa gave as to why he recommended rejection of the Company's separation of the operating pressure groups in the determination of the mains allocator?

A. Mr. Mierzwa stated on page 8 of his direct testimony that "CPA's proposed separate assignment and allocation of distribution mains fails to consider the net investment of each distribution mains category." Mr. Mierzwa goes on to explain that the separation of the pressure groups based on gross plant investment does not take into account the age of the pipe. He then states that low pressure pipe is generally older and therefore more depreciated than regulated pressure pipe and that is important because rates are set on net investment, not original cost.

Q. Mr. Mierzwa disagrees with CPA's proposed separate assignment and allocation of distribution mains investment by operating pressure because the allocation uses original cost and not net investment. Does Columbia have any comments on his opinion?

A. Yes. Mr. Mierzwa criticizes CPA's ACOS studies because Columbia matches the allocation of depreciation reserve with the allocation of plant in service to come up with net plant. However, Mr. Mierzwa in his ACOS study does the exact same thing. The difference is that CPA first identifies mains cost by operating pressure on a customer by customer basis using customer and engineering information.

Mr. Mierzwa speculates that because 53% of low pressure system pipe is constructed of steel, and because steel pipe is generally older and therefore more depreciated than plastic pipe, customers served off low pressure should be assigned less net investment than regulated pressure customers.

CPA's ACOS studies, which allocate distribution mains investment by operating pressure and by pipe size, does account for the assignment of steel versus plastic pipe to the rate class based upon customer and engineering information. To the extent Mr. Mierzwa is correct that steel pipe is older, then under CPA's studies, the original cost allocated to the rate classes will be lower to those customers who utilize steel mains than those who utilize plastic mains. Mr. Mierzwa's Peak & Average study does not allocate costs in that manner. In fact, the net plant based on original cost in Mr. Mierzwa's Peak & Average study gives no weight to customers served by a low pressure system or even steel pipe in general.

Q. As support for his conclusion that his Peak & Average Study produces results consistent with those of a Proportional Responsibility method for allocation and, therefore, should be supported by CPA, Witness Mierzwa references Columbia Gas of Massachusetts' ("CMA") most recent base rate case (D. P. U. 18-45). Does this case reference have any relevance to the current CPA case?

A. No. If the purpose of witness Mierzwa referencing the CMA rate case is to somehow infer that the Proportional Responsibility method of allocating costs is a method preferred by all of the Columbia Companies, including CPA, that logic would be incorrect. In Massachusetts, the Department of Public Utilities, and not

CMA, has determined that the Proportional Responsibility method of allocating the cost of service is the required study that must be included in its rate case filings and the rate case filings of all natural gas distribution companies in Massachusetts. Thus, while CMA must use this method, CPA does not endorse this method.

The Proportional Responsibility method also has no relevance in independently verifying Mr. Mierzwa's modified Peak & Average Study as the sole study in which to determine revenue by rate class. The Peak & Average method uses 50% weighting based on throughput and 50% weighting based on design day demand. The Proportional Responsibility method is based on monthly throughput throughout the year with a weighting from lowest usage months toward highest usage months to account for design day usage. It is no wonder that an allocation of mains based on average throughput and design day usage would produce similar results to an allocation of mains based solely on monthly throughput weighted to account for design day usage.

Q. Do you agree with Mr. Mierzwa that the cost of major account representatives should be allocated to the large customer classes 50 percent based on customers and 50 percent based on annual volumes?

A. No. Mr. Mierzwa is selectively identifying an expense that the Company incurs to negotiate flex rate agreements, accommodate billing inquiries, operational needs and marketing of large competitive customers. Residential customers do benefit when Columbia can retain a large customer who has alternative fuel capabilities, because the large customer contributes to the recovery of shared costs. As for billing inquiries, the residential customer has the call center for their billing inquires. If major accounts representatives cost were only assigned to the large customers, it would only be fair to credit the large customers in some way to recognize that they do not use the call center for bill inquiries. The same argument goes for marketing activities. The residential class has specific representatives that are experts in residential marketing that arguably provide no benefit to the large customers. Under Witness Mierzwa's approach, it would only be fair to credit the large customers for this expense. As for operational needs, it is as important to residential customers as large customers when the major account representatives ensure the large accounts manage their usage during peak periods. Because the residential class does benefit from the major account representatives and because, like the major accounts, residential accounts have their own representatives whose costs are equally assigned to the major accounts, it makes no sense to allocate this cost differently than based on number of customers.

Q. Do the results of the studies prepared by witnesses Cline, Mierzwa, and Knecht vary widely from the results of the Company's ACOSS?

A. Yes. For each of the other parties' studies, all of which contain a demand component, the difference in the results is driven primarily by the selection of the remaining component of the allocator—the customer component, annual throughput component or an average of both customer and throughput. Table CEN-1R below illustrates how the use of one or the other can produce results that vary widely. This table also illustrates why revenue allocation to the rate classes should not solely rely on a single study because, as explained above, all studies have shortfalls. However, the Customer/Demand and Peak & Average Studies do show a range of reasonableness.

Table CEN-1R
Unitized Returns at Current Rates

	Total Co	RSS/ RDS	SGS1/DS1	SGS2/DS2	SDS/LGSS	LDS/LGSS	MLDS	Flex
OCA – P&A	1.00	1.34	0.98	1.11	0.85	0.05	16.33	(0.91)
OCA– PR	1.00	1.44	1.14	1.19	0.71	(0.17)	16.33	(0.97)
I&E – P&A	1.00	1.29	1.02	1.19	0.94	0.08	16.75	(0.88)
OSBA – 75% P&A, 25% Cust/Dem	1.00	1.12	1.03	1.46	1.27	0.38	16.75	(0.80)
CPA – P&A	1.00	1.29	1.02	1.19	0.94	0.08	16.75	(0.88)
CPA - Cust/Dem	1.00	0.73	1.06	2.77	3.32	3.32	16.75	(0.11)
CPA – Avg	1.00	0.97	1.04	1.79	1.72	0.83	16.75	(0.67)

Because the residential rate class is the largest and would be expected to be allocated the largest percentage of mains costs, my discussion will focus only on that group. However, this is not meant to imply that the allocation factors suggested for each of the other groups are not meaningful.

As can be seen from this table, the calculated class unitized returns range from a below system average of .73 to a high of 1.29 times the system average return. The mains allocation methods relied upon by the various parties produce a narrower range from a low of 1.12 to a high of 1.44 class return relative to the system average. The highest is from the OCA's Proportional Responsibility Study, which is based on monthly throughput throughout the year with a weighting from lowest usage months toward highest usage months to account for design day usage while ignoring the bifurcation of mains by Columbia into four distinct pressure groups. The lowest is from the Customer/Demand Study while recognizing the gas main each customer is directly tapped from and the upstream mains that feed the gas main into four distinct pressure groups.

The allocation method proposed by the OCA produces returns that fall outside the range of reasonableness that has been produced by Columbia and outside the residential returns based on methods proposed by other parties in this case. Within this range is OSBA's unitized return at 1.12, which is based on a 25% weighting of the Customer/Demand Study and a 75% weighting based on the Peak & Average Study. As discussed earlier, Columbia is not proposing that the Commission specifically adopt its Customer/Demand Study, nor is it recommending the Commission specifically adopt the Peak & Average Study. Instead, these two studies establish a reasonable range within which a mains allocation factor would be expected to lie. As discussed above, to simply choose an allocation method that either fully ignores annual throughput or completely ignores the customer component, creates illogical allocations of mains footage as demonstrated when comparing allocated mains footage to actual footage identified for 9 of Columbia's 10 largest customers. Solely relying on either study would not produce a fair and reasonable allocation of costs. For this reason, Columbia continues to recommend the results of its Average Study as the study that should be relied upon as a revenue allocation guide.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

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COLUMBIA STATEMENT NO. 12-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
SHIRLEY BARDES HASSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

I. Introduction

Q. Please state your name and business address.

A. Shirley Bardes Hasson, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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

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

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your Rebuttal testimony?

A. My Rebuttal testimony will revise the effective cycle billing month of the proposed change to the Weather Normalization Adjustment ("WNA") on tariff pages 162 and 163 and the effective cycle billing month of the newly proposed Revenue Normalization Adjustment ("RNA") on tariff page 144.

Q. What was the original tariff proposal for the WNA?

A. In the Direct Testimony of Witness Bell in Statement No. 3, page 19, lines 1 through 13; my Direct testimony in Statement No. 12, page 10, lines 6 through 11; and pages 162 and 163 of the Proposed Tariff in Exhibit 14, Schedule No. 2, Attachment B, page 32, paragraph (h) and page 33, paragraph (i), the Company is proposing to change the 3% deadband currently applied to the WNA to a 0% deadband effective with the billing of the February 2021 cycle. The current 3% deadband would bill through the January 2021 cycle.

Q. In this Rebuttal testimony, what revisions are you proposing to the effective months for the change to the deadband?

A. I am proposing that Tariff pages 162 and 163 in Exhibit 14, Schedule No. 2, Attachment B, pages 32 and 33 be revised to reflect April 2021 as the effective cycle billing month for the change to a 0% deadband in the WNA calculation, rather than the billing of the February 2021 cycle as originally proposed.

Q. With the revision to the first month of billing the 0% deadband, will the final month of billing the 3% deadband change also?

A. Yes. The final month for cycle billing of the 3% WNA deadband would change from January 2021 to March 2021 in the tariff.

Q. Do you have anything else to add regarding the effective date of billing the 0% deadband?

A. Yes. As Exhibit SBH-1R, I offer two replacement Tariff pages for Exhibit No. 14, Schedule No. 2, Attachment B, pages 32 and 33 of 44, to revise the last cycle for billing of the 3% deadband and the first cycle for billing of the 0% deadband. Those two replacement Tariff pages are Eleventh Revised Page No. 162 and Twenty-fifth Revised Page No. 163 of Tariff Supplement No. 307. The update to Eleventh Revised Page No. 162 appears in Paragraph (h) and a similar revision is evident in paragraph (i) on Twenty-fifth Revised Page No. 163 in Exhibit SBH-1R. In paragraph (h) the references to "January 2021" and "February 2021" in the originally submitted Exhibit No. 14, Schedule No. 2, Attachment B page 32 of 44, have been changed to "March 2021" and "April 2021" respectively. A similar revision to paragraph (i), which appears on page 33 of 44 of Exhibit No.14, Schedule No. 2, Attachment B, page 33 of 44, changes the "January 2021" to "March 2021" as the last cycle billing that includes a deadband of 3%.

Q. What was the original tariff proposal for the initial billing of the RNA?

A. Tariff Page No. 144 in Exhibit No. 14, Schedule 2, Attachment B, reflects October 2021 cycle billing as the originally proposed effective date for the initial RNA using the Peak Period of January 2021 through April 2021 for the calculation.

Q. In this Rebuttal testimony, what revisions to the tariff are you proposing for the initial billing of the RNA?

A. I am proposing that the tariff reflect the RNA change described in Witness Bell's rebuttal testimony, Columbia Statement No. 3-R. Therefore, Exhibit SBH 2R is a replacement to the originally provided Tariff Page No. 144 in Exhibit No. 14, Schedule No. 2, Attachment B, page 28 of 44. The replacement page reflects an initial billing of the RNA for the Off Peak Period, calculated using the April 2021 through September 2021 period and that the RNA begins billing with the April 2022 cycle.

Q. Why does the Company want to delay the implementation of the WNA deadband change and the RNA?

A. In its August 6, 2020 Public Meeting, the Pennsylvania Public Utility Commission ruled that while Columbia's application of rates was suspended until February 4, 2021, the final approved rates will be effective as of January 23, 2021. Columbia and the other parties in this proceeding then agreed to further suspend the Company's application of rates, from February 4, 2021 to February 24, 2021, but keeping the effective date for new rates as January 23, 2021. Therefore, Columbia's Information Technology function will implement programming that will result in an adjustment on each customer's invoice issued after final rates are approved. In order to ensure accurate customer bills during the period of back billing, Columbia is proposing to postpone implementation of the deadband percentage change.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

RIDER WNA – WEATHER NORMALIZATION ADJUSTMENT

A Weather Normalization Adjustment (WNA) shall be applied to bills of Residential customers under Rate Schedules RSS, RDS, and CAP, for the heating season November through May. The WNA shall continue until a final Order is entered in the Company's first rate case filed after May 31, 2020. The WNA will be applied to November through May billing cycles and shall be calculated as follows:

WNBT = BLMT + [(NHDD / AHDD) x (AMT-BLMT)]

WNAT = WNBT – AMT

WNA = WNAT x Distribution Usage Charge

(a) Weather Normalized Billing Therms (WNBT) will be calculated as the Base Load Monthly Therms (BLMT) added to the product of the Normal Heating Degree Days (NHDD) divided by the Actual Heating Degree Days (AHDD) and the Actual Monthly Therms (AMT) less the Base Load Monthly Therms (BLMT).

(b) Base Load Monthly Therms (BLMT) are established for each customer using the customer's actual average daily consumption from the billing system, measured in therms, for the two months with the lowest consumption per billing day for the three billing months of July, August and September. The average baseload per day information will be updated annually. If actual BLMT information is not available for the year, the Company will use the most recently available base load information for the premises. If no history is available, the Company shall use the overall base load average for the residential class reflected in the most recent rate case.

(c) Normal Heating Degree Days (NHDD) shall be updated annually by September 1st using the same methodology established in the Company's most recent Rate Case. NHDD for any given day are based upon the 20 year average for the given day.

(d) Actual Heating Degree Days (AHDD) are the actual experienced heating degree days for the billing cycle. The degree day data is provided by the National Oceanic and Atmospheric Administration (NOAA). Customers will be assigned to weather stations based on their geographic locations.

(e) Actual Monthly Therms (AMT) are measured for each customer and billing cycle.

(f) Actual Monthly Therms (AMT) will be subtracted from the Weather Normalized Billing Therms (WNBT) to compute the Weather Normalized Adjustment Therms (WNAT).

(g) The WNAT is then multiplied by the residential Distribution Usage Charge to compute the WNA amount that will be charged or credited to each residential customer.

(h) A 3% deadband shall be effective through the March 2021 cycle billing. The WNA for a billing cycle will apply only if the AHDD for the billing cycle are lower than 97% or higher than 103% of the NHDD for the billing cycle. A billing adjustment will only occur if the variation of AHDD is lower than 97% or higher than 103% of the NHDD for an individual billing cycle. Beginning with the April 2021 cycle billing, the deadband will be 0%. (C)

(C) Indicates Change

RIDER WNA –WEATHER NORMALIZATION ADJUSTMENT (Continued)

(i) Effective through the March 2021 cycle billing, the WNA factor will be calculated by first adjusting the NHDD for the billing cycle by the deadband percentage of 3%. The deadband percentage is multiplied by the NHDD and then added to NHDD for the billing period when the weather is colder than normal (i.e., AHDD>NHDD) or subtracted from NHDD for the billing period when the weather is warmer than normal (i.e., AHDD<NHDD).

(j) The Company will file weather normalization information with the Commission annually by October 1st.

The Purchased Gas Cost shall be applied to actual (or non-adjusted) sales therms.

RIDER RNA – REVENUE NORMALIZATION ADJUSTMENT (C)

APPLICABILITY

Throughout the territory served under this tariff.

AVAILABILITY

The RNA shall apply to non-CAP residential customers under Rate Schedules RSS and RDS.

DEFINITIONS

Peak Period ("p") is October through March.
Off-Peak Period ("o") is April through September.
RNA is the Revenue Normalization Adjustment for non-CAP residential customers for the applicable period.
BDRB is the Benchmark Distribution Revenue per Bill for non-CAP residential customers for the applicable period.
ADRB 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.

REVENUE NORMALIZATION ADJUSTMENT CALCULATION

The RNA is computed for two separate periods. At the conclusion of the Peak Period, the RNA to be applied to customers' bills beginning with the next Peak Period will be calculated. At the end of the Off-Peak Period, the RNA to be applied to customers' bills beginning with the next Off-Peak Period will be calculated.

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

Off-Peak Period: $$RNAo = \frac{[ANBo \times (BDRBo - ADRBo)]}{FTo}$$

The initial RNA to be billed to customers will be Off-Peak, will begin with the April 2022 cycle billing and will be calculated based upon the six-month period beginning with the April 2021 cycle billing.

BENCHMARK DISTRIBUTION REVENUE PER BILL FOR NON-CAP RESIDENTIAL CUSTOMERS

Benchmark Distribution Revenue per Non-CAP Residential Bill shall be computed as the Fully Projected Future Test Year Base Revenue divided by the number of residential bills for the applicable six-month period. New BDRB levels for the Peak and Off-Peak Periods will be established with each rate case filing.

(C) Indicates Change

COLUMBIA STATEMENT NO. 13-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

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 comments related to Universal Service Programs provided by Mr. Roger Colton of the Office of Consumer Advocate ("OCA"), Mr. Mitchell Miller of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), and Ms. Susan Moore of Community Action Association of Pennsylvania ("CAAP")

Q. What issues will you address related to Mr. Colton's testimony?

A. First, I will respond to Mr. Colton's assertion the Company's CAP collection policies are inadequate and do not comply with the Pennsylvania Public Utility Commission's ("Commission") CAP Policy Statement.

Q. Do you agree with Mr. Colton's assertion?

A. No. Mr. Colton provides data in RDC-1 labeled as full, on time payments and compares this to the number of bills rendered. This full, on time payment data corresponds to data provided in response to the annual Universal Service

Reporting Requirements (USRR). The definition for this data point, as the Company understands, reflects the receipt of all payments for a customer excluding LIHEAP and Hardship Funds. However, it is important to recognize, LIHEAP funds supplement past, current and future customer payments. As a result, a customer may be current on their CAP bill but have not paid twelve, on time and in full payments in a year due to LIHEAP grant credits. The LIHEAP grant credits are not included in the full, on time payment data referenced by Mr. Colton and therefore, any assumption regarding collections based on this data is inaccurate.

Q. Do the Company's CAP collection policies comply with the PUC's CAP Policy Statement?

A. Yes. The Company complies with its Universal Service and Energy Conservation Plan ("USECP"), which states:

> *Columbia will issue a termination notice no sooner than 10 days after a customer fails to pay two missed CAP budget payments by the due date.*
>
> *If a CAP customer does not make up all missed CAP payments within 10 days of the date of the termination notice, Columbia will attempt to terminate service for non-payment of the CAP budget bill. Columbia, in its sole discretion, may delay termination in the event of extenuating circumstances.*

The Company's USECP is consistent with the CAP collection activity portion of the revised CAP Policy Statement, as amended at Docket No. M-2019-3012599, in that it provides that "a utility should initiate collection activity for CAP accounts after no more than two payments in arrears." 52 Pa. Code § 69.265.

Q. If the Company policies are following recommended and approved guidelines, why are CAP customers not paying a higher percentage of their expected payments or being terminated?

A. As previously explained, the referenced data is missing crucial LIHEAP funds which negates the ability to link full, on time payments with CAP customers that are current on their pay plan. Therefore, more customers are current than are represented by the full on time payments data.

In addition, there are other reasons why a CAP customer's service may not be terminated for nonpayment. CAP terminations fall under the same regulations as all other residential customers. The Company does not pursue termination of services when a dispute is filed with the Commission prior to termination or a customer identifies the service is critical to their health via a medical certificate. In addition, the Company does not issue termination notices to CAP customers during the winter moratorium from December 1st through March 31st. This is demonstrated by the zero CAP disconnects shown for 5 of the months on Mr. Colton's Table 1.

Q. How does the Company's CAP default rate compare to other PA utilities CAP default rate?

A. According to the 2018 USRR, the Company's default rates are consistently the lowest compared to other Pennsylvania gas and electric utilities.

Q. How does the Company's percentage of CAP bills paid compare to other Pennsylvania utilities' percentage of CAP bills paid?

A. According to the 2018 USRR, the Company's percentage of CAP bills paid in 2018 was the 3rd highest of all PA gas utilities. As defined in the 2018 USRR report, the percentage of CAP bills paid by CAP customers is calculated by dividing the total annual CAP payments by the total annual CAP amount billed. The higher the percent of CAP bills paid by the customer, the less the public utility may have to recover in uncollectibles. CAP customer payments may include energy assistance grants (e.g., LIHEAP, Hardship Fund, etc.).

Q. Do you agree with Mr. Colton's recommendation that Columbia submit the question of how customer payments on CAP bills can be pursued through a reasonable collections process to its Universal Service Advisory Council?

A. No, for the reasons that I have explained, I do not believe that Mr. Colton's recommendation is necessary.

Q. What additional issues would you like to address related to Mr. Colton's testimony?

A. I will address Mr. Colton's recommendations regarding the Company's outreach strategy and communication plan, and respond to his concerns regarding the Company's outreach to low income customers..

Q. Please provide Mr. Colton recommendations regarding the Company's outreach to low income customers.

A. Mr. Colton recommends four specific outreach mechanism, all of which Columbia already utilizes in its customer outreach strategy. The first recommendation is to offer CAP when establishing a payment arrangement. The Company already offers CAP to all level 1[1] customers in arrears, so this mechanism is currently in practice. The second recommendation is to offer CAP prior to involuntary service disconnection. The Company's current ten day notice of termination includes information including income charts and a request for customers to contact the company to determine what programs and payment options are available to them. When a customer calls in to inquire about stopping a termination, all level 1 customers are provided information on CAP and pre- screened and referred to CAP if the customer agrees. This recommendation is currently in practice. The third recommendation is to offer CAP when a disconnected customer calls requesting to be reconnected. When a customer calls requesting reconnection, financial information is requested and all level one customers are referred to CAP. This recommendation is already in practice. And the fourth recommendation is to offer

[1] Level 1 refers to all customers at or below 150% of the Federal Income Poverty Guidelines.

CAP when contacting a customer through the cold weather survey. When a customer on the cold weather survey calls to connect service, financial information about the household is requested. All customers identifying themselves as level 1 are referred to CAP. This recommendation is already in practice.

Q. Does Mr. Colton make any other recommendations regarding the Company's outreach strategy or efforts? If so, explain.

A. Yes. Mr. Colton also recommends that Columbia incorporate four "principles" into the "Outreach Strategy and Communications Plan" that is currently under development by the Company. The four principles are: (1) use the community as a means of identifying and engaging the hard to reach population; (2) focus on relationship building as opposed to relying on staff contacts; (3) go to the community rather than making the community come to you; and (4) rather than relying primarily on Company communications, rely on trusted messengers from within the community.

Q. Is the Company working on an outreach strategy and communication plan?

A. Yes. The Company began the process of developing an outreach strategy in August 2019 with an internal meeting of various stakeholders. From this meeting, an outline of targeted groups and strategies was developed. In April 2020, a detailed review of the plan was shared with the Company's Universal Service Advisory

Council. The Company revised the plan further based on feedback from the Council.

Q. What is your position regarding Mr. Colton's recommendations to the Company's outreach strategy and communications plan?

A. Outreach plans should be a living document that evolve over time with experience, results of activities and the ever-changing dynamics of the targeted groups. Therefore, Columbia seeks the input from targeted outside entities to improve or expand outreach opportunities. For example, as noted earlier, the Company has sought the feedback of its Universal Service Advisory Council in the development of its customer outreach plan. However, Mr. Colton seems to be suggesting that the Company does not engage in any program promotion outside of our call center, which is inaccurate. In fact, quite the opposite is true. The Company has utilized a variety of venues and methods to reach out to customers such as Be Utility Wise Events, Senior and Legislative events, Community meetings, CAP screening agencies, updated web sites, targeted mail solicitations, social media paid ads, ads on Company sites, and radio and Senior Newspaper ads.

Over the 28 years that I have been promoting low-income programs, the Company has placed ads on buses, billboards, newspapers, television, radio and social media. The Company has taken applications in worship sites, unemployment offices, banks, stores, Community Action agencies, senior centers, Salvation Army offices, and in customer homes when necessary. The Company has partnered with various community resources including Housing Authorities, Veteran's groups, career training centers, medical clinics, Department of Human Services, and other local community based agencies. Each year the Company develops a strategy for outreach that includes an advertising component, at least one company sponsored community engagement opportunity, and identifies a new audience to specifically target such as the elderly, veterans or the working poor. In addition, the Company participates in fifteen to twenty legislative and/or senior events and three Be Utility Wise events to promote programs to individuals, community advocates and caseworkers. Many of these outreach strategies will be included in the Company's overall plan, but others have been deemed unsuccessful and not as efficient as other methods. The experiences of both Company personnel and community advisors will facilitate the development and implementation of a solid plan to reach out to all potential customers in need.

Q. Does Mr. Colton provide an explanation as to why he is critical of the Company's outreach strategy?

A. Yes. Per Mr. Colton's testimony on page 19, Mr. Colton has relied on the Company's response to a data request, specifically OCA 4-041[2], for his understanding of how the Company identifies its low income customers. By way of background, each utility is required to provide a "confirmed" low income count on the USRR. The

[2] Mr. Colton incorrectly identifies OCA 4-041, however, the Company's response to OCA 4-042 responds to how the Company identifies its low income customers.

Company reports the number of "confirmed" low income as the number of customers who have either self-declared or verified their income as low income. Therefore, when responding to the question "provide a detailed description of the definition of low income and the means by which a customer is identified as low income" at OCA-4-042, the Company provided the definition used when reporting the confirmed low-income count on the USRR. By no means should this report definition suggest that the Company is not actively engaged in outreach activities within the community.

Q. Do you have any other issues that you would like to address related to Mr. Colton's testimony?

A. Yes. I will address Mr. Colton's assertion that the Company does not protect customers from being adversely impacted by an increase in the fixed monthly customer charge.

Q. Do you agree with Mr. Colton's assertion that the Company does not protect CAP customers from being adversely affected by the increase in the fixed monthly customer charge in part because 61% of customers are on the Percent of Bill payment plan option?

A. No. I do not. As Company Witness Bell points out in her rebuttal testimony, even those on the Percent of Budget, which is the title of this option in the Company's USECP plan, will realize only half of the impact of any rate increase. Further, although the CAP administrators select an affordable CAP option at the time of the customer's enrollment into CAP, there are opportunities to adjust a CAP customer's payment if it becomes unaffordable. For example, the Company conducts a review of CAP accounts on a bi-annual basis to determine if a payment plan needs to be lowered. In addition, any time a customer contacts the Company to state they cannot afford their CAP payment, a lower option is offered if available.

The Percent of Budget payment plan option is often a lower option than the Percent of Income option. Responding to CAUSE-PA 1-10, which is attached as Exhibit DAD-1R, the Company provided energy burden levels by payment option. Those customers on Percent of Budget currently pay between 3.44% and 5.24% of their income. With the rate increase, the average customer currently on the CAP Percent of Budget plan would pay 5.23% of their income. The Commission's amended CAP Policy Statement suggest 4% – 6% energy burden is affordable.

Q. Do you have any additional issues you would like to address related to Mr. Colton's testimony?

A. No, I do not. However, other Company witnesses will be providing further responses to Mr. Colton's testimony. Company Witness Tubbs will address Mr. Colton's recommendation that Universal Service costs be allocated to all rate classes. In addition, Witness Tubbs will be addressing Mr. Colton's statement regarding CPA's collections performance. Company Witness Bell will address Mr. Colton's assertion that an increase in customer charge will harm low income customers.

Q. What issues will you address related to Mr. Miller's testimony?

A. First I would like to address Mr. Miller's statement that the Company's current Universal Service programs are inadequate. The Company has open enrollment of its CAP program and refers all level 1 customers to the program. The Company's CAP asked-to-pay amount, as reported in the 2018 USRR, is the lowest average payment of all Pennsylvania utilities. Its Hardship Fund currently has over $700,000 remaining in funds and will be replenished in October with more than $600,000 in additional assistance. The LIURP program is funded at a higher level than most Pennsylvania gas utilities. The Company undertakes extensive promotion of all its programs, including the federal LIHEAP program, year round. Customers that need assistance and are willing to apply will receive enough assistance to afford and maintain their gas bill.

Q. Please address Mr. Miller's recommendation that the Company should improve its CAP participation rate and design a plan to reach 50% CAP enrollment rate by 2025. Do you agree with Mr. Miller's assertion that the existing outreach and enrollment levels are too low?

A. No, I do not. The Company does extensive outreach to low income customers as outlined previously in this testimony. The Company's call scripting states CAP as the best option for low income customers. Therefore, all identified low income customers who need assistance with their gas bill are offered CAP. Confirmed low income includes customers who self-declare their income. In reality, under traditional CAP guidelines, which requires income verification, it is not uncommon for a customer to report their income but refuse CAP participation once they are required to provide income verification. The self-declared income provided by the customer remains "confirmed" low income even though the customer refused to provide supporting documentation. In addition, the last income recorded is considered regardless of how much time has passed since the income was provided.

Q. **Do you agree with Mr. Miller that a steady rate of enrollment over the last decade signals a lack of outreach and enrollment?**

A. No, I do not agree that a steady rate of enrollment over the last decade is a CAP deficiency. The Company's CAP has been in existence for 28 years. A steady enrollment is indicative of a mature program that is assisting those newly in need while maintaining assistance for the vast majority of eligible customers that have already applied.

Q. **Mr. Miller notes "Almost two months into the statewide shutdown and unemployment crisis, Columbia's CAP participation rate has remained relatively unaffected." Do you feel this is a reflection of the Company's lack of effort to promote the program?**

A. Absolutely not. The Company has expanded communications during the pandemic with additional emails and letters to customers as well as paid ads on social media to encourage customers to contact the Company to find out what assistance is available. During the past five months, the Company has sent an e-mail, a letter, and attempted two phone calls to customers with arrears to explain programs and resources available to provide assistance. In addition, multiple posts on its social media outlets have been added regarding programs. Finally, the Company paid for four rotating ads on social media to promote the LIHEAP Recovery CRISIS and other available programs. In addition, customers identified as eligible for the LIHEAP recovery CRISIS program were called to attempt an application on their behalf. Further, out of concern with customers lacking access to income documents, the Company relaxed the guideline for CAP to temporarily waive the income documentation requirement. Once the Commission's emergency orders are lifted, those customers who have been accepted into CAP without any income documentation will be required to provide documentation. I am also advised by our CAP and Hardship Fund administrator that all of their utility programs are experiencing a reduced participation rate. In addition, the Department of Human Services provided an update at the last LIHEAP Advisory Council meeting on the LIHEAP Recovery CRISIS program. As of July 8, 2020, less than half of the funding was distributed. This may be related to the Commission's Emergency Order at Docket No. M-2020-3019244 preventing terminations, as there is not an imminent need for customers to address their accruing arrearages.

Q. Should metrics be developed based on the percentage of enrolled customers in the program compared to the number of confirmed low income customers reported?

A. No, for several reasons. First, the confirmed count is not a true reflection of customers eligible for CAP because not all self-declared low income customers actually qualify for CAP based on documented income. Second, not all low-income customers need or want to participate in CAP, and participation in CAP is entirely voluntary. Many customers are able to afford their bill with the help of LIHEAP and CAP is not necessary. Some combine LIHEAP and a Hardship Fund grant to be able to cover their annual gas bill. Some low income customers usage is lower than average and can afford their bill without any assistance. As such, any metric should be based on activities to work toward the result of increased CAP participation such as outreach, not the final result of enrollment. Actual enrollment is outside the Company's control, because it is ultimately the customer's decision whether to enroll in CAP. Finally, the Company already strives to promote CAP enrollment through every day customer service interaction, social media posts, community meetings and information, and updated information on the Company's website. Therefore, the Company does not support a metric around CAP participation but will continue to seek input from its advisory group on appropriate outreach avenues.

Q. How does the Company's CAP participation rate compare to other Pennsylvania Gas utilities CAP participation rates?

A. Columbia's CAP participation rate is better than most other Pennsylvania Gas utilities. In 2017 and 2018, Columbia's participation rate was the second highest according to the USRR. Furthermore, only one gas utility has reached 50% of confirmed low income participation rate in the last three years and, unlike Columbia, that utility only counts confirmed low income if there is documented income on file. Customers claiming to be level one are not counted as confirmed low income unless documentation is received. Naturally, a higher percentage of low income is attainable under those circumstances. Under Columbia's current definition of confirmed low income, a 50% participation rate is unrealistic for the reasons explained above. The Company is already outperforming other gas utilities in Pennsylvania with respect to CAP participation.

Q. Are there any additional issues you would like to address regarding Mr. Miller's testimony?

A. Yes. I will discuss Mr. Miller's recommendation to reduce the CAP percent of income payment plan option.

Q. Do you agree with Mr. Miller's recommendation?

A. No. Columbia's USECP, including the CAP percent of income payment plan, was approved by the Commission in January 2020. During that proceeding, interested parties including CAUSE-PA, had the ability to comment and influence the outcome of that proceeding. The Company is currently developing and implementing costly programming changes to comply with the Commission's final order. Implementing changes to the design of a program twice within a two-year period is inefficient and creates confusion for participating customers and company representatives who must explain the constant changes. It also makes program evaluation difficult when there is no consistency year over year.

Q. Do you agree that it is necessary to reduce the CAP energy burden to four and six percent?

A. No. Columbia's current removal rate from CAP for failure to pay is less than 5%. Of the removals for non-payment in 2019, 25% were on Percent of Income payment plan, 12% were on minimum payment plan and the remaining 63% were on the Percent of Budget and Average of Payment options. Of the customers on the percent of income plan, 4% were removed for non-payment and 3.6% of the customers were on the minimum payment plan. This data is relevant since the customers on minimum payment pay a higher energy burden than the percent of income plan customers leading one to believe that energy burden is not the only factor that influences non-payment.

In addition, the CAP design does not account for the fact that LIHEAP is also available to further reduce CAP required payments. The average LIHEAP cash grant during the 2018/2019 program year for CAP customers on the percent of income payment plan was $280.00. The average monthly payment is $56.00 or

$672 annually. If a customer receives the average LIHEAP grant of $280, their monthly CAP payment drops to $32.00. The average monthly income for this group is $765. With a LIHEAP grant, their energy burden falls to 4.18% for all customers. This does not include a minimum CRISIS grant of $300 that can be used in the event they fall behind. The Commission requires utilities to encourage LIHEAP participation and the Company agrees CAP customers should apply for LIHEAP on an annual basis. Witness Miller correctly points out that not all CAP customers receive LIHEAP; however, all CAP customers are eligible for LIHEAP. It is logical to conclude if a customer needs additional assistance, and it is available, they would apply. This suggests some customers can afford their current CAP asked to pay amount and choose to not apply for LIHEAP. Further reducing the energy burden so that LIHEAP is no longer necessary to satisfy the subsidized bill is poor program design. This issue was analyzed in detail as part of the PUC's Energy Burden Study. The Study concluded LIHEAP had a significant impact in reducing the energy burden for CAP customers. The gas customer's energy burdens were decreased between one and six percentage points depending on their poverty level. However, on a statewide level, the customers less than 100% of poverty were still above the CAP policy statement guidelines even after receipt of a LIHEAP grant. With Columbia's asked to pay amount already the lowest in the state, the receipt of a LIHEAP grant does bring the majority of customers below the new 4%

and 6% guidelines. All available resources should be leveraged and encouraged as the CAP was originally designed.

Q. What other factors should be evaluated when considering the reduction of the percent of income plan?

A. It is appropriate and necessary to consider the financial impact of the recommended reduction to non-CAP ratepayers. As presented in response to CAUSE-PA 1-024, the cost to reduce the Percent of Income Payment Plan option to 4% for those at 50% of poverty or less and 6% for those at 51 – 150% would be more than $1,000,000 per year. This cost would result in roughly a 5% annual increase to non-CAP customers. Mr. Miller asserts the cost to be only $2.67 per year per customer; however, this number is based on current enrollment levels and current gas costs. As either of these factors rise, the cost to subsidize the CAP program grows significantly. In 2009, shortfall cost totaled more than $23 million. In comparison in 2019 with a similar number of customers enrolled but lower gas costs, the shortfall was $18 million. It is important to recognize, non- CAP customers include low income customers who do not participate in CAP and those slightly over the CAP income guidelines. To make this costly change, when only 4% of existing percentage of income customers are removed for not paying their CAP payment and a LIHEAP grant would reduce the average energy burden to 4.18% is not good public policy.

Q. Are there any additional issues you would like to address regarding Mr. Miller's testimony?

A. Yes. I would like to address Mr. Miller's recommendation to raise the Health and Safety Pilot by $600,000 and extend the pilot until 2023.

Q. Do you agree with Mr. Miller's recommendation?

A. The Company does not support increasing the Health & Safety Pilot by $600,000 or from the current budget of $200,000 to $800,000. The pilot did not receive approval until January 2020. In March 2020, all in-home activity for LIURP was suspended due to the ongoing COVID-19 Pandemic. The earliest results measuring the costs and benefits of the Health & Safety Pilot will not be available until late 2021. The Company is working through implementation issues and needs time to build gradually, adapt to lessons learned and respond to new opportunities that can be gained by implementing a smaller pilot. The Company would not be opposed to extending the pilot until 2023 as that would allow for results from a full two years of implementation.

Q. Mr. Miller states that over 60% of CAP customers will be impacted by the rate increase. Is that accurate?

A. Based on current enrollment trends, the roughly 60% of CAP customers who are on the Percent of Budget plan would be impacted by the rate increase, but only to a degree. This is because the Percent of Budget plan is 50% of the CAP customer's budget. Any increase to rates would increase a customer's budget, and in the case of CAP customers on the Percent of Budget plan, the increase in their payment would be approximately half of their increased budget amount. However, as noted in this testimony above, the negative impacts to CAP customers are mitigated by on demand and regular reviews.

Q. Does that conclude your testimony related to Mr. Miller's testimony?

A. Yes.

Q. What issues will you address related to Ms. Moore's testimony?

A. I will address Ms. Moore's recommendation to increase the LIURP annual budget by $420,000.

Q. Do you agree with Ms. Moore's recommendation to increase the LIURP annual budget?

A. No. The 2018 USRR lists the Company's budget as the second highest of all gas utilities behind Philadelphia Gas Works. In a prior rate case, Columbia agreed to an increase in LIURP spending resulting in an annual budget of $4,875,000. This increase most likely maintains Columbia's USRR ranking of the second highest LIURP budget among all gas utilities and the highest in Western Pennsylvania. Evaluation of program spending since 2018 indicates Company contractors have not spent their entire budget which has resulted in carrying over funds to the following year. Furthermore, the Company utilizes county weatherization providers throughout our service territory. These providers often find it difficult to spend both their annual county DOE and Company allotment. Increasing the budget will only exacerbate this problem.

Q. Is there a second issue related to Ms. Moore's testimony that you would like to address?

A. I would like to address Ms. Moore's recommendation that the Company partner with CAAP member agencies for the administration and implementation of the LIURP programs.

Q. Does the Company partner with CAAP member agencies for the administration and implementation of the LIURP programs?

A. Yes. The Commission's Bureau of Consumer Services encourages utilities to partner with the county weatherization programs to improve efficiencies and leverage resources. To that end, Columbia contracts with many of the county providers. Some of these providers are also CAAP members. In addition many of the CAAP members are CAP and Hardship Fund screening agencies that take applications for Columbia customers. However, Columbia should not be directed to partner with specific CAAP members. Many factors impact the Company's decision of who to partner with, including the service territory of the contractor, the ability to satisfy the projected need in that service territory, whether a contractor does work with electric utilities and other county providers, the historical savings realized by a contractor as well as current contract terms and performance by existing contractors. In other words, although Columbia seeks to partner with CAAP members, its decision ultimately comes down to what entity best fulfills the specific need for the project/s. With that said, the Company does consider the current list of CAAP member agencies prior to determining who the appropriate partner is for the existing need.

Q. Are there any other additional issues related to Ms. Moore's testimony you would like to address?

A. Yes. I would like to address Ms. Moore's recommendation to increase the Hardship Fund from $650,000 to $800,000 annually with the Company being directed to contribute the difference after customer contributions.

Q. Do you agree with raising the Hardship Fund to $800,000 annually?

A. No. The Company continues to find new ways to promote customer contributions through Company sponsored events and fundraising activities. In addition, the Company supports Dollar Energy Fund fundraising activities which increases customer contributions. The Company also promotes donations through bill inserts and social media messaging. At this time, the Company's shareholder match is more than all of the funds raised by Columbia customers through these activities. Even with this gap between shareholder funds and funds raised, the Company has a current surplus of more than $700,000. Any remaining funds when the program closes in mid-September will be carried over to the new program year, which begins October 1st. The Company also has in place a Commission-approved mechanism that enables the Company to use Pipeline

Penalty Credits to fund its Hardship Fund, up to a maximum balance of $750,000. This mechanism was approved by the Commission in 2018 at Docket No. P-2018-3000160. The Commission's Order is attached hereto as Exhibit DAD-2R. I have been advised by legal counsel that if the Commission were to direct a "contribution" of additional shareholder dollars, the Company would have a right to seek full recoveries of those dollars.

Q. How does the Company shareholder match compare to other PA gas utilities?

A. The Company's shareholder match at $150,000 annually is the third highest donation of all Pennsylvania natural gas utilities.

Q. Does this complete your Rebuttal Testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA) – Set 1

Question No. CAUSE-PA 1-024:

What are Columbia's projected CAP costs for 2020 and 2021, assuming Columbia adopted the revised energy burdens in the Commission's recently amended CAP Policy Statement as of January 1, 2020?

Response:

The Company's response includes the following assumptions based on the referenced CAP policy statement:

a. Columbia adopted the revised energy burdens of 4% for customers at or below 50% FPL and 6% for customers between 51 and 150% FPL
b. The minimum payment of $25 plus CAP plus fee which is currently $2.00 would remain
c. Arrearage retirement continues at the same pace
d. All customers currently below 4% and 6% would continue to pay their current asked to pay amount and would not move to a percent of Income option
e. No dramatic increase in participation rates

The Company would project an increase to shortfall (cap credits) of $1,019,172 annually. The Company projects that all other costs such as administrative fees and arrearage retirement costs would not change significantly. The shortfall increase equates to roughly 5% increase annually for CAP upon adoption. The Company is not projecting an increase to CAP costs year over year, however weather and gas prices are unpredictable and can have a large impact on CAP costs, specifically shortfall costs.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2020-3018835

Data Requests

Coalition for Affordable Utility Services and Energy Efficiency
in Pennsylvania (CAUSE-PA) – Set 1

Question No. CAUSE-PA 1-010:

For calendar years 2017, 2018, and 2019, 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 chart below provides the average energy burden of CAP customers including co pays and CAP plus.

		2017	2018	2019
% of Income	**1 to 50**	6.78%	7.40%	7.64%
	51 to 100	7.07%	7.38%	7.40%
	101 to 150	7.86%	7.99%	8.02%
Avg of Payments	**1 to 50**	4.76%	5.05%	5.34%
	51 to 100	4.15%	4.22%	4.20%
	101 to 150	3.97%	3.18%	2.92%
% of Bill	**1 to 50**	4.15%	4.42%	5.24%
	51 to 100	4.38%	4.56%	5.02%
	101 to 150	4.47%	3.56%	3.44%

**PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265**

Public Meeting held June 14, 2018

Commissioners Present:

Gladys M. Brown, Chairman
Andrew G. Place, Vice Chairman
Norman J. Kennard
David W. Sweet
John F. Coleman, Jr.

Petition of Columbia Gas of Pennsylvania Inc. For Approval to Use Penalty Credit and Refund Proceeds for Its Residential Hardship Fund

Docket Number:
P-2018-3000160

ORDER

BY THE COMMISSION:

On February 28, 2018, Columbia Gas of Pennsylvania, Inc. (Columbia) filed the above-captioned Petition seeking approval to use federal pipeline penalty credit and refund proceeds to support its residential Hardship Fund (Fund). Columbia additionally proposes in its Petition to flow through the residential portion of the credit and proceeds to residential customers through Columbia's Purchased Gas Cost (PGC) rates if the balance of the Fund exceeds $750,000, and flow through the non-residential portion to non-residential customers through PGC rates. The unopposed Petition was filed pursuant to 52 Pa. Code § 5.41.

Columbia's Fund assists those who are at 0-200% of the Federal Poverty Level and are payment-troubled residential customers. The Fund is supported by equal contributions from shareholder money and customer donations. It is administered by the

Dollar Energy Fund. According to its Petition, Columbia raises around $125,000 to $150,000 annually in customer contributions, which are matched by the Company, resulting in approximately $300,000 raised each year for the Fund. Columbia stated that this amount is not sufficient to support its low-income customers. If it were not granted penalty credit and refund proceeds, Columbia's Fund would run out of money before the end of the 2021-2022 program year.

In the past, Columbia received penalty credit and refund proceeds through February 28, 2018, that have allowed the Fund to be fully funded until the 2020-2021 program year. Additionally, the 2016 Joint Petition for Settlement[1] ("2016 Settlement") preceding this Petition allowed for the use of the residential portion of federal pipeline penalty credits and refunds to finance the Hardship Fund. It required Columbia to file a report with any petition to extend the application of credits and refunds to the Fund. Columbia has attached the report in its Petition as Exhibit A. Columbia has demonstrated, as per the 2016 Settlement, that it has taken efforts to try to expand its Hardship Fund through outreach and programs with other regional public utilities and community agencies.

FERC-regulated pipelines assess penalties to shippers that have not followed pipeline requirements. FERC normally requires pipelines to distribute the penalties collected and refund proceeds to non-offending shippers. The Petition claims that during the previous four years, Columbia has received $1,922,235.29 through penalty credits and refund proceeds from its seven interstate pipelines. Approximately $750,000 of that total has gone towards the Fund in the past two program years. There is a total of $1,172,235.29 remaining in penalty credits and refund proceeds to use in 2019, 2020, and 2021. That amount currently exceeds the proposed $750,000 limit, and Columbia has

[1] *See* Joint Petition for Settlement for *Pennsylvania Public Utility Commission et al. v. Columbia Gas of PA, Inc.,* Docket No. R-2016-2529660 (September 2, 2016).

proposed that any credits or refunds received flow through in PGC rates to both residential and non-residential customers through 2019.

If Columbia's petition is not granted and all of the penalty credits flow through the PGC rates, there would be little impact on residential customers' bills. For example, the total amount of penalty credits and refund proceeds that Columbia had received from 2014 to 2017 would have resulted in a $4.94 credit per residential customer for that period. This means that each residential customer would only receive about $0.10 of credit on their bill every month. Columbia argues that these penalty credits and refund proceeds are better served to support the Hardship Fund to help those customers who are unable to afford to pay their bill.

Columbia has noted that the Commission recommended a full approval of the 2016 Settlement without modification.[2] Therefore, it is in the public interest to approve funding to support Columbia's Fund while Columbia continues to seek other sources of funding.

Columbia served a copy of the Petition to the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate. The Office of Consumer Advocate filed an answer on March 20, 2018, supporting Columbia's continued use of penalty credits and refunds to fund its Hardship fund, provided Columbia continues to implement ideas and programs from voluntary

[2] *See* Petition of Columbia Gas of Pennsylvania, Inc. for Leave to Withdraw Pleading, *Petition of Columbia Gas of Pennsylvania, Inc for approval to use penalty credit proceeds to fund Residential Hardship Fund and provide credits to Non-Residential PGC Customers,* Docket No. P-2015-2465533 (Petition Filed December 29, 2016).

sources. In the past, the Office of Consumer Advocate has supported Columbia's efforts to use penalty credit proceeds to fund its Fund.[3]

Upon full consideration of all matters of record, we find that approval of this Petition is necessary and proper for the service, accommodation, and convenience of the public. For these reasons, we conclude that approval of the Petition is in the public interest; **THEREFORE,**

IT IS ORDERED:

1. That the petition of Columbia Gas of Pennsylvania, Inc., filed February 28, 2018, is hereby approved.

2. That the proceedings at Docket No. P-2018-3000160 be marked closed.

BY THE COMMISSION

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: June 14, 2018

ORDER ENTERED: June 14, 2018

[3] *See* OCA's Answer to Petition, *Petition of Columbia Gas of Pennsylvania, Inc for approval to use penalty credit proceeds to fund Residential Hardship Fund and provide credits to Non-Residential PGC Customers,* Docket No. P-2015-2465533 (Answer Filed February 23, 2015).

COLUMBIA STATEMENT NO. 13-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

SURREBUTTAL TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

September 16, 2020

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, I have submitted both direct and rebuttal testimony in this proceeding addressing issues relating to the Company's customer programs.

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to the rebuttal testimony served in this proceeding by James Crist, witness for The Pennsylvania State University. Specifically, I will respond to Mr. Crist's suggestion that there should be a thorough review of the Company's universal service programs to determine "cuts and limits" to the programs. (See PSU Statement 1-R, p. 26, lines 9 through 12).

Q. Do you agree with Mr. Crist's suggestion that a thorough review of the universal service programs is necessary or appropriate?

A. I do agree that it is both necessary and appropriate for the Company's universal service programs and their corresponding costs to be routinely reviewed. With that said, the Commission's Bureau of Consumer Services ("BCS") has a process established for such reviews, and Columbia's universal service programs were reviewed in 2019. Every three to five years, natural gas and electric distribution companies are required to submit a new Universal Service and Energy and Conservation Plan (“USECP”) to the Commission for approval. The submitted USECP includes the company’s universal service program components and budgets, and upon submitting the USECP, it undergoes a review by BCS and other interested parties. As part of this review, interested stakeholders are provided the opportunity to review the USECP, ask questions regarding the program components and budgets, and submit comments to the Commission regarding the USECP.

Q. When was Columbia’s universal service programs last reviewed by the Commission?

A. Columbia’s current USECP was submitted to the Commission for review in February 2018 and docketed as M-2018-2645401. At the beginning of the review process, BCS held a meeting in with interested parties. Subsequently, Columbia responded to data requests from the BCS and interested parties. In March 2019, the Company received a tentative order from the Commission, to which the Company and other interested parties submitted comments. The Commission issued another order in August 2019, which required that the Company revise certain components of its universal service programs. The USECP was ultimately approved by the Commission in January 2020. Thus, the Company’s universal service programs were reviewed and approved by the Commission within the past year, and another review is not warranted or necessary at this time.

Q. Are there any other opportunities for the Company's Universal Services programs to be reviewed?

A. Yes. The Commission requires an evaluation be conducted by a third party every six years. Columbia's most recent evaluation was filed with the Commission on September 1, 2017. The evaluation was conducted over a period of six months with a thorough review of data and processes.

Q. Does this complete your Prepared Surrebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 14-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

REBUTTAL TESTIMONY OF
ROBERT M. KITCHELL
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

I. Introduction

Q. Please state your name and business address.

A. Robert M. Kitchell, 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 Vice President of Construction Services for Columbia and Columbia Gas of Maryland, Inc.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to several issues raised by I&E witness Lassine Niambele in his direct testimony. I will also respond to OCA witness David Effron's adjustment for costs associated with Columbia's 2021 capital program and the Company's proposed safety initiatives.

First, I will address Columbia's pipeline replacement program. In that same section I will respond to witness Effron's position regarding Columbia's budgeted capital spend. Then, I will respond to witness Niambele's arguments regarding both pipeline replacement costs and restoration costs.

II. Columbia's Pipeline Replacement Program

Q. Please provide an overview of Columbia's current pipeline replacement program.

A. The Company believes that the accelerated replacement of its first generation system (primarily cast iron, wrought iron and bare steel) is not only prudent, but is an obligation under federal Distribution and Integrity Management Program ("DIMP") requirements. I would note that Columbia's implementation of accelerated replacement of first generation pipeline facilities pre-dated DIMP requirements.

Q. Can you describe Columbia's current status and projected completion of cast iron replacement?

A. As of January 1, 2020, Columbia has 45,294 feet of cast iron remaining in its distribution system. Columbia fully anticipates that it will, and is currently on track to, eliminate all known cast iron by the end of 2022.

Q. In his direct testimony, witness Niambele states that "Columbia's system miles as stated in the Department of Transportation Annual Report shows that the Company only replaced 4.7 percent of the at-risk system for the last five years." Do you agree with witness Niambele?

A. No. First, Part B of the DOT report for 2015 referenced in witness Niambele's testimony shows the miles of main by material type in Columbia's system at the end of 2015 and the 2019 DOT report show the miles of main at the end of 2019. Therefore, the data reflects the pipelines replaced in 2016, 2017, 2018 and 2019 which is a 4-year period and not 5 years, as stated in witness Niambele's testimony.

Second, we do agree that the 2015 and 2019 DOT reports show that Columbia replaced 303 miles of unprotected bare steel and 48.5 miles of cast iron/wrought iron, which is a total replacement of 351.5 miles of at-risk mains, for the 4-year period from 1/1/2016 to 12/31/2019. The 2015 DOT report indicates that Columbia had 1,532.7 miles of at-risk mains at the end of 2015. Therefore, Columbia replaced 351.5 out of 1,532.7 miles (22.9%) of at-risk mains in a 4-year period.

Q. In his direct testimony, witness Niambele states that "The Company replaced 303 miles of bare steel in 5 years with an average of 60 miles per year." Do you agree with witness Niambele?

A. No. As stated above, the difference in miles of main between the 2015 and 2019 DOT reports represents replacement for the four year period from 1/1/2016 to 12/31/2019. Therefore, Columbia replaced 303 miles of bare steel in four years with an average of over 75 miles per year. Columbia also replaced 48.5 miles of cast iron/wrought iron during the same four year period. The combined data for bare steel and cast/iron wrought iron replacement demonstrates that Columbia replaced an average of over 87 miles of at-risk pipe per year during that four year period.

Q. In his testimony, witness Niambele states that "Columbia will not meet its planned 2029 target date for replacement of all bare steel, cast iron and wrought iron mains." How do you respond?

A. Mr. Niambele's basis for such contention is to divide total mains to be replaced by the period of years for replacement, and conclude that at Columbia's current replacement pace, Columbia will not complete replacement by 2029. As Mr. Niambele acknowledged on page 8 of his testimony, Columbia may be ahead of its projected 5 year goal in its LTIIP. In fact, Columbia is currently on track to meet the amount of replacement pipe provided for in its LTIIP for the period of 2018-2022. However, Columbia's ability to meet its projections cannot be measured by a straight line, average approach. Columbia has never asserted that it would achieve the "average" pipeline replacement each year. Rather, each project presents unique issues, such as locational factors, which impact the mileage replaced each year. For example, if a project involves pipe replacement in a location where other utilities are located or constraints on work hours are imposed, the amount of pipe replaced per day could be less than for other projects. It is more relevant to compare actual vs. projected replacements over a shorter time frame.

Q. What does Mr. Effron recommend with regard to Columbia's capital program?

A. On page 7 of his direct testimony, witness Effron adjusts the Company's 2021 forecast of plant additions used to calculate the Company's projected 2021 rate base, stating that he does so because the Company's "forecasted plant additions for 2021 are well in excess of the forecasted plant additions for 2020 and the actual plant additions in 2018 and 2019.".

Q. How does Mr. Effron arrive at his adjustment and what is the result?

A. Mr. Effron averages the plant additions for the years 2018 through 2020 to determine that the Company's plant additions for 2021 should be approximately $261.77 million (with corresponding adjustments to depreciation reserve and accumulated deferred income taxes), instead of the Company's projected $338.55 million plant addition spend as provided in Company witness Shultz's Ex. 108. Mr. Effron's adjustment to Columbia's 2021 plant additions effectively results in the Company's plant additions being substantially lower than in the years 2019 and 2020.

Q. Do you agree with Mr. Effron's recommended adjustment?

A. No I do not agree. Mr. Effron's conclusion that the Company's 2021 forecasted additions to plant is unreasonable and is based exclusively on the fact that the 2021 forecasted additions exceed the Company's plant additions in recent years. He does not, however, state that the forecasted plant additions themselves are unnecessary or unreasonable. The Company has demonstrated that its forecasted plant additions are necessary and reasonable, as they directly relate to maintaining the safety and reliability of Columbia's natural gas distribution system. Further, these plant additions include defined, planned projects, as outlined below that are ready for 2021 execution.

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 are more than the forecasted plant additions for the past three years that they need to 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"). A great portion of the plant additions for 2021 include approximately $258 million in age and condition spend, which is related to the Company's infrastructure replacement program. Further, Columbia has already identified a preliminary roster of 2021 replacement projects which will comprise the age and condition portion of the spend.

In addition to its age and condition spend, on page 6 of his direct testimony Mr. Effron references $31 million that is part of Columbia's 2021 plant additions in the betterment category. Betterment is part of the Company's LTIIP, and approximately $10 million has been slated for the New Castle odorization project, and $23 million for the Airport/Southern Beltway Corridor modernization project.

As described in Columbia's LTIIP, DSIC eligible property includes all materials of piping, service lines, excess flow valves, regulators, risers, meter bars and meters that must be replaced in order to repair, improve or replace eligible property that is part of the utility's distribution system. 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.

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 plant additions in the amount of approximately $338.55 million 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 is ready 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 2021 plant addition spend downward is inappropriate and should be rejected.

Q. Why is it improper to average plant additions from the past for a future plant addition amount?

A. As stated in Company witness Shultz's rebuttal testimony, an average should only be used when a company cannot support its projects. The Company has provided support herein for its 2021 plant additions. Further, as noted above on page 4 of my rebuttal testimony, it is inappropriate to use an "average" pipeline replacement amount for each year and similarly, it is inappropriate to average plant additions for forecasting future years. The Company designs projects year over year and the projects change each year. Each project presents unique issues, such as locational factors, which can impact both the mileage and spend associated with each project.

Further, as shown in the table below, the Company's plant addition spend is not the same year over year and it has increased each year (with the exception of 2018). Further, the table below provides actuals and projections relative to the Company's plant additions from 2016 to present. The Company has met its historic commitments in identifying projected spend and has even exceeded its commitments.

Table 1: Plant Addition Estimates v. Actuals from 2016-2021

Year	Plant Addition Projections	Plant Addition Actuals*
2016	$201 million	212 million
2017	$241 million	246 million
2018**	$256 million	209 million
2019	$258 million	294 million
2020	$289 million	TBD
2021	$338 million	TBD

*Net additions less retirements
**2018 is unique as CPA sent resources to Massachusetts and as a result some of the 2018 plant addition work was completed in 2019.

Therefore, the Table above demonstrates that Columbia consistently and accurately projects its plant addition spend year over year (with the exception of 2018 that was made up in 2019) thereby meeting its commitments related to replacing aging infrastructure and providing safe and reliable service to its customers.

Q. Please summarize why Columbia's 2021 plant addition projections are reasonable.

A. Columbia's 2021 plant addition projects in the amount of $338.55 million are reasonable for several reasons. First, Columbia's plant additions include an increase in spend related to the replacement of aging infrastructure on its system. Second, Columbia's plant additions include spend related to necessary capital safety projects related to odorization. Third, Columbia's 2021 plant additions include spend related to the modernization of its infrastructure. For the reasons stated above, Columbia has demonstrated that the forecasted increase in plant additions for 2021 is reasonable and has outlined the plans for the increased spend relating to maintaining the safety and reliability of its system.

III. Pipeline Replacement Costs and Restoration Costs

Q. Mr. Niambele highlights two projects that stood out because of the high restoration costs relative to the total project costs. Can you provide further information on these projects?

A. Yes. Both projects were in an urban area and required more restoration than a typical project. The South Side, Phase I project consisted of laying pipeline under pavement along Sarah Street, 25th Street and Jane Street because the buildings are close to the sidewalks in this area of Pittsburgh. The City of Pittsburgh required 3.5 inch "mill and overlay" of half the width of each street and most of the intersections. Similarly for the Glenwood project, the Borough of Ambridge required "mill and overlay" as well as sidewalk restoration.

Q. What are witness Niambele's recommendations with respect to replacement and restoration costs?

A. On page 13 and 14 of his direct testimony, Mr. Niambele offers four recommendations for cutting restoration costs. He recommends that Columbia: 1) make an effort to negotiate better contracts; 2) coordinate projects with other utility companies and local governments to keep cost down; 3) itemize expenses on pipeline replacement projects; and 4) consider a competitive bid process for paving. He also recommends that the Company draft a cost reduction plan to be submitted to I&E's Gas Safety Division within 60 days following the conclusion of this case.

Q. Does Columbia agree with witness Niambele's recommendations regarding pipeline restoration costs?

A. No. The recommendations made by Mr. Niambele are already part of the Company's existing processes to plan and execute pipeline replacement projects. Further, these processes are continuously evolving based on the current nature and circumstances of the long term effort undertaken by the Company in replacing its infrastructure. Accordingly, Columbia disagrees with Mr. Niambele that his four suggestions would result in decreases to restoration costs, and disputes any suggestion that it fails to spend prudently on restoration costs. Additionally, the Company does not believe that the cost reduction plan recommended by Mr. Niambele is necessary for the same reasons that the individual recommendations are not necessary. The Company is already working on Mr. Niambele's suggestions as it is working to reduce restoration and replacement costs by negotiating competitive contracts, tracking pipeline project costs and coordinating with other utilities and municipalities.

Q. Can you provide details as to Columbia's existing processes of the four categories identified by witness Niambele?

A. Yes. Columbia employs reputable contractors to support its accelerated infrastructure replacement program. Additionally, the Company is focused on negotiating with these contractors to obtain fair pricing, while ensuring the contract language clearly defines costs covered in the unitized pricing. However, any revisions to existing blanket contract language, due to process or procedural changes which are essential to providing safe and reliable services to our customers, continue to contribute to rising contractor costs. The efforts to minimize costs associated with such changes is ongoing.

Second, Columbia's current practice of coordinating projects with other utility companies and local governments is already part of our planning process. Our ability to collaborate with these parties is largely contingent upon their willingness to do so, which is not directly within the Company's control. As represented in my direct testimony on pages 9 through 14, Columbia provides examples of its efforts to proactively engage in addressing municipal issues as well as successful outcomes relating to challenging restoration requirements that the Company considers to be atypical. In addition to these examples, Columbia has also successfully reached agreements regarding restoration requirements with the following local governments: the City of New Castle, Gettysburg Borough, West Manchester Township, Dallastown Borough, City of Washington, Peters Township, Edgeworth Borough, Coraopolis, East Washington Borough, Emsworth Borough, Bellevue Borough, Ben Avon, Berlin and California. Further, the internal audit of the 10 largest projects competed following the Company's 2014 base rate proceeding independently confirmed that coordination with other utilities and municipalities is an existing part of the Company's project planning process. Additional discussion of this audit can be found in Company Witness Tubbs rebuttal testimony at Columbia Statement 1-R.

Third, Columbia already tracks its expenses for pipeline replacement projects, as all costs, including restoration costs, are subject to Commission review for prudence. Columbia continuously monitors the progress of each project (expenditures year-to-date) and what remains to complete each project (projected forecast) inclusive of restoration. Changes in projected costs are then accounted for accordingly for each particular project.

In consideration of a competitive bid process for paving, Columbia evaluates restoration costs, but has to balance cost containment strategies to ensure the opportunities meet the needs of both the infrastructure replacement program as well as general operations and maintenance activities. By negotiating area specific contracts, Columbia may be able to lessen the cost of scattered restoration generated from routine operations and maintenance work, but this process could adversely impact infrastructure replacement efforts. Currently, Columbia's contractors coordinate and manage restoration activity based off projected project completion and overall scope, which is also reflected in their unitized pricing. An inherent risk of a competitive bid process for paving is scoping restoration requirements well before projects are completed. The Company cannot wait until after pipe installation is completed to bid a paving project, as this would result in delayed completion that would be unacceptable to customers and local communities. However, undertaking a bid process before the project is completed presents substantial risk of inaccurate assumptions due to the nature of construction and the potential to change project design because of unforeseen circumstances. After the bid process, any scope changes would require a change order for bid work and would also add risk to on-time completion.

Q. In his testimony, witness Niambele states that "The Company could also conceivably save on paving restoration costs when the option of pipeline placement in a private right of way vs. a public right of way exists for a

specific project." Does Columbia take this into consideration when designing projects?

A. Yes. Columbia already contemplates, and uses, private rights-of-way in pipeline replacement projects when private rights-of-way are available and appropriate for the project. During the design phase of a project, right-of-way options undergo a comprehensive review and all alternatives are considered, including the possibility of using private rights-of-way. The determination of public vs. private rights-of way is based on the unique circumstance of each project.

Further, Mr. Niambele's implication that private rights-of-way are readily available or a least cost alternative is inaccurate. Feasible private rights-of-way may not exist in proximity to existing pipes. In addition, in many urban and suburban areas where Columbia serves, there may be little to no open land between buildings and the street, making private rights-of-way impossible to consider. Private rights-of-way cost money to acquire and, therefore, add to the overall cost of restoration. Further, private rights-of-way may also result in additional costs for things like tree cutting or crop replacement, which may require ongoing vegetation management. Moreover, even where the use of a private right-of-way is feasible, the Company may still have to cross a municipal street at road intersections and to install service lines, which would require the Company to obtain a permit, and to incur street repaving costs. Columbia does, where possible, install pipelines within the street right-of-way in the berm of a road, which can reduce paving costs in some cases, depending upon factors such as the number of service lines that must cross the street.

Q. What is the Company doing to manage the ongoing costs of restoration?

A. Columbia is focused on managing costs and making prudent capital investments that benefit our customers. The Company has undertaken efforts to manage restoration costs in accordance with the settlement of its 2014 base rate case. These efforts are ongoing.

As one of seven distribution companies within the NiSource family making infrastructure capital investments, Columbia is 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. Columbia's service territory spans over 440 municipalities in the Commonwealth of Pennsylvania, each of whom are authorized to set their own municipal ordinances related to street openings. Columbia incurs restoration costs on pipeline replacement projects in compliance with the ordinance of the municipality in which the pipeline is replaced. As Columbia witness Tubbs notes in his rebuttal testimony, in its Opinion and Order approving the major modification of Columbia's first LTIIP, the Commission recognized Columbia's efforts to control restoration costs, but observed that local government restoration requirements are, to some extent, outside of the Company's control.

In response to the Commission's 2015 request to engage local municipalities on the rising costs of restoration and permits, Columbia has formalized a restoration review process in which a cross-functional team reviews projects where restoration has historically been done. As a first-step, the Company will sit down with a municipality during the design stage of a project and attempt to agree on what the final restoration (and permitting) requirements will be prior to the start of construction. In my direct testimony, I reviewed in detail the progress Columbia has made to date. These efforts, although sometimes lengthy and time consuming, have proven fruitful in providing win-win outcomes. These efforts will continue into the future.

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	)	
	)	
vs.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
KIMBERLY K. CARTELLA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

Q. Please state your name and business address.

A. My name is Kimberly K. Cartella, and my business address is 3101 North Ridge Road East, Lorain, OH 44055.

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

A. I am employed by NiSource Corporate Services Company ("NCSC") as the Director Compensation. I develop and implement strategies for compensation programs provided to the employees of NiSource Inc. ("NiSource") and its subsidiaries, including Columbia Gas of Pennsylvania, Inc. ("CPA", "Columbia" or the "Company").

Q. Please describe your educational background and professional experience.

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"). I have worked for NiSource in a human resources capacity since 1999.

I have held the position of Director Compensation at NiSource since January 2019. Prior to that, I was Manager Compensation, Senior Compensation Analyst, Senior Human Resource Consultant, and 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, and Docket No. 2018-2647577.

Q. What is the purpose of your rebuttal testimony?

I will explain changes in the merit increase program that occurred after the filing of this case on April 24, 2020. Also, I will respond to the testimony served in this proceeding by the Bureau of Investigation and Enforcement ("I&E") witness John Zalesky regarding employee incentive compensation expense. I will also respond to the testimony served in this proceeding by Office of Consumer Advocate ("OCA") witness David Effron with respect to compensation and stock awards.

Q. What changed in the merit process, and how is the cost of service impacted?

A. Since the filing of the case on April 24, 2020, modifications to the annual merit process have been made with regard to timing and percentage. Typically in the past, merit increases for non-union employees (exempt and non-exempt) became effective annually on June 1. Merit increases of 3% for non-union non-exempt employees became effective on June 1, 2020 as scheduled. For non-union exempt employees in manager positions and below, NiSource elected to delay merit increases until September 1, 2020 and forego merit increases for non-union exempt employees in director and above positions.

Additionally, merit increases will be awarded on September 1, 2020 to non-union, exempt employees in manager positions and below, and will be 2.3% as opposed to the 3.0% included in the original budget reflected in the Future Test Year ("FTY").

The next merit increase process for all nonunion nonexempt and exempt employees is anticipated to begin February 2021, during the Fully Projected Future Test Year ("FPFTY").

Q. Why has NiSource elected to make these changes?

A. Decisions regarding the timing and level of merit increases were made within the context of the operation of the 2020 budget and financial constraints. These changes are driven by current decreased cash flow from decreased revenues and the balancing of priorities within the overall NiSource compensation program.

Q. How do these changes impact the Company's claim for O&M expense and where are they reflected?

A. These changes serve to reduce overall labor expense in both the FTY and the FPFTY and are addressed in Company witness Miller's Rebuttal Testimony (Columbia Statement No. 4-R) and detailed in Exhibit KKM-3R.

Q. Please describe NiSource's total rewards philosophy.

A. NiSource's "total rewards" philosophy is to reward employees competitively in comparison to its peers in the utility industry, as well as general industry employers, in order to attract, retain and motivate qualified employees, while consistently meeting its requirements to provide safe, reliable, and cost-effective service to its customers. Competitively rewarding employees motivates them to achieve important goals, retains their significant operational knowledge and value, and reduces costly turnover. The Company has goals related to customer service, quality of service, containment of costs, and safety which are customer-oriented goals and by which every Company employee is expected to abide. Employees are accountable for these goals and employees take action to reinforce those goals in order to achieve incentive rewards.

Q. Please briefly describe the position of Mr. Zalesky 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 $373,749 in FPFTY Incentive Compensation to be paid by the Company.

Q. Do you agree with Mr. Zalesky's recommendation?

A. No. As noted by Company witness Krajovic on pages 17-19 of 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. Furthermore, incentive compensation is based upon a combination of factors including the Company's overall performance on various customer, safety, and financial metrics as well as individual employee contributions and performance, as supported by NiSource's "total rewards" philosophy.

Q. Please briefly describe Mr. Effron's position regarding stock awards and 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 $775,000 in FPFTY Incentive Compensation to be paid by the Company. Mr. Effron also recommends 100% disallowance of costs related to stock rewards, or a total of $2.3 Million. Mr. Effron opines that stock compensation is solely based on attainment of financial goals and should be removed from the cost of service.

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 based on historical results. Witness Krajovic addresses this concern on pages 17-19 of her rebuttal testimony. Mr. Effron's claim that stock compensation is solely related to Columbia's financial goals is incorrect. Stock compensation does provide benefits to Columbia's customers. Furthermore, incentive compensation is based upon a combination of factors including the Company's overall performance on various customer, safety, and financial metrics as well as individual employee contributions and performance, as supported by

NiSource's "total rewards" philosophy. Please note that I&E witness Zalesky did not disallow any portion of stock awards.

Q. Why does NiSource provide incentive compensation and stock awards?

A. Stock awards and incentive compensation 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. The Company recognizes that the stock compensation awards should not be based upon financial metrics alone, but should also include the achievement of goals that are beneficial to customers. Starting in 2018, additional stock compensation metrics were added that include customer value goals of safety, customer, financial, culture, and environmental components. The safety goal is to have top decile results in the National Safety Council Barometer Survey. The customer goal is to have top quartile performance in the J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies. The financial goal is to control the Operations and Maintenance ("O&M") cost per customer by maintaining flat O&M expenses. The culture goal is top quartile performance in the Employee Engagement Survey Culture Index. The environmental goal is to reduce greenhouse gas emissions by approximately 2 million tonnes.

In addition, stock compensation is a common element of compensation at certain levels of organizations throughout the U.S. and, as such, these costs should be allowed. Stock compensation awards allow Columbia, NCSC and NiSource 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 compensation awards be recovered in base rates?

A. If the Commission disallows recovery of stock compensation, 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 award compensation 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 compensation is an appropriate cost of providing reliable service to Columbia's customers. If the Company did not provide stock compensation, 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 costs, relocation costs, 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 Krajovic in her rebuttal testimony.

Q. Does this complete your rebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pa. Public Utility Commission	:	
v.	:	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	:	

REBUTTAL TESTIMONY OF

JAMES H. CAWLEY

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

August 26, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND CURRENT POSITION.

A. My name is James H. Cawley. My consulting business address is 1020 Kent Drive, Mechanicsburg, PA 17050.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am an independent consultant and an attorney. As an attorney, I am also Of Counsel to the law firm of SkarlatosZonarich LLC, 320 Market Street, Suite 600W, Harrisburg, PA 17101.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

- Before my appointment to the Commission in 1979, I served as majority counsel to the Pennsylvania Senate Consumer Affairs Committee where I was a major draftsman of substantial amendments to Pennsylvania's public utility laws as a part of the two-year effort of that committee under the chairmanship of Senator Franklin L. Kury to reform Pennsylvania's public utility laws for the first time since their enactment in 1937. During that effort, I spent a great deal of time studying the history of public utility regulation and public utility ratemaking in the United States. The Kury Committee's work culminated in passage of Acts 215 and 216 of 1976. I then worked with the Pennsylvania Joint State Government Commission to codify those laws into the Pennsylvania Public Utility Code. In 1977, I was appointed chief counsel to the Senate Democratic Floor Leader.

I then served two terms as a member of the Pennsylvania Public Utility Commission, the first from 1979 to 1985 during which time I co-authored with Norman

James Kennard a guide to ratemaking before the Commission.[1] My second term was from 2005 to 2015. I was Chairman of the Commission from 2008 to 2011.

Between my two terms, I primarily represented clients before the Commission while serving as the managing partner of the Harrisburg office of the New York City law firm of LeBoeuf, Lamb, Greene & MacRae LLP (1988-1996) and then as a partner of the Harrisburg law firm of Rhoads & Sinon LLP (1996-2005).

From 1998 to 2003, I served on the Board of Directors of Pennsylvania-American Water Company, and from 1991 to 1999 on the Pennsylvania Energy Development Authority. Since 2016, I have served on the Board of Directors of The York Water Company.

From 1994 until 2014, I was an adjunct professor of federal administrative law and appellate advocacy at Widener University Commonwealth Law School in Harrisburg.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. On behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), the purpose of my testimony is to provide my expert opinion regarding the direct testimony of Scott J. Rubin filed on behalf of the Pennsylvania Office of Consumer Advocate on July 28, 2020, which recommends that, given the economic effects of the current pandemic over the last five-month period, the Commission completely deny Columbia's requested rate increase based on a theory of public utility ratemaking that rejects cost-of-service

[1] James H. Cawley and Norman James Kennard, A GUIDE TO UTILITY RATEMAKING BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (2d ed. 2018) (hereinafter Cawley & Kennard Guide), *available at* http://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf.

ratemaking principles and substitutes an ad hoc, overly broad, asymmetric, and essentially undefined customer affordability standard for ratemaking.

I note that other witnesses besides Mr. Rubin generally advocate against Columbia's proposed rate increase based upon the occurrence of the COVID-19 pandemic. My testimony can also be understood to generally respond to the policy-based arguments each of these witnesses raised on this issue.

Q. ARE YOU PRESENTING ANY EXHIBITS?

A. Yes, I am sponsoring the responses of OCA to various discovery requests regarding the Direct Testimony of Jerome D. Mierzwa. All of these responses are included in Exhibit JHC-1 and include the following responses:

- Responses of OCA to Columbia Set II, No. CGP-OCA-II-1.
- Responses of OCA to Columbia Set II, No. CGP-OCA-II-2.

I am also sponsoring JHC-2 (Mr. Rubin's direct testimony in *Pennsylvania Public Utility Commission, Paul Meaden, and James A. Dimperio v. Colony Water System, Ltd.*, Docket Nos. R-00922375; R-00922375C001 & C0002, Order entered June 10, 1993).

Q. DO YOU HAVE ANY PRELIMINARY MATTERS TO ADDRESS?

A. Yes. I express the same disclaimers as Mr. Rubin does at page 3 of his testimony. My testimony deals with regulatory policy issues. Given the nature of public utility regulation, much of the public policy in this field is constrained by and contained in decisions by regulatory agencies and courts; or in statutes, ordinances, or regulations. I cite to these types of sources, not as a legal opinion (although I am qualified to provide expert testimony as a regulatory attorney in Pennsylvania), but rather as sources supporting my expert opinion concerning appropriate public policy and regulatory practice.

My references to a "utility" (singular or plural) refer to Columbia. My references to "investors" refer to Columbia's investors.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

Columbia should be encouraged to continue its remarkable leadership and progress in replacing cast iron, wrought iron, and bare steel mains and expanding its system to new customers by receiving responsible rate relief to continue the extensive work that remains.

Mr. Rubin recommends that the Commission "deny Columbia's request in its entirety and keep Columbia's existing rates (and all other tariff provisions) in effect."[2] His recommendation should be rejected for the following reasons:

1. Mr. Rubin abandons well-established and longstanding cost-of-service and normalized test year ratemaking in favor of a method that forsakes the required *balancing* of investors' and customers' interests by giving exclusive consideration to customers' interests when prevailing economic conditions (such as the current pandemic) make it difficult for an undetermined number of them to pay their utility bills.
2. Mr. Rubin's proposed method of conducting a general rate case short circuits the traditional and required ratemaking process before it begins and imposes a preordained result, giving Columbia no opportunity to prove its case. It is regulation by surveys, polls, and selective reference to economic data to determine Columbia's revenue requirement. Fundamental ratemaking principles require that a utility's revenue requirement be determined principally by an examination of the utility's financial data. Customer interests must be considered as a matter of the required balancing of interests but cannot be completely overriding or exclusively determinative.
3. Mr. Rubin's proposed ratemaking method and recommendation to deny all rate relief is especially unfair to Columbia which, since 2007, has provided remarkable leadership in replacing cast iron, wrought iron, and bare steel mains, even foregoing payment of dividends to its parent company to do so, and the Commission has consistently provided responsible rate relief in support of these replacement efforts.
4. Mr. Rubin's recommendation would also be unfair to Columbia's customers who would be deprived of planned main replacements, and who with their

[2] OCA St. No. 1, p. 23.

communities would suffer the loss of economic investment and job opportunities.

5. Mr. Rubin's recommendation that, in times of economic distress, just and reasonable rates may be set within a "null" zone (reflecting the value and affordability of service to customers) that is below—instead of *within*—the traditionally regarded zone of reasonableness simply invites the Commission to confiscate Columbia's property.

6. His method is overly broad because all customers, including most customers who remain employed and even the wealthy would pay little or no rate increase.

7. His method is an arbitrary and ad hoc method of setting rates that is not predictable because it lacks adequate standards. It therefore would be unacceptable to investors that have historically provided capital to Columbia and other Pennsylvania utilities with the result that capital will become more expensive and potentially not available in difficult economic conditions.

8. His proposal is fundamentally asymmetric because it would produce rates below the traditional zone of reasonableness during an economic disruption, but it undoubtedly would not produce rates above the zone of reasonableness in good economic times.

9. His method contravenes the Legislature's intent in enacting Act 11 of 2012 (creating a Distribution System Improvement Charge ("DSIC") and the Fully Projected Future Test Year ("FPFTY")) to ensure that Commission-determined rates provide as nearly as possible Columbia's needed revenues at the time that the rates are put into effect, for it to make desired infrastructure investments, and to increase employment opportunities in the Commonwealth.

10. He fails to recognize the important programs Columbia maintains for those ratepayers who experience ability to pay situations, and he ignores substantial government aid provided in response to the COVID-19 pandemic in determining whether the increase requested is affordable or not.

Rather than adopting Mr. Rubin's ratemaking solution to assist customers in times of pandemic or other serious economic dislocation, the Commission should: (1) continue its traditional cost-of-service and normalized test year ratemaking, and (2) continue to ensure that Columbia's customers in financial need receive all possible help from Columbia and from state and federal COVID-19 relief funding.

III. MR. RUBIN'S RECOMMENDATION AND REASONS

Q. WHAT DOES MR. RUBIN RECOMMEND AND FOR WHAT REASONS?

A. Mr. Rubin recommends that the Commission "deny Columbia's request in its entirety and keep Columbia's existing rates (and all other tariff provisions) in effect."[3]

Section 1301 of the Public Utility Code[4] requires that "[e]very rate made, demanded, or received by any public utility … shall be just and reasonable, and in conformity with regulations or orders of the commission." In Mr. Rubin's view, however, economic circumstances and affordability determine the justness and reasonableness of rates, viewed solely from the perspective of the utility's customers.[5]

He contends that public utility rates should be adjusted to coincide with the ability of (an unspecified number of) Columbia's customers to pay their utility bills when their incomes have been diminished (an unspecified degree) by current economic conditions.

He complains that traditional rate cases focus too much on investors' interests and too little on customers' interests.[6] He states that "ideally, rates should be set within a 'zone of reasonableness' which represents a range within which all of the relevant interests intersect,"[7] but "if interest rates or the levels of investment become very high, investors' minimum return requirements may become so high as to fall above the range of rates which consumers can afford to pay. When this happens, the rate regulators may have to set rates which fall outside of the normal zone of reasonableness [i.e., into a "null" zone lower than

[3] *Id.*, p. 23.

[4] 66 Pa.C.S. § 1301.

[5] OCA St. No. 1, p. 5.

[6] *Id.*, p. 8.

[7] *Id.*, p. 5.

the lowest reasonable rate within the zone],"[8] because the interests of investors and consumers have "diverged."[9]

He claims that, because Columbia's filing is based on data from "normal" economic conditions which do not presently exist due to the current pandemic, the Commission cannot rely on such data to set just and reasonable rates.[10] Instead, he argues, the Commission "must act within the broad public interest"[11] and focus on what are just and reasonable rates under these extraordinary conditions,[12] because "what may have been a 'just and reasonable' rate a few months ago may be unreasonable today."[13]

He also contends that because "regulation is supposed to be a substitute for market forces, … competitive businesses cannot sustainably raise prices when their customers' incomes have decreased significantly"[14] … and "That is the real-world competitive market that regulation is trying to mirror."[15]

Finally, he concludes that, "if economic conditions change such that rates become unaffordable to many customers, rates may need to be reduced in order to remain 'just and reasonable' from the perspective of customers."[16]

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[8] *Id*., p. 7 (and Figure 2 entitled "Divergent Interests: A Null Zone of Reasonableness").

[9] *Id*., p. 6.

[10] *Id*., pp. 3, 23-24.

[11] *Id*., p. 8.

[12] *Id*., p. 19.

[13] *Id*., p. 9.

[14] *Id*.

[15] *Id*., p. 24; *see also* p. 4 ("It is often stated that regulation is a substitute for competitive market forces.").

[16] *Id*., p. 5.

Consequently, he substitutes customer-determined value and affordability for cost-of-service, rate base-rate of return ratemaking to determine rates for Columbia's customers.

IV. MR. RUBIN'S RATEMAKING METHOD APPLIED

Q. IN MR. RUBIN'S VIEW, HOW SHOULD COLUMBIA'S RATE CASE PROCEED?

A. Applying his principles as I understand them, Columbia's rate case would proceed as follows:

> (1) a determination of whether an economic dislocation exists, such as that caused by the COVID-19 pandemic;
>
> (2) an assessment of the severity and effects of the economic dislocation on Columbia's residential and small business customers by consulting various resources that are extraneous to Columbia's financial condition, such as unemployment data in Columbia's service area, Federal Reserve System surveys on household finances, Federal Reserve Bank of Philadelphia surveys of the business community, U.S. Census Bureau estimates of job losses, Electric Power Research Institute surveys of customers' concerns about paying their utility bills, and examples of utility regulatory bodies in Canada and the United States postponing or denying rate increase requests);[17] and
>
> (3) a general conclusion (derived without discernable standards or dollars and cents supporting data), based on selectively chosen information, that an indeterminate number of Columbia's customers may not be able afford to pay Columbia's proposed increase in rates.[18]

If these subjective criteria lead to such a conclusion, he argues that the Commission is precluded from lending any credence to Columbia's projections for its fully projected future test year ("FPFTY")—and "essentially every aspect of Columbia's projections"—because there is too much uncertainty.[19] The Commission is also precluded from assuming that the rates based on such data will be just and reasonable.[20]

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[17] *Id*., pp. 10-18, 21-22.

[18] *Id*., pp. 5, 9.

[19] *Id*., p. 25.

[20] *Id*.

The rate case ends there, without giving Columbia an opportunity to present or prove its case, and existing rates continue without change.[21]

Q. WHAT IF MR. RUBIN ACTUALLY INTENDS THAT COLUMBIA BE GIVEN THE OPPORTUNITY TO PROVE ITS CASE?

A. I do not interpret his testimony as intending that because it only proposes determinations of affordability and seriousness of an economic dislocation that, if established, are dispositive. The rate case would end there.

Even if Mr. Rubin intends that normal rate case procedures occur, the proceeding would be a pointless exercise because the result would be preordained if a serious economic dislocation exists and the rate increase is claimed to be unaffordable to some customers. His ratemaking method would make it impossible for Columbia to carry its burden of proof under Section 315(a)[22] no matter what evidence it introduced into the record regarding its need to increase its revenues.

V. THE UNFAIRNESS OF APPLYING MR. RUBIN'S RATEMAKING METHOD TO COLUMBIA AND ITS CUSTOMERS

Q. WOULD IT BE FAIR TO APPLY MR. RUBIN'S PROPOSED "AFFORDABILITY" RATEMAKING METHOD TO COLUMBIA?

A. Mr. Rubin's ratemaking method and his resulting recommendation to deny the requested increase entirely would be unfair to Columbia and unwise because of the long-term effect on Columbia's customers. The same is true of Mr. Rubin's recommendation "if the economic situation worsens significantly and cash flow becomes a concern for

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[21] *Id*., p. 23 ("To put all of this in terms of utility ratemaking: it would be neither just nor reasonable for Columbia to increase its rates at this time. The Commission should deny Columbia's request in its entirety and keep Columbia's existing rates (and all other tariff provisions) in effect.").

[22] 66 Pa.C.S. § 315(a).

Columbia"[23] that Columbia defer construction projects "that are not needed to ensure the current provision of safe and reliable service to existing customers," such as "growth-related projects or system rehabilitation activities that are longer-term in nature (that is, projects that are not needed to ensure current levels of service within the next six to 12 months)."[24]

Q. WHY WOULD THE APPLICATION OF MR. RUBIN'S METHOD BE UNFAIR TO COLUMBIA?

A. It would be particularly unfair to Columbia because of its leadership in accelerating its replacement of cast iron, wrought iron, and unprotected bare steel mains in Pennsylvania, and especially so because Columbia has not paid dividends to its parent company and retained earnings to do so.[25]

When I returned to the Commission in 2005, the Commission was very concerned about the urgent need for natural gas distribution companies to replace these types of aging mains. We began encouraging NGDCs to accelerate their replacement efforts, and we stepped up our legislative advocacy for enactment of a mechanism for natural gas infrastructure improvements.[26] This advocacy eventually led to enactment of Act 11 of 2012 which expanded the water utility-only Distribution System Improvement Charge to NGDCs and other jurisdictional fixed utilities and added a FPFTY.

Meanwhile, Columbia did not wait for the expansion of the DSIC to NGDCs. As the testimony of Columbia witness Robert M. Kitchell (Columbia St. No. 14) relates in

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[23] OCA St. No. 1, p. 26.

[24] *Id*.

[25] Columbia St. No. 8-R, p. 5.

[26] *See, e.g.*, this October 16, 2007, press release: http://www.puc.state.pa.us/about_puc/press_releases.aspx?ShowPR=1858.

detail, Columbia began an accelerated replacement of bare steel, wrought iron, and cast iron pipe in 2007 and has since retired 5,699,833 feet of such mains.[27] During that time, the cost of main replacement has gone from $81.25 per foot in 2008 to $235.00 per foot today.[28] As part of its Distribution Integrity Management Program ("DIMP"), Columbia plans to spend $265 million annually in capital expenditures in the period 2020-2024.[29]

With regular, rational rate increases, usually by approving negotiated settlements, the Commission, with my concurrence, has supported these replacement efforts.

In fact, Columbia has been so beneficially aggressive with main replacements that its DSIC quickly reaches the 5% of billed revenue quarterly recovery limit.

Moreover, Mr. Rubin's recommendation that Columbia defer construction projects that are not needed to ensure safe and reliable service (he suggests deferral of growth-related projects and system rehabilitation activities) encompasses nearly all of Columbia's construction budget consisting of replacement of "priority" (most in need) pipe and new connections.

Regarding priority mains, it is my opinion that the Commission would not look favorably on cessation or significant slowing of Columbia's impressive main replacement momentum, especially given the magnitude of replacements still to be done.

As for growth-related projects, new service connections comprise a relatively small percentage of Columbia's total construction budget. As Columbia's response to standard data request GAS-RR-014 demonstrates, of the Company's projected capital budget of $375 million in the FPFTY, only $37 million is slated for new business. Even if Columbia

[27] Columbia St. No. 14, p. 3.

[28] *Id*., p. 4.

[29] *Id*., pp. 14-15.

adopted Mr. Rubin's recommendation to defer "growth-related projects and system rehabilitation activities," that would hardly obviate the need for this rate increase.

Further unfairness to Columbia would result if no increase is granted. Its requested increase would go into effect on January 23, 2021, a year and a month after the end of the FPFTY on December 31, 2019 in its last rate case. With no increase now, Columbia will not receive a return on or of the huge rate base-qualifying additions added in 2020 and the significant additions planned for 2021. In addition, it is not clear under Mr. Rubin's approach when Columbia would even be permitted to reapply for such rate relief. That delay in investment recognition, combined with no rate increase in this case (resulting in a projected overall rate of return of a paltry 4.86% for 2021[30]), spells a cessation of construction at current levels and difficulty raising capital at reasonable cost to complete needed construction over the next decade.

Finally, at the request of various stakeholders, Columbia already delayed filing this rate case for over a month, which represents a loss in revenue that never can be recouped. For further elaboration of this "delay loss," please refer to the Rebuttal Testimony of Columbia witness Andrew S. Tubbs (Columbia St. No. 1-R).

Therefore, in light of its extraordinary replacement efforts and the Commission's steadfast support for them, it is ludicrous to suggest that responsible rate relief should be withheld at this point, especially when the testimony of the other OCA witnesses concede that at least a $31 million rate increase is justified, even after all of their adjustments and a proposed very low equity return allowance.[31]

[30] Columbia Ex. 2, Schedule 2, p. 1 of 1.

[31] OCA's calculation of only a $31 million revenue deficiency is not supportable, as demonstrated by Columbia's various rebuttal testimonies.

Q. WHY WOULD THE APPLICATION OF MR. RUBIN'S METHOD BE CONTRARY TO CUSTOMERS' INTERESTS?

A. The plain answer is that the faster aging pipe is replaced, the safer the system is. Mr. Rubin's method and recommendation to slow or delay construction investment at current levels, will lead inevitably to less safe and reliable service.

Adoption of his method and recommendation would also compromise or eliminate substantial economic benefits and jobs in Columbia's service territory[32] contrary to the Legislature's intent in enacting Act 11 of 2012: to ensure that Commission-determined rates provide as nearly as possible the utility's needed revenues in the period in which rates will be in effect to encourage it to make desired infrastructure investments and to increase employment opportunities in the Commonwealth.

If consistently reasonable, rational, and carefully balanced (between ratepayers and investors) ratemaking is abandoned by, for example, adopting one-sided measures like Mr. Rubin's approach, the result for Columbia and its customers will be (1) a loss of confidence by the investment community in the Commission's willingness to provide Columbia with the financial wherewithal to persevere with its facilities improvement efforts; (2) a perception that investing in Columbia is riskier; and (3) therefore a demand for a greater yield on any investments made in Columbia's securities, which inexorably are passed onto to Columbia's customers in higher rates. Instead of seeing progression and hard-fought momentum maintained, investors would see regression and backsliding.

[32] For a more detailed discussion of the economic and jobs impact that Mr. Rubin's proposal would have in Columbia's service territory, please refer to the Rebuttal Testimony of Toby Bishop on behalf of Columbia (Columbia Statement No. 17-R).

Thus, in the end, Columbia's ratepayers and the community are the ones who will unnecessarily suffer if Columbia does not receive the financial resources necessary to invest in its construction programs.

Overall, Mr. Rubin tries to have it both ways—by assuring us that he is not "suggesting that Columbia should have rates that are inadequate to ensure the provision of safe and reliable service to its customers"[33]—while simultaneously ensuring with his ratemaking proposal that Columbia will not receive reasonable and necessary revenues to fulfill its statutory and Commission-ordered obligations.

VI. FUNDAMENTAL PROBLEMS WITH MR. RUBIN'S METHOD

Q. DO YOU AGREE WITH MR. RUBIN THAT PUBLIC UTILITY RATES SHOULD BE ADJUSTED TO COINCIDE WITH THE ABILITY OF COLUMBIA'S CUSTOMERS TO PAY THEIR UTILITY BILLS WHEN THEIR INCOMES HAVE BEEN DIMINISHED BY CURRENT ECONOMIC CONDITIONS?

A. No, I do not agree. *First*, if Columbia's rates rose and fell in sync with changes in current economic conditions and the effects on some portion of Columbia's customer base, the resulting unpredictability of revenues would seriously handicap its management's financial and construction planning. Rates would frequently fluctuate (sometimes dramatically) depending on what was happening with the general economy. Sometimes Columbia would over earn and sometimes under earn. Sometimes its customers would overpay for service and sometimes under pay. Sometimes there would be sufficient revenues for Columbia to make needed improvements to ensure safety, and other times not.

Regulation exists to ensure that utilities always earn no more than a *fair* amount because they provide an essential service that is best achieved when the utility is financially

[33] OCA St. No. 1, p. 24.

stable. Such stability fosters desirable predictability by ratemaking that normalizes revenues and expenses and allows returns on investment for a period during which the utility is given an opportunity to earn a return at that level.

Second, allowing utility rates to "yo-yo" with the economy would jeopardize not only Columbia's financial stability but also its service reliability and safety. To ensure against such adversities, utility regulators are empowered to set the rates, terms, and conditions of service of privately owned utilities. To an extent, especially during the rate design phase of rate cases, rates are permissibly lowered with various programs for customers of lesser means by raising rates for others. Because government must protect all its citizens, such subsidization within reasonable bounds is entirely proper.

Patently impermissible and shortsighted, however, is reducing shareholder (or bondholder) returns below the otherwise appropriate level to subsidize customers of lesser means. If that occurs, investors raise the cost of capital to compensate for the increased risk of obtaining a fair return. If reducing returns is done in a substantial manner, confiscation occurs, and investors take their money elsewhere leaving the utility in ever more serious financial straits.

VII. OTHER SPECIFIC INFIRMITIES IN MR. RUBIN'S PROPOSED METHOD

Q. ARE THERE OTHER SPECIFIC INFIRMITIES IN MR. RUBIN'S PROPOSED METHOD?

A. Yes, there are at least five. *First*, Mr. Rubin's remedy is overly broad. Under his method, all customers, including most customers who remain employed and even the wealthy, would pay little or no rate increase. This result makes no sense and demonstrates that his relief is too broad.

Mr. Rubin's methodology would deny Columbia the opportunity to recover its increased cost of service from the significant number of its customers that have not experienced a loss of income as a result of the pandemic.

Nor has Mr. Rubin demonstrated that the government and Columbia assistance provided to those who have lost some or all their income is insufficient to pay the proposed increase. Moreover, if it is insufficient, the appropriate remedy is for the Commonwealth and Columbia to adjust such programs, not to deny an increase to customers who can afford to pay it (I elaborate on this below in the last section of my testimony).

Second, Mr. Rubin provides no analysis of the actual impact of the proposed rate increase on the customers whom he claims are too harmed by the pandemic to pay any increase in Columbia's rates. Nor does he demonstrate that Columbia's customer assistance programs have failed to resolve those issues.

Third, he essentially ignores substantial government aid provided in response to the COVID-19 pandemic in determining whether the increase requested is affordable or not.

Fourth, Mr. Rubin's approach must fail for lack of adequate standards. How large must the proposed rate increase be before it becomes unaffordable? For what percentage of the customer base? When and to what extent are economic conditions sufficiently debilitating as to justify the prohibition of rate increases? Under what conditions is normalcy restored? Mr. Rubin's testimony provides no standards to decide these and other pertinent questions. Based as the variability of the economy, his proposed ratemaking by polls and surveys would result in unpredictable, perhaps wildly fluctuating rates.

What is predictable is that such a system would be unacceptable to the investors that have historically provided capital to Pennsylvania utilities with the result that capital will become more expensive and potentially not available in difficult economic conditions.

Fifth, his proposal is fundamentally asymmetric. Mr. Rubin proposes a ratemaking method that would produce rates below the traditional zone of reasonableness during an economic disruption, but it undoubtedly would not produce rates above the zone of reasonableness in good economic times.

Unregulated businesses' earnings, during good financial times, are not constrained. Regulated businesses, such as Columbia's, are fundamentally different in this respect. Utility profits are constrained at both ends of the equation—they may not be too high or too low.

Furthermore, unregulated businesses can generally enter and exit markets at their discretion and seek to serve markets where they can earn higher profits and refuse to serve low profit markets altogether. Columbia cannot do this. It must serve all customers in its service territory, and it must provide safe and reliable service throughout its service area. For these reasons, its rates are regulated and its earnings protected on the low end by confiscation standards and constrained on the high end by its regulators.

Q. MR. RUBIN AT PAGES 8-9 OF HIS TESTIMONY CITES HIS PREVIOUS TESTIMONY IN *COLONY WATER SYSTEM, LTD.*, DOCKET NO. R-00922375,[34] REGARDING "JUST AND REASONABLE" RATES AND THE "ZONE OF REASONABLENESS". DOES HIS TESTIMONY IN THIS CASE DIFFER FROM HIS EARLIER TESTIMONY?

A. Yes, it differs in an important regard although it substantially mirrors his earlier testimony. Rather than recommending (as he does here) complete denial of the utility's rate increase request that allegedly would make service unaffordable to some customers, Mr. Rubin in

[34] *Pennsylvania Public Utility Commission, Paul Maden, James A. Dimperio v. Colony Water Systems, Ltd.*, Docket No. R-00922375, Order entered June 10, 1993 (attached to my testimony as Exhibit JHC-2).

Colony Water advocated a different ratemaking approach to proposed rates that were (in his view) "above the range of reasonableness from the consumers' perspective; particularly the perspective of low-income consumers"[35] and he elaborated on his theory of a "null" zone of reasonableness. In doing so, however, he substantially agrees with my testimony in this case regarding the proper responses to rates that cause difficulty to some customers.

Specifically, I believe his *Colony Water* testimony is consistent with my view that needed revenue increases should be responsibly granted, and that customers who cannot afford the increase should be helped with all available financial assistance. His earlier testimony gives an example of electric rates "which are unaffordable for some segments of the population." In response to such rates, he describes the same types of help that I recommend when rates must be set at a level that causes payment problems for some customers: "Some responses to that problem have been energy assistance funds, customer assistance programs, lifeline rates, and the like which effectively reduce rates for low-income consumers so that they lie within their range of affordable rates."[36] These responses are more appropriate and responsible than complete denial of the requested increase.

Q. IS THERE SUCH A THING AS A "NULL" ZONE LOWER THAN THE LOWEST REASONABLE RATE WITHIN THE TRADITIONAL ZONE OF REASONABLENESS?

A. No. A rate, or a return on investment, is either reasonable—i.e., neither confiscatory of the utility's property nor exploitive of customers, or it is unreasonable—i.e., it is confiscatory

[35] *Id*., p. 10 of his testimony.

[36] *Id*.

or exploitive. A "null" rate or return on investment falling below the lowest reasonable rate within the traditional zone of reasonableness is confiscatory.

Q. MR. RUBIN RECOMMENDS THAT THE COMMISSION "ACT WITHIN THE BROAD PUBLIC INTEREST." DOES THAT MEAN THAT CUSTOMERS' INTERESTS CAN BE FAVORED OVER INVESTORS' INTERESTS TO DETERMINE JUST AND REASONABLE RATES IN TIMES OF ECONOMIC DISTRESS?

A. No, that is not what "acting in the broad public interest" means. Favoring customers' interests (or investors' interests) would be a distortion of the most accepted principle of utility ratemaking announced in the famous *Hope* decision by the U.S. Supreme Court:[37] rates are defined to be just and reasonable if they *balance* consumer and investor interests. The public interest is determined by a balancing of the interests without favoring either of them. It is an amalgam of both as determined by the discretion of the Commission.

Mr. Rubin acknowledges that principle[38] but wrongly applies it by changing what he perceives as bias favoring investors' interests to bias favoring customers' interests. Thus, he advocates that, because the pandemic adversely affects some customers, no just and reasonable rate beyond existing rates is possible or justified. This, of course, is not the required balancing of interests but improper unbalancing of interests.

Here, it is especially important for the Commission to take not only a broad view of the public interest but a long one as well because utilities provide essential services that require ongoing investment supported by regular and rational rate relief, especially to put in place costly long-lived infrastructure made possible by indispensable private investors. More than most Pennsylvania utilities, Columbia is in need of such a long view because of

[37] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

[38] OCA St. No. 1, p. 5 ("In setting rates, regulators should attempt to balance the interests of all relevant sectors of the public.").

its initiative to commence aggressive replacement of bare steel, wrought iron, and cast iron pipe in 2007[39] and its continuing commitments to do so as evidenced by its First and Second Commission-approved Long Term Infrastructure Improvement Plans.[40]

Q. TO SET COLUMBIA'S RATES, SHOULD THE COMMISSION MIRROR COMPETITIVE MARKET FORCES?

A. No. Competitive market pricing is incompatible with regulation of natural monopolies like public and municipal utilities because, unlike competitive enterprises, they are not free to charge what the market will bear. As I noted previously, utilities are limited to no more than a fair return in good times and bad because their service is "affected with the public interest." Because their service is essential to the public's health, safety, and convenience, they are intentionally insulated from the boom and bust cycles characteristic of highly competitive enterprises that can achieve very high returns. Utilities are therefore protected from some of the downside risks of the business. As I state below regarding the asymmetry of Mr. Rubin's recommendations, in return for that protection, the utility surrenders the upside opportunity to make large economic profits were it to be an exceptionally brilliant or lucky performer.

In the end, the "competitive forces" suggestion is an exercise in circular reasoning: because competitive markets cannot work as intended where monopoly service is provided, rate regulation is necessary, but in setting rates, every effort should be made to mirror the outcome of a competitive market.

Consequently, Mr. Rubin errs in arguing that "regulation is supposed to be a substitute for market forces, … competitive businesses cannot sustainably raise prices

[39] Columbia St. No. 14, p. 3.

[40] P-2012-2338282(filed December 7, 2012 and approved March 14,2013) and P-2017-2602917.

when their customers' incomes have decreased significantly."[41] Columbia is not a competitive business because, in Mr. Rubin's words, "it would be economically inefficient (more expensive) to have competing enterprises provide the service."[42]

Q. MR. RUBIN CITES REGULATORY PRECEDENTS, PAST AND PRESENT, REGARDING RATEMAKING DURING A PANDEMIC. ARE YOU AWARE OF STATE REGULATORY COMMISSIONS DEFERRING DECISIONS AND SUPPRESSING RATES BECAUSE OF ECONOMIC DISLOCATIONS?

A. Like Mr. Rubin, I have not conducted exhaustive research to try to identify every regulatory and utility response to rate setting during the pandemic. I am not impressed, however, by the seven current American and two Canadian examples he cites.[43] There surely are dozens of rate cases in the United States that have been decided or are underway because of the pressing need to sustain essential public utility services despite the adverse effects of the pandemic. Under the best of circumstances, other state commissions' decisions are of limited precedential value because of differing laws and regulatory rules in those states and the uniqueness of every utility's financial makeup, climate, customer mix, management structure and ability, and the like.

Without intending to offer a legal opinion but merely to state facts obvious to any observer, I am equally unimpressed by Mr. Rubin's citation of *Donham v. Public Service Commission*, 232 Mass. 309, 122 N.E. 397 (1919),[44] or his reliance on that case's quotation from *Missouri, Kansas & Topeka Railway Co. v. Interstate Commerce Commission*, 164 Fed. 645, 648 (1908) (confirming the settled principles that investors' and customers' interests must be balanced, and that a utility bears the burden of failing to achieve its

[41] OCA St. No. 1, p. 9.

[42] *Id*., p. 4.

[43] *Id*., pp. 21-22.

[44] *Id*., pp. 19-20.

allowed return if it operates imprudently or inefficiently).

Donham itself is a lonesome and factually inapt precedent for making a valid public policy recommendation for the present pandemic circumstances. The court cited six reasons for the streetcar company's dire financial straits, listing "the wide prevalence of the epidemic known as influenza, a factor seriously affecting receipts [only] during October and November, 1918."[45] The first five reasons were "(1) Heavy increase in wages likely to absorb sixty-five to seventy per cent of yearly receipts on present basis; (2) great increase in cost of steel, coal, copper and other materials necessary for operation; (3) offset of increase in fares by loss of traffic; (4) the adverse conditions of poor equipment; (5) lack of profit on many country lines."[46] The Massachusetts Public Service Commission's underlying decision stated, "It is clear that the chief factor in the present unfortunate plight of this company is the recent extraordinary rise in wages and prices, rather than any of these things. … The problem is … meeting the necessary and unavoidable cost of furnishing the service."[47] In short, the economic effects of the influenza epidemic had little to do with the Commission's decision, while the court's decision primarily concerned the propriety of the rates proposed by the receiver of the streetcar company's parent company versus the trial period rates set by the Commission.

[45] 122 N.E. at 400.

[46] *Id*.

[47] *Id*., 122 N.E. at 401.

VII. PROPER STATUTORY RATEMAKING

Q. WHAT ARE THE FUNDAMENTAL PRINCIPLES OF COST-OF-SERVICE UTILITY RATEMAKING?

A. The most fundamental principle of base ratemaking is that rates should be set so that a utility has a reasonable opportunity to recover the costs prudently incurred in providing service. The equation: RR = E + ROR (RB) summarizes this principle. The revenue requirement (RR) of a utility equals the expenses (E) incurred, including wages and employee benefits, state and federal taxes and depreciation, plus a return on investment (ROR x RB). The return on investment is calculated by multiplying the overall cost of capital to the company (rate of return or ROR) against the net assets dedicated to the public use (rate base or RB).[48]

The revenue requirement represents the total revenue that a utility needs to collect through the rates charged to the public to cover its cost of service. This is the central issue in a base rate case: identifying the cost of service or revenue requirements of the company.

Q. WHAT OCCURS ONCE THE REVENUE REQUIREMENT HAS BEEN DETERMINED?

A. Once Columbia's revenue requirement has been determined, the final step is the translation of the overall increase into tariffs (replacing those initially filed to produce the proposed rate increase), a process called "rate design" or determining the "rate structure." Once the size of the "pie" is determined in the revenue requirement process, there is a fair apportionment of the utility's total revenue requirement to each rate class or schedule through four main steps:

[48] *See* Cawley & Kennard Guide, pp. 102-138.

- Direct Assignment – assignment to a rate class of any costs that clearly are caused (incurred by or for only that rate class.
- Functionalization – the arrangement of costs according to major functions using the Uniform System of Accounts, e.g., production, transmission, and distribution.
- Classification – the further division of costs into groups bearing a relationship to a measurable cost-defining service characteristic, e.g., metered natural gas use in thousands of cubic feet or dekatherms.
- Allocation – the apportionment of joint costs among two or more rate classes in accordance with each class's relative share of a measurable cost-defining service characteristic.

Beyond the basic concern of allowing Columbia the opportunity to recover the allowed revenue increase, there are a variety of other factors to be considered: the cost of service by rate class, value of service, gradualism (meaning rates should not be raised too abruptly), policy objectives (e.g., conservation), and social welfare considerations.[49] But these factors go to how the "pie" is to be sliced; not the size of the pie in the first place.

Other examples of relevant factors include the utility's recent and past rate history and rate programs of the utility, the sales characteristics of the various classes of consumers, the practicability of administering the schedules, the value of the service to the various consumers, the promotional aspects of the rates, and the competition in certain areas by other fuels.[50]

[49] *See* Cawley & Kennard Guide, pp. 138-155.

[50] *City of Pittsburgh v. Pa. Pub. Util. Comm'n*, 126 A.2d 777, 785-86 (Pa. Super. 1956).

More pertinent to our present economic circumstances, rate structures may be modified from time to time in response to changes in economic conditions, whether general changes or changes especially affecting particular classes of customers.[51] Adjustments should not be made for temporary economic fluctuations.[52]

Q. ARE YOU SUGGESTING THAT THE COVID-19 PANDEMIC IS A TEMPORARY ECONOMIC FLUCTUATION?

A. Whether the current pandemic remains serious for customers when Columbia's proposed rates are scheduled to go into effect remains to be seen, but that will be reflected in the level of Columbia's arrearages, uncollectible accounts expense, and most importantly, participation rates in Columbia's customer assistance programs and initiatives that may become the subject of future proceedings. Meanwhile, the parties to this case should focus on the reasonableness of Columbia's FPFTY projections.

Q. WHY DO YOU SUGGEST SUCH A FOCUS?

A. Sound and accepted utility ratemaking should not be deterred by unsettling economic circumstances because Columbia's obligation to provide *essential* safe, adequate, and reliable service at reasonable rates is not suspended during such times. Columbia's need to recover its operating expenses and attract capital does not disappear during difficult economic straits.

Mr. Rubin's advocacy urging complete regulatory distrust and rejection of Columbia's claims because of the uncertainty of existing or anticipated economic conditions is not sound public policy. No one has a crystal ball, but ratemaking is prospective and must occur somehow because, again, Columbia provides an *essential*

[51] *U.S. Steel Corp. v. Pa. Pub. Util. Comm'n*, 390 A.2d 865, 871 (Pa. Cmwlth. 1978).

[52] *City of Pittsburgh v. Pa. Pub. Util. Comm'n*, 144 A.2d 648, 660 (1958).

public service. That "somehow" is facilitated using test year data and projections of revenue and expenses as reasonably as they can be determined, which is a process authorized by Pennsylvania's General Assembly.[53]

Because Columbia's service is essential to the public's health, welfare, and safety in good times and in bad, the Commission and its counterparts across the nation use the test year method to provide reasonable rate certainty during the period when the rates will be in effect.[54] The use of a test year is a sound and reasonable basis for establishing a representative level of prospective rates. It allows for a reasonable measure of predictability and semi-permanence in ratemaking.

The test year concept is such a basic tenet of ratemaking that the use of a fully projected future test year ("the twelve month period beginning with the first month that the new rates will be placed in effect after application of the full suspension period") was recognized by the General Assembly under Act 11 of 2012 and is now embodied in Section 315(e) of the Public Utility Code.

Q. HOW DOES THIS BEAR ON THE PROPRIETY OF MR. RUBIN'S PROPOSED METHOD OF RATEMAKING?

A. His method is the antithesis of accepted ratemaking principles because it is based on abnormal, extraordinary conditions, while the test year concept rejects abnormal distortions and reflects typical conditions (which guards against, at any given time, the utility either receiving too much or too little, and customers either paying too much or too little).

[53] *See* Public Utility Code Section 315(e) (relating to burden of proof; use of future test year), 66 Pa.C.S. § 315(e).

[54] *See* Cawley & Kennard Guide, pp. 85-88.

In short, Mr. Rubin's advocacy of abnormal ratemaking and rejection of all fully projected test year costs in abnormal times is fundamentally inconsistent with fully forecasted test year ratemaking.

VIII. <u>THE CONFISCATORY RISK OF CHANGING RATEMAKING METHODOLOGIES</u>

Q. IS THERE A RISK OF CONFISCATION BY ADOPTING MR. RUBIN'S AFFORDABILITY MODEL?

A. Yes, there is a significant risk of confiscation which Mr. Rubin acknowledges but then ignores with his affordability model. He correctly acknowledges that "[i]n protecting consumers, regulators cannot confiscate the property of the utility's investors. That is, regulators cannot tilt the scale so far in favor of consumers … that the utility's investors are deprived of an opportunity to earn a reasonable return on their investment."[55]

I can speak to this risk from my experience as a commissioner. I voted to allow recovery from customers of nuclear power plant cancellation costs (thinking that it encouraged early, prudent cancellation rather than imprudent continuation and much greater costs needing recovery later). The case on appeal was ultimately decided by the U.S. Supreme Court's most recent decision regarding public utility ratemaking.[56] Affirming the disallowance of the cancellation costs contrary to my vote, the Court recognized that ratemaking can be confiscatory if there is an arbitrary change in methodology.

As described by the Court, "a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad

[55] OCA St. No. 1, p. 4.

[56] *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989).

investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions."[57]

Mr. Rubin's suggested switch from traditional to "affordability" ratemaking is just such an arbitrary change of ratemaking methodology. In fact, his proposal is even more arbitrary. Rather than making investors bear only the risks of bad investments while denying them the benefit of good ones, his method gives Columbia no opportunity to prove its case, which (without meaning to offer a legal opinion) surely has grave constitutional implications. That is playing a regulatory game of heads-the-customer-wins, tails-Columbia-loses.

IX. <u>BETTER ALTERNATIVES TO MR. RUBIN'S METHOD AND RECOMMENDATION</u>

Q. WHAT DO YOU RECOMMEND AS ALTERNATIVES TO MR. RUBIN'S PROPOSED METHOD AND RECOMMENDATION?

A. My recommendation is that the Commission, once again, responsibly grant Columbia needed revenue increases so that it may continue its remarkable main replacement achievements, and that customers who cannot afford the increase should be helped with all available financial assistance, i.e., customer assistance programs like those Columbia maintains in its Commission-approved Universal Service and Energy Conservation Plan ("USECP"). Please also refer to the Rebuttal Testimony of Columbia witness Andrew S. Tubbs (Columbia St. No.1-R) and of Columbia witness Deborah Davis (Columbia St. No. 13-R).

In closing, I specifically note Columbia's efforts to provide additional relief in response to the COVID-19 pandemic. On April 24, 2020, Columbia filed a petition seeking

[57] *Id*., 488 U.S. at 315.

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.[58]

Columbia designed the proposed Reduced Income Grant Program ("RIGP") as a one-time grant to offer financial assistance to customers who found themselves in difficulty but did not qualify for Columbia's CAP or the Hardship Fund.

The Commission had certain concerns about the effect on the Hardship Fund and therefore denied the petition by Order entered on July 16, 2020.

Nevertheless, when I was a member of the Commission, I was always attuned to whether a utility's management demonstrated sensitivity to the needs of the utility's customers. It counted (one way or the other) when I voted on rate cases. Columbia's petition demonstrates sensitivity to its customers. Although it was not approved, Columbia should be given credit for trying, and for its outstanding leadership in main replacements since 2007.

X. CONCLUSION

Q. DOES THAT COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes. I reserve the right to supplement this testimony as may be appropriate.

[58] *Petition of Columbia Gas of Pennsylvania, Inc. for Expedited Approval to Use a Portion of the Residential Pipeline Penalty Credit and Refund Proceeds as Funding for a Temporary Program that Provides Grants to Residential Customers Experiencing a Reduction of Income Due to the COVID-19 Pandemic,* Docket No. P-2020-3019578 (filed April 24, 2020).

COMMONWEALTH OF PENNSYLVANIA

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August 24, 2020

Via Electronic Mail Only
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Re: Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2020-3018835

Dear Counsel:

Enclosed please find the Office of Consumer Advocate's Responses to Columbia Gas of Pennsylvania, Inc.'s Interrogatories, Set II, in the above-referenced proceeding.

Copies of the responses have been served as indicated on the enclosed Certificate of Service.

Respectfully submitted,

/s/ Laura J. Antinucci
Laura J. Antinucci
Assistant Consumer Advocate
PA Attorney I.D. # 327217
E-Mail: LAntinucci@paoca.org

Enclosures:
cc: PUC Secretary Rosemary Chiavetta, (Letter and Certificate of Service only)
Certificate of Service
*294544

CERTIFICATE OF SERVICE

Re: Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	:	

I hereby certify that I have this day served a true copy of the following document, the Office of Consumer Advocate's Responses to Columbia Gas of Pennsylvania, Inc., Set II, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

Dated this 24th day of August 2020.

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Dated: August 24, 2020
*294545

Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2020-3018835

Responses of the Office of Consumer Advocate
to Columbia Gas of Pennsylvania, Inc.
Set II

CGP-OCA-II-1 On page 3, lines 10 through 14, of OCA Statement No. 4 (the Direct Testimony of Jerome D. Mierzwa), Mr. Mierzwa states as follows: "In addition, as a result of the COVID-19 pandemic, it would not be just or reasonable to impose a rate increase at this time when unemployment numbers are close to record-highs and the economic effects of the pandemic will not be fully known for some time. Therefore, the Commission should deny any rate increase in this proceeding."

a. Please have Mr. Mierzwa define his understanding of the term "just and reasonable" as it relates to establishing rates for a public utility company.

b. Has Mr. Mierzwa offered testimony in other proceedings regarding whether a public utility company's requested rate increase is "just and reasonable?"

c. If the answer to part b of this question is in the affirmative, please provide copies of the ten (10) most recent testimonies and provide page references to the portions of testimony that address "just and reasonable" rates.

RESPONSE:

a. The referenced lines of testimony are from a paragraph included in Mr. Mierzwa's testimony that starts at line 6 and extends to line 14. As indicated in the first sentence of the paragraph, Mr. Mierzwa is referencing the testimony of Mr. Scott J. Rubin in OCA Statement No. 1, and the entire paragraph identified positions taken by Mr. Rubin. (See page 27, lines 13-22 of Mr. Rubin's testimony). Mr. Mierzwa's testimony does not address the position is taken by Mr. Rubin which are included in the referenced paragraph.

b. Mr. Mierzwa has presented testimony in over 350 proceedings. To the best of Mr. Mierzwa's recollection, Mr. Mierzwa has not presented testimony addressing whether a public utility company's requested rate increase is "just and reasonable."

c. See the response to subpart (b).

Response prepared by: Jerome D. Mierzwa

Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2020-3018835

Responses of the Office of Consumer Advocate
to Columbia Gas of Pennsylvania, Inc.
Set II

CGP-OCA-II-2 On page 3, lines 10 through 14, of OCA Statement No. 4 (the Direct Testimony of Jerome D. Mierzwa), Mr. Mierzwa states as follows: "In addition, as a result of the COVID-19 pandemic, it would not be just or reasonable to impose a rate increase at this time when unemployment numbers are close to record-highs and the economic effects of the pandemic will not be fully known for some time. Therefore, the Commission should deny any rate increase in this proceeding."

a. Is it Mr. Mierzwa's position that a public utility company should be denied a rate increase if "unemployment numbers are close to record-highs?"

b. Is it Mr. Mierzwa's position that Columbia Gas of Pennsylvania, Inc. should be denied a rate increase, without consideration of the company's rate case filing, because the "unemployment numbers are close to record-highs?"

RESPONSE:

a. (Same general response as OCA-II-1(a).

b. Mr. Mierzwa's testimony does not address whether Columbia Gas of Pennsylvania, Inc. should be denied a rate increase because unemployment numbers are close to record highs.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018835
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that I am the witness responsible for responding to Columbia Gas of Pennsylvania, Inc.'s Interrogatories directed to the Office of the Consumer Advocate, Set II, and that the facts above set forth are true and correct to the best of my knowledge, information and belief in the interrogatory responses. 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: August 24, 2020
*294541

Signature: Jerome D. Mierzwa

Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.
A. My name is Scott Rubin. I am an attorney, employed by the Pennsylvania Office of Consumer Advocate as a Senior Assistant Consumer Advocate. My business address is 1425 Strawberry Square, Harrisburg, PA 17120.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?
A. My testimony will propose a method of setting rates for Colony Water System, Ltd. (Colony) which I believe to be fair to both Colony and its customers.

Q. WHAT ARE YOUR QUALIFICATIONS TO TESTIFY ON THESE ISSUES?
A. I have been employed by the Office of Consumer Advocate (OCA) since 1983 in increasingly responsible positions. I have become expert in matters relating to the economic regulation of public utilities, particularly water and electric utilities. I have published articles and authored speeches and other presentations, on both the national and state level, relating to regulatory issues. Since 1990, I have been one of two senior attorneys with the OCA. Among my other responsibilities in this position, I have a major role in setting the OCA's policy positions on water and electric matters. I have testified on public policy and rate design issues before this Commission on three other occasions. Appendix A to this testimony is my curriculum vitae.

Q.PLEASE DESCRIBE COLONY WATER SYSTEM.

A.Colony is a small, privately owned water system which serves approximately 35 customers. It is located in Fairview Township, Erie County and purchases all of its water from the Fairview Township Water Authority (FTWA). While Colony once had its own well, it no longer has its own source of water supply. In essence, then, Colony is a reseller and distributor of water; it purchases from FTWA at wholesale and resells the water to Colony's customers at retail.

Even though Fairview's rates are metered, Colony does not meter its customers. At present, each Colony customer pays a flat rate of $37.50 per quarter. Under Colony's proposal, that rate would nearly <u>quintuple</u> to $181.72 per quarter, or more than $725 per year.

Q.WHY DOES IT COST SO MUCH FOR COLONY TO SERVE ITS CUSTOMERS?

A.With the exception of less than $1500 per year for testing and maintenance, Colony's only expenses consist of purchased water, administration, and depreciation. It has no production expenses. In fact, its only claimed rate base is the interconnection with FTWA; Colony states that all of the distribution system is fully depreciated.

On Schedule 1, attached to this testimony, I have summarized Colony's claimed cost of service. I also calculate the cost per customer for each category of costs. As that Schedule shows, the cost to Colony of actually supplying the water to its customers is only $218 per customer per year. The bulk of this cost ($176 per customer) is purchased water expense. Significantly, the remaining $510 per customer which Colony claims is comprised of administrative expenses ($185 per customer) and return of ($43) and return on ($282) Colony's investment in the interconnection with FTWA.

Q. IN YOUR OPINION, IS IT REASONABLE FOR COLONY'S CUSTOMERS TO HAVE TO BEAR COSTS OF THIS MAGNITUDE?

A. No, it is not. There is no valid reason why the customers of a water utility should have to pay $185 each to administer a utility and $325 each to cover the costs of invested capital. It must be remembered that Colony is a reseller of water; that is, a middle man. Where the costs to resell the water are more than twice the costs of actually purchasing the water, I believe that the middle man must find a way to greatly reduce its costs. If it cannot do so, then I do not believe it to be in the public interest for the middle man to remain in business.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission set Colony's rates equal to the rates which Colony's customers would pay if they were direct customers of FTWA. On Schedule 2, I provide a calculation of the bill for Colony's customers under FTWA's rates. I would note that, because Colony is not metered, I could not simply apply FTWA's rates to the individual usage of Colony's customers. My Schedule, therefore, is based on the following assumptions:

1. That Colony will purchase 776,000 gallons per quarter from FTWA (Colony Exh. 1, page 8).
2. That all of this water should be charged to Colony's customers. This means that I am assuming that Colony has _no_ lost or unaccounted for water.

The result of this calculation is that Colony's flat rate for its customers would be set at $84.22 per quarter ($336.88 per year). This represents a 125 percent increase over Colony's existing rates.

Q. WHAT IS THE EFFECT ON COLONY OF SETTING RATES AT THIS LEVEL?

A. On Schedule 3, I have summarized the effect of my recommendation. It can be seen from that Schedule that Colony would be able to cover all of its supply and depreciation expenses and an additional $2,672 per year ($76 per customer). It would then be up to Colony to determine whether it can remain in business for that additional $2,672 per year.

Q. IS THERE ANY PRECEDENT FOR THIS TYPE OF RECOMMENDATION?

A. This situation is closely analogous to unregulated resellers of utility services. For example, there are numerous apartment complexes, condominium developments, office buildings, and similar businesses which purchase utility services at wholesale and resell those service to tenants or owners at retail. Under Section 1313 of the Public Utility Code, such a resale is permitted if the retail rate charged is no more than the retail rate which the tenant/owner would pay as a direct retail customer of the utility. The theory is that the end user is protected from having to pay more than it would pay as a direct customer of the public utility; and the business is protected by receiving some margin above its costs to cover the costs of administration and maintenance.

Similarly, under Sections 63.111 to 63.118 of the Commission's Regulations, resellers of intrastate telecommunications services are generally permitted to charge no more than the customer would be charged under the tariff of any public utility providing a comparable service.

While these provisions are not directly applicable to this case, I believe that the same principles apply here. The best way to protect the customers of Colony (the reseller) is to ensure that they pay no more than they would have to pay as direct customers of FTWA. If the reseller cannot recover its costs at those rates, then it is not in the public interest for the reseller to provide the service. Stated differently, it is only reasonable for the reseller to act as a middle man if it can provide the service at a rate which is no more than the rate charged for the same service by the initial supplier.

Q. YOUR RECOMMENDATION WOULD RESULT IN COLONY'S RATES BEING SET AT WELL BELOW ITS COST OF SERVICE. CAN YOU EXPLAIN WHY, IN YOUR OPINION, IT IS SOUND PUBLIC POLICY FOR THE COMMISSION TO DO THIS. LET ME EMPHASIZE THAT I AM NOT ASKING YOU FOR A LEGAL OPINION, BUT FOR YOUR OPINION AS A PUBLIC POLICY EXPERT.

A. With that understanding, I will attempt to provide you with an overview of the relevant policy considerations. I will leave it to trial counsel to discuss the Commission's legal authority to do what I believe it should do as a matter of public policy. I begin with the premise that when it sets rates, the Commission should attempt to balance the interests of all relevant sectors of the public. This includes the utility's investors, the utility's officers and employees, the customers (recognizing that different customer classes also have different interests), and local governments whose residents are served by the utility. Ideally, rates should be set within a "zone of reasonableness" which represents a range within which all of the relevant interests intersect. To help explain the concept, I have provided Figure 1 which illustrates this zone of reasonableness as a simplified diagram, showing just consumers as a whole and investors.

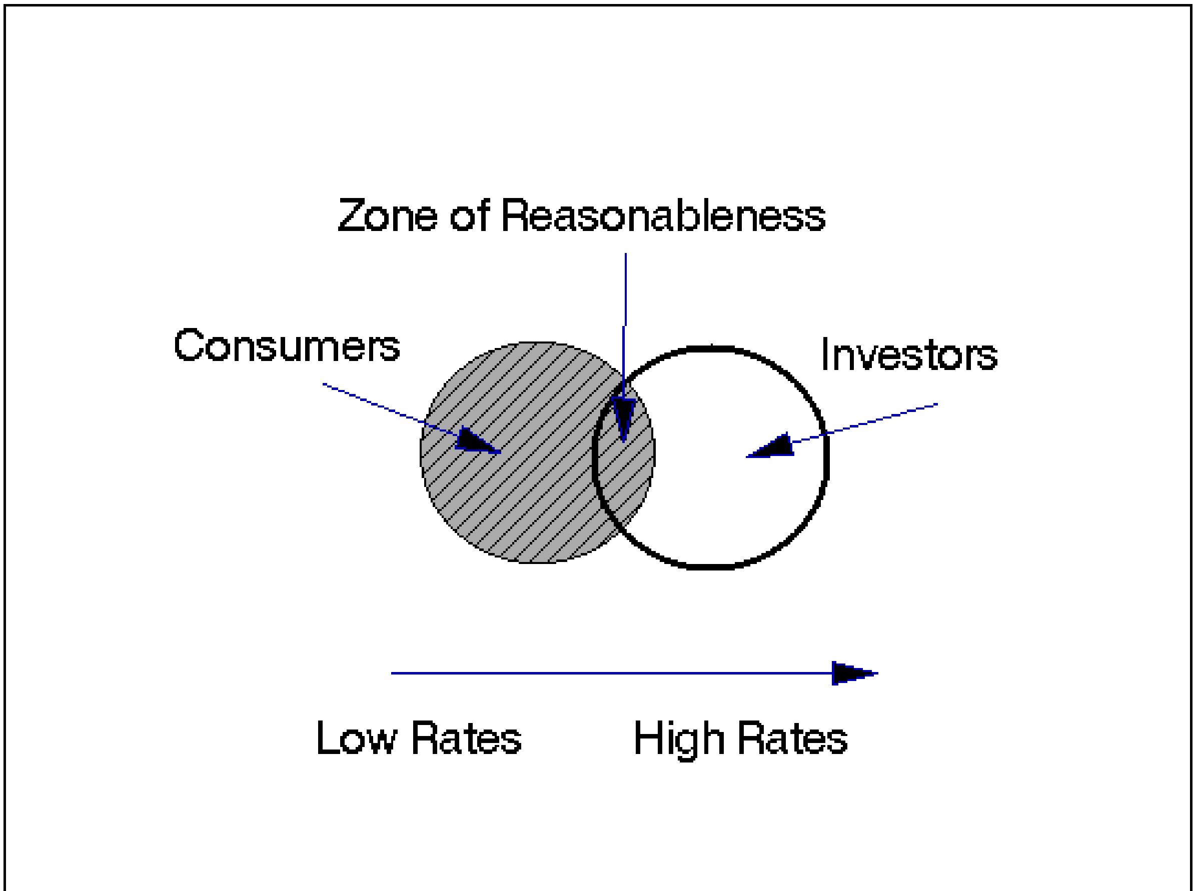

Figure 1: Traditional Zone of Reasonableness

In this example, which illustrates the situation in which rate regulators usually find themselves, there is an overlap between the interests of consumers and investors. That is, there is a range of rates that consumers are willing and able to pay (ranging from zero at the low end to a rate which is so high that they can no longer afford utility service) and a range of rates which will provide investors with what they consider to be a reasonable return on their investment (presumably ranging from something more than the risk-free rate of return up to a return well above that which the market provides to similar-risk investments). In this illustration, these two ranges overlap. This provides the Commission with a range within which it can set rates that still meet the needs of both consumers and investors. The size and relative position of the range may change, but we are used to having at least a partial convergence of these ranges.

However, it is possible that, for a variety of reasons, the interests of investors and consumers might diverge. This divergence is illustrated in Figure 2.

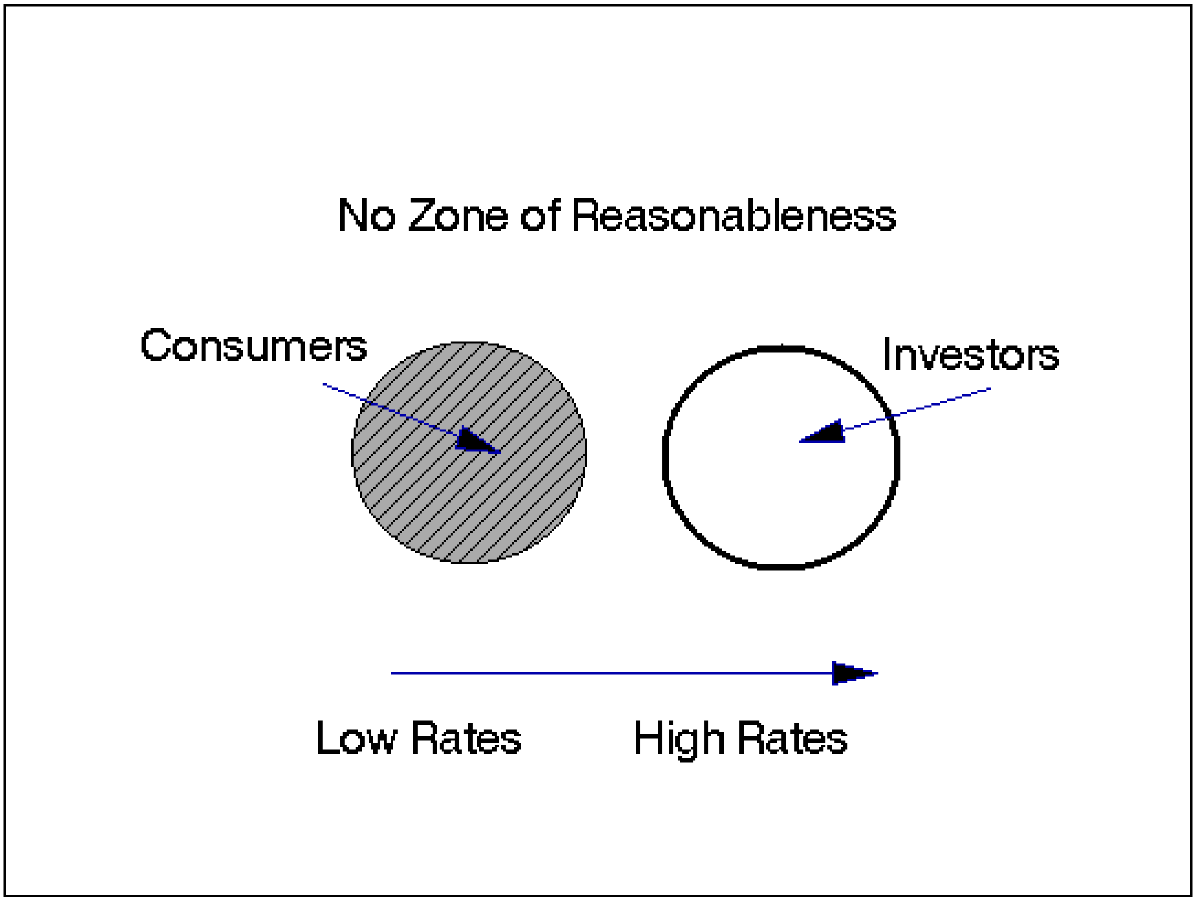

Figure 2: Divergent Interests -- A Null Zone of Reasonableness

For example, if a utility is providing poor service (or a service which is becoming obsolete), the highest price which consumers are willing to pay may be very small, thereby falling below the low end of the investors' range. Similarly, if interest rates or the levels of investment become very high, investors' minimum return requirements may become so high as to fall above the range of rates which consumers can afford to pay. When this happens, the rate regulators may have to set rates which fall outside of the normal zone of reasonableness, but which still attempt to fairly balance the interests of all parties to the extent possible.

It also must be remembered that while these concepts can be easily illustrated using circles on a diagram, the real world is not so simple. There is no bright line delineating any of these interests. The Commission is forced to discern the relative interests of the parties from the arguments and evidence which is placed on the record.

Q. HAVE THERE BEEN INSTANCES WHERE IT APPEARS THAT RATES WERE SET WHERE THERE WAS NO "ZONE OF REASONABLENESS"?

A. As I said, it's very hard to tell whether or not that is actually happening. It is possible, though, that this was the case for several electric utilities which had massive increases in their investment, leading investors' return requirements to become very high. I think that in some instances that led rate regulators to set rates which were above the range of reasonableness from the consumers' perspective; particularly the perspective of low-income consumers. This has resulted in electric rates which are unaffordable for some segments of the population. Some responses to that problem have been energy assistance funds, customer assistance programs, lifeline rates, and the like which effectively reduce rates for low-income consumers so that they lie within their range of affordable rates. On the other end of the spectrum, when rate regulators have denied or greatly reduced rate increases (for example, because of poor quality of service, imprudence, or excess capacity), this may have resulted in rates which were insufficient to meet investors' expectations. The result of such actions may be a reduction in the utility's dividend payment, a down-grading of the utility's securities, or even bankruptcy.

Q. ARE YOU SAYING THAT THE COMMISSION SHOULD NOT SET RATES OUTSIDE THE ZONE OF REASONABLENESS?

A. No, I am not saying that. In fact, in certain instances it may be impossible for the Commission to simultaneously satisfy all aspects of the public interest. As I view the role of rate regulators, they must act within the broad public interest. Sometimes, that may mean setting rates which fail to meet the needs of a certain segment of the public. However, I believe that whenever it sets rates, the Commission must attempt to determine whose needs are being met and whose are not.

Q. ISN'T THAT USUALLY DONE IN THE TRADITIONAL RATEMAKING PROCESS?

A. Unfortunately, it is not usually done. In most cases, the investors' interest becomes a central focus of the case, by attempting to determine the return on capital which investors require in order to continue to invest money in the utility. This is usually examined in great detail, with each side spending thousands of dollars on attorneys and expert witnesses skilled in the presentation of this subject. Very rarely, though, do commissions or parties place as much emphasis on attempting to define the consumers' interest. While consumers are often represented in rate cases by offices such as mine, we tend to concentrate on attempting to redefine the utility's interest, rather than on affirmatively defining the consumers' interest.

Q. CAN YOU GIVE US AN EXAMPLE OF HOW THE CONSUMERS' INTEREST MIGHT BE IDENTIFIED?

A. There are several ways in which this could happen. One of them, which is becoming more common, is to closely examine the quality of service which consumers are receiving. The range of rates which consumers are willing to pay will be affected by their perceptions of the value of the service which they receive. For example, if a water consumer must purchase bottled water for drinking, the consumer will be willing to pay less to the water utility for water service.

Q. HOW DOES YOUR RECOMMENDATION REFLECT A BALANCING OF THESE INTERESTS?

A. My recommendation begins by focusing on the consumers' interest. In the case of Colony, consumers are receiving water produced by FTWA, passing through a middle man (Colony). It also must be remembered that these consumers are also residents of Fairview Township who should be entitled to the same type of water service as other township residents. Stated differently, these township residents receive township water, but it passes through a few hundred yards of pipe owned by Colony. I believe that the interests of consumers would be served by charging these customers no more than other township residents pay for FTWA water.

From the utility's perspective, my recommendation would immediately provide Colony with enough revenue to recover the direct cost of purchasing and distributing the water. It also would provide an additional margin above that to cover some administrative expenses and/or profit. If FTWA's rates increase in the future, I am proposing below a simplified ratemaking mechanism which would permit Colony to increase its rates at minimal expense. As a reseller, I do not believe that it is in the public interest for Colony to charge customers more than they would pay as retail customers of FTWA.

Finally, I would reiterate that my recommendation results in a 125% rate increase. I do not propose an increase of this magnitude lightly. I believe, though, that this large of an increase is necessary at the present time in order to fairly balance the interests of Colony and its customers.

Q.UNDER YOUR RECOMMENDATION WHICH TIES COLONY'S RATES DIRECTLY TO FTWA'S RATES, WHAT WOULD HAPPEN IF FTWA CHANGES ITS RATES?

A.In the event that FTWA changes its rates, I would recommend that the Commission institute a simplified filing requirement for Colony to change its rates. I recommend that a procedure be established which would permit Colony to provide the Commission with the following information:

1. A copy of FTWA's new rate schedule;
2. A calculation showing the application of FTWA's new rate schedule to the average Colony customer usage (similar to my Schedule 2);
3. A simple income statement which would show that the new rates would not result in Colony's revenues greatly exceeding its costs; and
4. Certification that all customers received 60 days' notice of the rate change.

I would emphasize that, if a rate change would be a general rate increase under Section 1308(d) of the Public Utility Code, Colony still would be required to provide notice of the proposed increase to its customers and the customers would retain the right to challenge the increase. It is my belief that this type of procedure would continue to protect Colony's customers, yet permit Colony to change its rates without spending exorbitant amounts on rate case expense.

Q. HAS THE COMMISSION USED SUCH A PROCEDURE IN OTHER INSTANCES?

A. I am aware of one instance which is similar to this case. The Borough of Kutztown provides service to approximately 1500 water and sewer customers. About 35 sewer customers and 110 water customers reside outside of the Borough limits and, thus, are subject to regulation by the Commission. In July 1991, the Borough filed a petition with the Commission seeking a simplified procedure for changing the rates for the customers subject to the Commission's jurisdiction. The Borough committed to charging exactly the same rates for customers within the Borough and those outside of the Borough. It sought permission to change its rates by filing a certified copy of its ordinance (including the new rate schedule) with the Commission. The Commission approved this procedure, with some modifications, as follows:

That the Borough of Kutztown shall maintain on file with the Commission a certified copy of its effective local ordinances, and rules and regulations pertaining to water and sewer rates and service, as changes occur.

That the Borough of Kutztown is not to construe this waiver as permission to forego the filing of Annual Reports already required by the Commission which includes an annual accounting of the number of customers located inside and outside the Borough limits ....

That the sixty (60) day plain language notice of proposed changes in water and sewer rates shall be provided to outside customers and to the Commission in accordance with our regulations. ...

That the granting of the Petition shall not be construed as granting a waiver of the Borough's burden of proof in any proceeding before the Commission ....

In re: Petition of the Borough of Kutztown, P-910529 (Feb. 5, 1992), slip op. at 2-3.

Q.PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A.I recommend that Colony's rates be set equal to the rates which its customers would pay if they were direct, retail customers of Fairview Township Water Authority. In the present case, this would result in a 125% rate increase for Colony's customers, in lieu of the 385% increase proposed by Colony. I also recommend that the Commission waive its filing requirements to authorize Colony to use a simplified procedure to change its rates in the future if FTWA changes its retail rates. It is my belief that this is a fair result for both Colony and its customers.

Q.DOES THIS CONCLUDE YOUR TESTIMONY?

A.Yes, it does.

COLUMBIA STATEMENT NO. 16-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pa. Public Utility Commission	:	
v.	:	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	:	
	:	

REJOINDER TESTIMONY OF

JAMES H. CAWLEY

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

September 21, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is James H. Cawley.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes, I prepared written rebuttal testimony on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia") which was served to the parties on August 26, 2020 to provide my expert opinion regarding the direct testimony of Scott J. Rubin filed on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") on July 28, 2020.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. My purpose is to respond to new assertions made by Mr. Rubin in his surrebuttal testimony (OCA St. No. 1SR) at pages 4-11 which was served by OCA on September 16, 2020.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I summarize my conclusions and recommendations on rejoinder as follows:

- Mr. Rubin's denial that rates would "yo-yo" with the economy under his ratemaking method because he does not advocate a rate reduction but merely a rate freeze is a distinction without a difference.
- Neither Columbia's thirteen-year drought between rate cases nor a comparison of Columbia's earned returns with U.S. Treasury 30-year yields establishes that it was over-earning or prove that Pennsylvania regulation fails to constrain utility rates.
- Rather than stating that it would be improper to favor customers' interests over investors' interests in times of economic distress, I instead plainly stated that customers' and investors' interests must always be balanced when setting just and reasonable rates.
- The Pennsylvania Public Service Commission carefully studied the effects of the Great Depression for over four years before adopting a 1934 resolution lowering allowed returns on investment from 7 percent to 6 percent. The PSC, however, acted primarily if not exclusively in reaction to menacing demagoguery and in a wholly arbitrary manner with an across-the-board return reduction which provides no justification or precedent for this Commission's acceptance of Mr. Rubin's suggested denial of Columbia's requested revenue increase because of the current economic conditions.

- Mr. Rubin wrongly brands Columbia as a "competitive business" that "cannot sustainably raise [its] prices when [its] customers' incomes have decreased significantly." In fact, the consumer-price index rose a seasonally adjusted 0.6% in both June and July, following declines in March, April, and May amid the pandemic's initial economic fallout. Likewise, the producer-price index also rose a seasonally adjusted 0.6% in July, the largest monthly rise since October 2018.

III. RESPONSES TO MR. RUBIN (OCA St. No. 1SR)

Q. HAVE YOU REVIEWED THE SURREBUTTAL TESTIMONY OF MR. RUBIN, OCA STATEMENT NO. 1SR?

A. Yes.

Q. DOES MR. RUBIN DISAGREE WITH YOUR REBUTTAL TESTIMONY THAT COLUMBIA'S RATES SHOULD NOT 'YO-YO" WITH CHANGING ECONOMIC CONDITIONS?

A. Yes. On page 15 of my rebuttal testimony, I stated that "allowing utility rates to 'yo-yo' with the economy would jeopardize not only Columbia's financial stability but also its service reliability and safety." Mr. Rubin disagrees by saying that he is not suggesting that Columbia's rates be reduced, only that they not be increased to promote "rate stability until we have a better understanding of the long-term impacts of the pandemic on the economy in the Company's service territory."[1]

Q. WHAT IS YOUR RESPONSE?

A. As I understand his proposed ratemaking method, it is entirely customer-centric, with consideration of only the state of the economy and its effect on Columbia's customers. Because the economy fluctuates, affecting customers variably, I described his method as having a "yo-yo" effect, which unavoidably would occur when only these two dispositive criteria are considered. Instead, ratemaking methodology should be constant, not changing to reach a desired result in distressed economic conditions while remaining "traditional"

[1] OCA St. No. 1SR, p. 4.

during more prosperous economic conditions. Customer-centric ratemaking also contravenes the constitutional requirement of balancing customer and investor interests, an established principle that Mr. Rubin acknowledged.[2] Finally, as I noted earlier,[3] in the absence of guiding standards in Mr. Rubin's ratemaking method, Columbia will be unable to decide when to file another rate case and meanwhile will not receive a return on large-scale investments made in 2020 and those planned for 2021.

Q. DOES MR. RUBIN ALSO DISAGREE WITH YOUR REBUTTAL TESTIMONY THAT UTILITY RATES ARE CONSTRAINED BY THE REGULATORY PROCESS?

A. Yes, he disagrees with the very next sentence on page 15 of my rebuttal testimony: "To ensure against such adversities, utility regulators are empowered to set the rates, terms, and conditions of service of privately owned utilities." He claims that this sentence is based "on some notion of regulatory theory rather than the actual history of regulation in Pennsylvania."[4] In an attempt to prove his point that Pennsylvania regulation did not constrain Columbia's earnings during favorable economic circumstances (between settlement of its 1984 rate case in December, 1985, until the filing of its next rate case in January, 2008), he cites the Company's earned returns as exceeding 30-year Treasury yields during the same period.

[2] OCA St. No. 1, p. 5 ("In setting rates, regulators should attempt to balance the interests of all relevant sectors of the public.").

[3] Columbia St. No. 16-R, pp. 12 & 17.

[4] OCA St. No. 1SR, p. 4.

Q. WHAT IS YOUR RESPONSE?

A. First, my statement was merely meant to describe the Commission's role in ensuring that public utilities within its jurisdiction earn returns within the "zone of reasonableness," neither below the zone (confiscatory) nor above the zone (exorbitant or exploitative).

Second, 30-year U.S. Treasury yields are not appropriate or fair comparisons with investor-owned, regulated public utility earned returns. Investors in public utility debt and equity securities demand higher yields than extremely conservative, risk-free U.S. Treasury security yields.

Third, Mr. Rubin does not identify with certainty what factors allowed Columbia to refrain from filing a rate case other to speculate that declining interest rates, increased sales, or operating efficiencies may have contributed to the Company's decisions. That speculation is undermined by Columbia witness Kitchell's direct testimony at pages 3-4 (Columbia Statement No. 14), which demonstrates that "From 2007 through 2019, Columbia's replacement program eliminated an average of 437,756 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." Accordingly, the circumstances that enabled Columbia to avoid seeking rate relief prior to 2008 do not support Mr. Rubin's contention that Columbia is currently able to do so.

If Columbia had been over earning during the thirteen year period prior to 2008, the OCA (where Mr. Rubin held increasingly responsible positions from 1983 through January 1994) as well as the Commission could have invoked Public Utility Code Section 1310 and, respectively, advocated or set temporary rates, but neither did so. The Commission may simply have wished to encourage operating efficiencies and customer growth by not curtailing the Company's earned returns and concluded that those returns remained within the zone of reasonableness.

Q. ON PAGE 7 OF HIS SURREBUTTAL TESTIMONY, DOES MR. RUBIN DESCRIBE YOUR REBUTTAL TESTIMONY ON PAGE 19 AS SAYING THAT UTILITY RATES SHOULD NEVER BE REDUCED IF ECONOMIC CONDITIONS ARE SEVERE, AND THAT IT WOULD BE IMPROPER TO FAVOR CUSTOMERS' INTERESTS OVER INVESTORS' INTERESTS IN TIMES OF ECONOMIC DISTRESS?

A. Yes, he says that, which is not an accurate description of my testimony. I plainly stated just the opposite, that favoring either customers' or investors' interests "would be a distortion of the most accepted principle of utility ratemaking announced in the famous *Hope* decision by the U.S. Supreme Court: rates are defined to be just and reasonable if they *balance* consumer and investor interests. The public interest is determined by a balancing of the interests without favoring either of them."[5]

Nor have I ever said that utility rates may never be reduced, and, as Mr. Rubin points out on page 4 of his surrebuttal testimony, he is not advocating a rate reduction in this case. He advocates a complete denial of rate relief considering only customers' interests, whereas I advocate a balancing of customers' and investors' interests, where customers' interests in reliable and safe service may predominate over affordability concerns that can be addressed by federal, state, and Columbia programs (described on page 29 of my rebuttal testimony).

Q. DOES MR. RUBIN CITE A 1934 PENNSYLVANIA PUBLIC SERVICE COMMISSION RESOLUTION LOWERING RATES DURING THE GREAT

[5] Columbia St. No. 16-R, p. 19 (emphasis original) (citing *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)).

DEPRESSION AS PRECEDENT FOR COMPLETELY DENYING COLUMBIA'S REQUEST FOR AN INCREASE IN REVENUES?

Yes, he cites a Public Service Commission ("PSC") resolution adopted in 1934 as precedent for denying Columbia rate relief here and for reducing rates generally during distressed economic conditions.[6] He also quotes from a history of the Philadelphia Electric Company ("PECO"),[7] in support of his position that the "PSC lowered rates substantially during the Great Depression based (at least in part) on prevailing economic conditions, as stated in the 1934 resolution."[8]

Q. DO THE CITED REFERENCES SUPPORT MR. RUBIN'S TESTIMONY?

A. No, the resolution was arbitrarily adopted and implemented, as the PECO history makes clear, and notably was not adopted until over four years after the onset of the Great Depression, after the PSC better understood the resulting economic effects.

By resolution, the PSC first initiated an investigation on April 5, 1932, by a two-commissioner committee which was directed to hold conferences principally with the Commonwealth's electric utilities (although it met with other utilities as well) "concerning the reasonableness of [their] rate schedules and structures" with the committee's findings to be reported to the full Commission. The committee's report resulted in a further resolution adopted on April 2, 1934:

> That so long as the present economic conditions of the country exist, this Commission believes that an annual rate of return of 6 per centum to public service companies in its jurisdiction is a fair and reasonable return on the value of the property used and useful in the rendition of the service to the

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[6] OCA St. No. 1SR, p. 7.

[7] Nicholas B. Wainwright, HISTORY OF THE PHILADELPHIA ELECTRIC COMPANY: 1881-1961 (Philadelphia, PA 1961), available without charge at https://babel.hathitrust.org/cgi/pt?id=mdp.39015081291844&view=1up&seq=335. As noted below, I attach relevant pages as Exhibit JHC-3.

[8] OCA St. No. 1SR, p. 8.

> public; and further, that the Commission confer with representatives of the public service companies earning more than a fair return upon this basis for the purpose of having them revise their rate structures to conform to this annual rate of return.[9]

Unlike the present circumstances, where Mr. Rubin proposes a punitive rate increase denial on Columbia when the pandemic has occurred for less than a year, the PSC did not take action until well after the onset of the Depression which began with the stock market crash in September-October, 1929. The PSC assessed the effect of the economic dislocation for over four years before adopting the resolution in the spring of 1934. Until then, the PSC continued to award rates of return of 7 percent.[10]

The PECO history describes how the PSC's across-the-board one percent reduction in returns of all jurisdictional public utilities was arbitrarily adopted in 1934 by resolution (not by order after due process notice and opportunity for hearing). It was consistently applied without regard to substantial contrary evidence of record,[11] by a majority of PSC members appointed by Governor Gifford Pinchot[12] before the Commission was given the authority in 1937 to adopt temporary rates subject to due process protections. The PECO history leaves little doubt that the PSC's actions were motivated by scurrilous political

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[9] *Re Utility Rates During Economic Emergency*, 3 P.U.R. NS 123, 125 (Pa. P.S.C. 1934), attached hereto as Exhibit JHC-4.

[10] *See City of Scranton v. Scranton-Spring Brook Water Service Co.,* 10 Pa. P.S.C. 609 (1930); *Ruttle v. Cheltenham & Abington Sewerage Co*., 10 Pa. P.S.C. 502 (1931); *Borough of Honesdale v. Honesdale Consolidated Water Co.,* 10 Pa.P.S.C. 653 (1931); *Reeves v. Highspire Water Supply Co*., 11 Pa. P.S.C. 143 (1931); *Weinhold v. Pennsylvania Chautauqua*, 12 Pa. P.S.C. 230 (1933); *Taxpayers Protective Association of Easton v. Lehigh Water Co*., 14 Pa. P.S.C. 1 (1936) (7% return for the period October 1, 1931 to March 15, 1933, and 6% return "designated by the Commission on April 2, 1934, as the allowable rate of return" for the period March 15, 1933, forward).

[11] *See, e.g., Taxpayers Protective Association of Easton v. Lehigh Water Co*., 14 Pa. P.S.C. 1 (1936) (7% return for the period October 1, 1931 to March 15, 1933, and 6% return "designated by the Commission on April 2, 1934, as the allowable rate of return" for the period March 15, 1933, forward).

[12] When Pennsylvania governors constitutionally served single four-year terms, Gifford Pinchot served as governor from January 16, 1923 to January 18, 1927, and again from January 20, 1931 to January 15, 1935.

demagoguery and achieved by unseemly informal arm-twisting with the threat of lengthy formal proceedings for those companies that did not "voluntarily" comply.

I attach Exhibit JHC-3, consisting of relevant pages 224-228 and 246-247 from Mr. Wainwright's history of PECO to support my opinion that the PSC's mandated rate reductions were not "based (at least in part) on prevailing economic conditions, as stated in the 1934 resolution," as Mr. Rubin alleges, but were primarily if not exclusively and very inappropriately made in reaction to menacing demagoguery by candidate and then Governor Pinchot and even by the PSC's chief counsel Richard J. Beamish (later one of the five inaugural PUC members in 1937). As such, the PSC's actions from 1934 to 1937 provide no precedent or justification for Commission acceptance of Mr. Rubin's suggested denial of Columbia's requested rate relief because of the current economic conditions.

Rather than repeating in this case the arbitrary ratemaking mistakes of the PSC during the Great Depression, the Commission should heed this observation in the updated edition of the most classic of public utility law treatises (first published by James C. Bonbright in 1961[13]), "In more recent years, business-cycle experts have become skeptical of proposals to combat a depression by enforced reductions of administered prices, and attention has been turned to other alternatives including the possibility of using the versatile machinery of government to encourage private utilities *to maintain their construction and equipment budgets*, even when their existing plants are partly idle because of a temporary drop in demand."[14]

[13] *Available at* file:///C:/Users/J%20and%20K/Downloads/1961%20EDITION%20JAMES%20C.%20BONBRIGHT'S%20PRINICIPLES%20OF%20PUBLIC%20UTILITY%20RATES%20(L0898246xA35AE)%20(1).pdf.

[14] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, PRINCIPLES OF PUBLIC UTILITY RATES (2d ed. 1988), PPUR CH 14, 2005 WL 998348 at 22 (emphasis added).

Q. DOES MR. RUBIN OFFER SUPPORT FOR HIS PREVIOUS ASSERTION THAT "REGULATION IS SUPPOSED TO BE A SUBSTITUTE FOR MARKET FORCES,…COMPETITIVE BUSINESSES CANNOT SUSTAINABLY RAISE PRICES WHEN THEIR CUSTOMERS' INCOMES HAVE DECREASED SIGNIFICANTLY?"[15]

A. Yes. In an attempt to support the concept that "regulation is supposed to be a substitute for market forces," Mr. Rubin quotes the Commission's decision in *Pa. PUC v. Duquesne Light Co.*, 59 Pa. PUC 67, 91 (1985).[16]

Q. PLEASE RESPOND.

A. I still disagree with his assertion of this concept for the reasons I stated in my rebuttal testimony.[17] Columbia is not a competitive business, and competitive market pricing is incompatible with the regulation of natural monopolies like public and municipal utilities. For that reason, for example, the Pennsylvania General Assembly restructured the Commonwealth's electric and natural gas industries by permitting competitive market commodity pricing by non-public utility Electric Generation Suppliers and Natural Gas Suppliers, but maintained traditional regulation of electric and natural gas public utilities.

In fact, competitive businesses *are* sustainably raising their prices during this period of economic dislocation. THE WALL STREET JOURNAL reported on August 12, 2020, that "U.S. consumer prices rose in July on higher costs for a range of products and services … as demand for goods rebounded following steep declines earlier in the coronavirus pandemic."[18] In the same article, the JOURNAL further reported that:

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[15] OCA St. No. 1, p. 9.

[16] OCA St. No. 1SR, p. 10.

[17] Columbia St. No. 16-R, pp. 20-21.

[18] https://www.wsj.com/articles/july-consumer-prices-rise-amid-increased-demand-for-a-range-of-goods-services-11597236743. See also the U.S. Department of Labor, Bureau of Labor Statistics news release entitled "Consumer Price Index – July 2020" at bls.gov/news.release/pdf/cpi.pdf.

> The consumer-price index—which measures what consumers pay for everyday items including driving fuel, clothing and electricity—climbed a seasonally adjusted 0.6% in July, the Labor Department said Wednesday. The rise was the second in as many months. The index also rose 0.6% in June, which was seen as a potential turning point for consumer prices, following declines in March, April and May amid the pandemic's initial economic fallout. ***
>
> The rise in consumer prices last month aligns with an increase in the producer-price index, a measure of the prices businesses receive for their goods and services. That index rose a seasonally adjusted 0.6% in July, the Labor Department reported Tuesday, the largest monthly rise since October 2018.

Mr. Rubin's quotation from the 1985 Duquesne Light Company rate case is also inapt. The quoted passage[19] seeks to align monopoly utilities with competitive businesses by the expedient of regulation, which, again, is an unsupportable proposition, as I explained in my earlier testimony.

The quotation is further inapt because it is dicta in a discussion of the reasonableness of approving cash working capital claims involving deferred coal costs. Mr. Rubin elevates a sentence from a discussion of a single rate case element in an effort to prove the overriding proposition that no rate relief should be granted, which in my view is a bridge too far.

IV. CONCLUSION

Q. DOES THAT COMPLETE YOUR REJOINDER TESTIMONY?

A. Yes.

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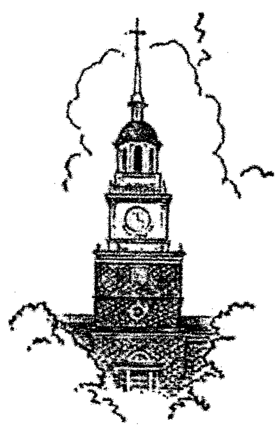
[19] "Even in general business enterprises, unfortunate or inexpedient management expenditures, even if prudently made, may not always be totally recovered from their customers; the market may not so permit as customers may reject the product or service at such cost. *Regulation provides a substitute for market influences so as to protect the interest of captive customers of the public utility*." *Pa. PUC v. Duquesne Light Co*., 59 Pa. P.U.C. 67, 91 (1985), 1985 Pa. PUC LEXIS 68, *55 (emphasis added).

HISTORY

OF THE

PHILADELPHIA ELECTRIC COMPANY

1881 · 1961



By NICHOLAS B. WAINWRIGHT

PHILADELPHIA 1961

Philadelphia Electric's common stock was not quoted because it was not traded, nearly all of it being owned by U.G.I. However, the Company did have a preferred issue outstanding, its five-dollar dividend issue, par one hundred. This issue was little affected by the depression, selling usually above par and never declining below 87. When additional shares were offered in 1931, the entire issue was oversubscribed in a single day.

Hysteria selling, however, rather than confident buying characterized these lean times and brought on horrifying failures. The most notable collapse of all was that of Samuel Insull. By 1930, the utilities built and managed by him produced one tenth of the nation's electricity. Their service extended to 5,000 communities in thirty-two states, most of which had been without electricity in 1914. In April, 1932, Insull's holding companies—none of the operating companies failed—went into receivership, taking with them the savings of thousands of investors. This disaster became a political issue in an election year, and Insull was forced to stand trial on many charges, but was acquitted on all counts. Despite the legal verdict, Insull's career remained a source of acute embarrassment to the electric industry.

The market crash stimulated politicians to turn their guns on public utilities. Both Pennsylvania and New York were the scenes of gubernatorial contests in 1930, and the successful candidates, Gifford Pinchot and Franklin D. Roosevelt, made utility regulation and rates major issues in their campaigns.

Pinchot, a progressive-prohibitionist Republican, declared at the outset that the Public Service Commission of Pennsylvania was "the catspaw" of the utility corporations and was "useless or worse." He announced his intention "to break the stranglehold of the electric, gas, water, trolley, bus, and other monopolies on the cost of living and the government of the state." By a slim margin, he won the Republican primary in May, 1930, and then continued his vigorous campaign, inveighing constantly against the utilities. In October, he charged that industries were leaving Philadelphia because Philadelphia Electric's rates were so high. U.G.I. mailed a letter to each of its 95,000 shareholders denying this, and pointing out that rates in Philadelphia were five per cent lower than the average in the United States. Praising Philadelphia Electric for its six voluntary rate reductions during the previous six years, the letter stated, "To attempt to break down the confidence of the public in the utilities in order to serve selfish political ambition is neither fair nor decent."

Although he failed to carry a single ward in normally Republican Philadelphia, and even lost that stronghold of Republicanism, Montgomery County, Pinchot eked out a victory in November. Stirred by bitter memories of the utter failure of the giant power schemes of his first administration, Pinchot lashed out at the utilities in his inaugural address on January 20, 1931. "The task today is to defeat the attack of the public utilities . . . upon the rule of the people." With reference to the Public Service Commission, "We have no more compelling duty than to destroy the corruption upon which the power of the utilities depends." And finally, "Back of the public utilities in their attack on our American form of government is the whole fabric of political corruption, the underworld, the protected racketeer, and criminals of low and high degree." That Pinchot did not back up these inflammatory statements with a single instance of corruption cannot be credited to any sense of timidity on his part. Had he known of any, he would have used the example for all it was worth.

No matter what a utility did, it was wrong. When Philadelphia Electric made one of its customary rate reductions, Pinchot was not pleased. In a radio talk in February, 1931, he warned the public to beware of the Company's "trick," for "the boasted rate reduction occurred in a consumption range rarely reached by the average consumer." Since this reduction was in the first step of the rate and benefited every residential consumer in Philadelphia, President Taylor protested to Pinchot that such a statement "may seriously affect the cordial relations which have existed for so many years between the Philadelphia Electric Company and its customers." This, of course, was exactly what Pinchot wanted to do. Taylor urged him "in the spirit of fair play, to correct the erroneous impressions created by your public utterances." The appeal went in vain.

Pinchot launched a sweeping investigation of the Public Service Commission and championed bills to abolish that agency of the legislature, substituting for it an executive agency—the Fair Rate Board—accountable only to himself. In an appearance before the judiciary committee of the state senate, Zimmermann protested against this arbitrary power: "Do you think that a man who attacks the utilities in such a violent manner and often without regard for the facts is fit to be entrusted with the sole power of hiring and firing the members of the Commission?" Evidently, the committee did not believe that Pinchot was ideally suited for the responsibility, for it killed his fair rate bills. In any event, had the bills passed, it is probable they would have been declared unconstitutional.

Pinchot was furious. He likened the Public Service Commission to a "malignant cancerous growth" which was "sapping the life blood of the people." But he could do nothing about it. In 1932, he traveled the state, making a political issue of alleged excessive electric rates. During all this time, he had failed to uncover any corruption, but in the summer of 1932 he was handed some ammunition. A disgruntled person seeking to strike at Mitten Management fabricated a tale that Mitten had given large bribes to W. D. B. Ainey, who for seventeen years had been a member of Pennsylvania's Public Service Commission and was currently its chairman. Pinchot instantly accepted the story, announcing that he had "conclusive evidence that Ainey had sold the public out." A full-scale investigation was held, but no evidence of wrongdoing was uncovered. Ainey denied that he had received bribes from Mitten, and it was soon quite clear that he was innocent.

Then, a damaging light was brought to bear on Ainey. It was disclosed that in 1926 Arthur W. Thompson of U.G.I. had paid a hospital bill for Ainey amounting to $3,000. Pinchot was delighted. He wrote a friend, "We are having a gay old time up here, and I think we have got Mr. Ainey cold."* Another inquiry was ordered, but Ainey resigned. Protesting that he had never done anything wrong, the commissioner wrote that the precarious condition of his health and his lack of financial means for litigation prevented him from defending his reputation.

Here at last was a triumph for Pinchot, who ridiculed Ainey's reasons for avoiding investigation. But Ainey, a distinguished-looking man of reputation as a utility expert, a former president of the national association of utility commissioners, president of the state Y.M.C.A., a man generally believed to be a good public servant, had not exaggerated the condition of his health. He survived his resignation by only a month.

Pinchot was but one of many political leaders engaged in a bitter attack on the electric industry. Senator George W. Norris of Nebraska, referring to the "power trust," called it "the most disgraceful and far-reaching and

* M. Nelson McGeary, *Gifford Pinchot, Forester-Politician* (Princeton, 1960), 367.

shameful combination that has ever been organized by man," and declared that its leaders had "never done anything except to feather their own nests and deceive the very people who by their pennies contribute to their wealth."

Orators who indulged in diatribes naturally did not stress the accomplishments of the American electric industry. They neglected to mention that the United States enjoyed the most extensive and the cheapest electric service in the world; that the creation of the American electric power industry represented an outstanding national achievement; that while the cost of living in 1931 was fifty per cent higher than in 1913, the average cost of electricity to the consumer had shrunk thirty-one per cent during that period. If electric rates were high, at least they had been going down steadily, while the cost of almost everything else was rising.

It was rather ironic that government representatives should have been so critical of declining electric bills at a time when the taxes they were creating were rising sharply. How many liberal politicians who maintained that rates were too high voted against taxes proposed for utilities? In 1932, Philadelphia Electric's tax bill had risen to $5,856,697, up more than half a million dollars for the year despite declining earnings. Taxes had become an important part, and an uncontrollable part, of the rate structure. They tended to postpone rate reductions and threatened, indeed, to cause a rise in rates!

That the industry needed regulation was true enough, and many utility leaders looked forward to reforms in commission regulations, in financial statements, and in holding company operations. However, they refuted the charge that there was a "power trust," and they fought against public ownership of utilities. Much of the criticism directed at the industry by men like Senator Norris was

However, in common with other utilities, the Company did encounter major problems at the state level.

Caught up in the New Deal cyclone that swept the country in 1934, Democrat George H. Earle was elected governor of Pennsylvania. In his inaugural address, Earle called for lower utility rates, and pledged, "This administration will introduce a public utility law so stringent that no Public Service Commission can stultify it without full public knowledge."

Meanwhile—Earle's law was not passed until 1937—the Public Service Commission, its members nearly all Pinchot's reform appointees, were busily reducing rates. In 1934, the Commission limited the return allowable to utilities to six per cent (it had been seven per cent), and between January 1, 1933, and June 30, 1936, it obtained rate reductions totaling $15,000,000 from Pennsylvania operating companies. These reductions were nearly all achieved by informal conferences at which the commissioners set up a tentative rate base and endeavored to show the utility that it was earning more than a fair return. In general, the alternatives were either voluntary reduction of rates or formal proceedings if the Commission felt that such proceedings could be successfully maintained. Officials of Philadelphia Electric were in frequent conference with the commissioners, and the Company lowered its rates substantially in 1933, 1934, 1935, and 1936. Nonetheless, these reductions were not large enough to satisfy Governor Earle. In September, 1936, he charged that rate schedules were producing more than the maximum six per cent profit allowed, and declared that no real rural electrification plan had ever been worked out in Pennsylvania. He demanded that the Commission cooperate with the R.E.A. to electrify farm homes in all parts of the state. Richard J. Beamish, the vocal counsel for the Commission, took up the cry. In a radio address, he asserted that rates were too high, rural electrification had been a "fake," utility executives were in partnership with the Republican state organization, and that "through mergers, write-ups and dizzy bookkeeping methods, Pennsylvania operating companies were being milked of their profits for the benefit of big-wig New York heads of holding companies."

The end of the Republican-dominated Public Service Commission had been in sight since Earle's election. In 1937, it was dissolved and superseded by a five-man Public Utility Commission. Committed to a policy of sweeping rate reductions, the new Commission was granted extremely broad powers, including the right to declare temporary rate reductions. Its expenses were to be paid by the utilities themselves.

The Commission moved rapidly, declaring rate reductions for one company after another. In October, 1937, it ordered Philadelphia Electric to slash its rates by $3,146,000, the largest reduction yet imposed on a Pennsylvania utility. Beamish, now a member of the Public Utility Commission, glibly suggested that $3,000,000 more should be cut off. Fortunately, the other commissioners were more interested in making fair rates than headlines.

Although it was the aim of government to increase the prices of commodities, services, and labor, government officials were at the same time dedicated to the principle of reducing electric rates. They argued that if the rates were reduced more people would buy electricity and the utilities would not suffer. Unlike some of the other major systems, Philadelphia Electric had always made its rate reductions voluntarily until the enforced reduction of 1937. Of course, had it not done so, similar reductions pal field before the utilities law was enacted. As to cities which had not obtained such vested right, the state may restrict their rights to operate in that field as it sees fit.

It has seen fit, as declared in the Chilton Case, to restrict their rights of operation in that field where an existing utility is so operating under an indeterminate permit by requiring them to procure a certificate of convenience and necessity before they can so operate. If the existing utility does not provide adequate service or does not provide service at reasonable rates, the city may apply to the Public Service Commission for relief and procure it.

The order of the circuit court is reversed with direction to enter an order sustaining the demurrer and for further proceedings according to law.

Owen, J., took no part.

PENNSYLVANIA PUBLIC SERVICE COMMISSION

Re Utility Rates During Economic Emergency

Return, § 20 — Emergency return during economic depression.

1. The Commission unanimously adopted a resolution during a period of economic depression that so long as emergency conditions continue to exist an annual rate of return of 6 per cent to utilities operating within the state would be regarded as a fair and reasonable return on the value of property used in rendering service to the public, p. 123.

Rates, § 644 — Informal procedure for statewide reductions — Economic depression.

2. Pursuant to a resolution unanimously adopted by the Commission to restrict all utilities in the state to 6 per cent return during an economic emergency period, the Commission's bureau of accounts, rates, and statistics was instructed to base its rate studies on annual reports filed by utilities with the Commission—and to report the results of such studies to the Commission for use as the basis for informal conferences with the representatives of all utilities showing a return in excess of 6 per cent with a view to obtaining a rate reduction in such cases, p. 123.

[April 2, 1934.]

RESOLUTION *adopted by the Commission on motion of one of the Commissioners declaring the policy of the Commission affecting future procedure and principles controlling utility rate fixing throughout the state.*

By the COMMISSION: [1, 2] *Whereas,* this Commission on the 5th day of April, 1932, adopted the following resolution:

"Now, therefore, be it *resolved:* That the Chairman of the Public Service Commission be and is hereby requested to appoint a committee of two Commissioners who shall hold conferences with electric utility companies in Harrisburg and at other places in the commonwealth designated by the Chairman, and utilize in the conduct of these conferences information and assistance from the records, bureaus, and personnel of the Commission, and shall promptly report to the Commission the results of their investigation concerning the reasonableness of the rate schedules and structures, with particular emphasis upon domestic rates, and advise the Commission with respect to the means of making such rate schedules and structures just and reasonable. To that end the designated Commissioners shall promptly hold conferences with the electric companies of Pennsylvania, and the Chairman and the secretary of the Commission are authorized and directed to request the attendance of accredited representatives of the electric utilities at these conferences."

and,

Whereas, pursuant to said resolution, the Commission has engaged continuously in conferences not only with the electric utility companies, but with companies rendering other forms of public service; and,

Whereas, under the rules and practice of this Commission, all public service companies under its jurisdiction were required and did file their annual reports for the year 1933 on or before March 31, 1934; and,

Whereas, this Commission should take cognizance of the present economic conditions prevailing in the United States and as such economic conditions particularly affect the welfare of the people of this commonwealth; and,

Whereas, this Commission has given deep study to the proposition of what is a fair return to the utilities of Pennsylvania, giving consideration to the rate of return prudent investors may expect upon securities represented by all types of businesses, to the fact that the allowed fair return bears directly upon the rates charged every consumer and is, therefore, of vital importance to practically the entire population of Pennsylvania, and to every other factor necessarily involved; and,

Whereas, the Supreme Court of the United States has laid down the following rule (Bluefield Water Works & Improv. Co. v. West Virginia Pub. Service Commission, 262 U. S. 679, 692, 67 L. ed. 1176, P.U.R.1923D, 11, 20, 43 S. Ct. 675, quoted in United R. & Electric Co. v. West, 280 U. S. 234, 74 L. ed. 390, P.U.R.1930A, 225, 228, 50 S. Ct. 123, and Los Angeles Gas & E. Corp. v. California R. Commission, 289 U. S. 287, 319, 77 L. ed. 1180, P.U.R.1933C, 229, 249, 53 S. Ct. 637):

"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; . . ."

and has further declared (Dayton-

Goose Creek R. Co. v. United States [1924] 263 U. S. 456, 481, 68 L. ed. 388, 44 S. Ct. 169, 33 A.L.R. 472:

"By investment in a business dedicated to the public service the owner must recognize that, as compared with investment in private business, he cannot expect either high or speculative dividends. . . ."

Now, therefore, April 2, 1934, be and it is hereby *resolved:* That so long as the present economic conditions of the country exist, this Commission believes that an annual rate of return of 6 per centum to public service companies in its jurisdiction is a fair and reasonable return on the value of the property used and useful in the rendition of the service to the public; and further, that the Commission confer with representatives of the public service companies earning more than a fair return upon this basis for the purpose of having them revise their rate structures to conform to this annual rate of return; and further, that the bureau of accounts, rates, and statistics be directed to use this basis for its study and analysis of the annual reports for the year 1933 filed by the public service companies on or before March 31, 1934, in accordance with the policy of the Commission adopted on the 5th day of April, 1932, and to report to the Commission the result of the study for such further action as the Commission may determine.

INDIANA PUBLIC SERVICE COMMISSION

Re Discounts and Penalties

[No. 11683.]

Payment, § 53 — Gross and net rates — Penalties.

1. The practice should be discontinued of providing in rate schedules for so-called gross and net rates and penalties for default in the payment of service bills, p. 126.

Rates, § 171 — Schedules — Uniformity for utilities.

2. There should be substantial uniformity in rate tariffs of the utilities of the state, p. 126.

Service, § 162 — Rules and regulations — Uniformity for utilities.

3. There should be substantial uniformity in rules, regulations, and practices of the utilities of the state, p. 126.

Payment, § 2 — Uniform regulations.

4. There should be more uniformity in the practices of public utilities of the state with respect to the collection of patrons' service bills, and with respect to penalties, charges, and/or discounts, p. 126.

Payment, § 53 — Discount for promptness — Collection or deferred payment charges.

5. Utilities should be permitted to provide by appropriate tariff provisions

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2020-3018835

Columbia Gas of Pennsylvania, Inc.

Statement No. 17-R

Rebuttal Testimony of
Toby Bishop

Topics Addressed: **Economic Impacts of Columbia Gas of Pennsylvania's 2020 and 2021 Capital Expenditures**

Dated: August 26, 2020

I. INTRODUCTION

Q. Please state your name, employer, business address and current employment position.

A. My name is Toby Bishop, and I am a Senior Vice President of Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. On whose behalf are you submitting this testimony?

A. I am sponsoring rebuttal testimony on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or the "Company").

Q. Please describe your professional background and experience.

A. I have over 25 years of experience consulting in the North American energy industry regarding natural gas and electric matters. My natural gas experience includes assisting clients in the United States and Canada with a wide range of issues, including: policy and strategic issues; asset valuation; economic analysis; rate and financial matters; market power; litigation/arbitration support and damages; market assessments; and project development matters. My experience has included federal, state and provincial rate proceedings in the United States and Canada on behalf of natural gas and electric utilities, natural gas pipelines, natural gas storage operators, and unregulated energy firms. I have also assisted various clients throughout North America with market-related matters and have prepared numerous assessments of market dynamics, including the economic impacts of natural gas infrastructure that have been filed with the Federal Energy Regulatory

Commission and used publicly for development initiatives. I have provided expert testimony on numerous occasions before regulatory agencies across North America. A copy of my résumé and a listing of the testimony I have sponsored is attached as Exhibit TB-1.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or other regulatory agencies?

A. Yes, I submitted testimony in Docket No. R-2019-3015162. In addition, I have also provided testimony on numerous occasions before federal and provincial regulatory agencies in the U.S. and Canada.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimonies of Pennsylvania Office of Consumer Advocate ("OCA") witnesses Scott J. Rubin and Jerome D. Mierzwa, the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") witness Mitchell Miller, the Community Action Association of Pennsylvania ("CAAP") witness Susan A. Moore, and the Columbia Industrial Intervenors ("CII") witness Frank Plank regarding the recent economic circumstances in Pennsylvania. These witnesses recommend that it would not be just or reasonable to increase the Company's rates at this time based on the negative economic consequences of the pandemic and the impact that rate increases would have on Colombia Gas's customers, particularly low-income customers. Specifically, Mr. Rubin recommends that the

Commission should deny any rate increase to Colombia Gas in this proceeding.[1] Mr. Mierzwa references Mr. Rubin to support his position that no rate increase should be granted given the health of the economy, unemployment levels and economic uncertainty due to the pandemic.[2] Mr. Miller states that the Commission should not approve any rate increase.[3] Ms. Moore recommends that no rate increase be granted under the current economic conditions, and if a rate increase is allowed then the Company should increase funding for low income programs.[4] Mr. Plank recommends that the Commission deny the requested rate increase, but if a rate increase is allowed, then recommends that the Commission significantly limit any rate increase to the Large Distribution Service rate class.[5]

While witnesses Rubin, Mierzwa, Miller, Moore and Plank support their recommendations based on the negative economic consequences of the pandemic, namely high unemployment, the partial reopening of businesses after required closings and economic uncertainty,[6] none of these witnesses acknowledge the benefits in economic activity that the Company's capital program has had and will have within the Company's service territory and throughout Pennsylvania. Specifically, the Company is currently expending

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1 *See, e.g.*, OCA Statement No. 1, p. 3.

2 OCA Statement No. 4, p. 3. While Messrs. Rubin and Mierzwa recommend no rate increase, OCA witness David Efron calculates a revenue deficiency, although Mr. Efron states that this should not be interpreted to mean that he believes that any calculated revenue deficiency should result in a rate increase to customers because of his position that the projected rate base and expenses are speculative due to the uncertainty surrounding the pandemic. (OCA Statement 2, p. 4).

3 CAUSE-PA Statement No. 1, p. 7.

4 CAAP Statement No. 1, pp. 2-3, 8.

5 CII Statement No. 1, pp. 9-10.

6 OCA Statement No. 1, pp. 9, 12, 27; OCA Statement No. 4, p. 3, CAAP Statement 1, p. 2; CAUSE PA Statement p. 7; CII Statement No. 1, p. 9.

capital associated with the 2020 Future Test Year (*i.e.*, the 12 months ending November 30, 2020), and is proposing a number of capital expenditures during the 2021 Fully Projected Test Year (*i.e.*, the 12 months ending December 31, 2021)[7] as part of its application in this proceeding, including required capital expenditures associated with its Second Long-Term Infrastructure Improvement Plan ("LTIIP")[8] (collectively, the capital expenditures in 2020 and 2021 will be referred to as the "Capital Projects").[9] As a result, and in order to provide the Commission with a more complete record on this issue, my rebuttal testimony estimates the gross regional economic benefits that will result from the Company's expenditures associated with the Capital Projects, which are in addition to the safety, reliability, quality of service, and direct customer financial benefits (*e.g.*, the value of access to relatively low cost natural gas versus other fuel alternatives) of those expenditures.[10]

Q. Are you sponsoring any exhibits other than Exhibit TB-1 previously mentioned?

A. No.

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7 Colombia Statement No.1, p. 11 (Figure 1); Columbia Statement No. 2, p. 2.

8 *Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan*, Docket Number Docket Nos. P-2017-2602917 / P-2012-2338282 (September 21, 2017).

9 The capital expenditures modeled reflect actual expenditures through July 2020, and projected expenditures thereafter through December 2021.

10 The gross economic impacts evaluated herein focus on the economic stimulus resulting from the spending on the Capital Projects rather than effects associated with their operation or the recovery of the investments.

II. SUMMARY OF CONCLUSIONS

Q. Please summarize the key conclusions of your rebuttal testimony.

A. Based on an independent analysis of the economic impacts of the Company's proposed Capital Projects on the local economy, I conclude the following:

- While witnesses Rubin, Mierzwa, Miller, Moore and Plank recommend that now is not the time for a rate increase based on difficult economic circumstances, they have not considered the economic benefits associated with the Company's proposed Capital Projects, although Ms. Moore and Mr. Miller acknowledge the benefits associated with other spending activity by the Company, including funding of low-income assistance programs.
- The proposed Capital Projects represent a substantial injection of investment dollars into the local economies in the Company's service territory that will promote economic activity, support jobs and generate tax revenues, thus providing important economic stimulus to Pennsylvania communities that have been negatively impacted by the pandemic, and help mitigate the unemployment and other concerns raised by witnesses Rubin, Mierzwa, Miller, Moore and Plank. The majority of the proposed investment dollars in 2020 and 2021 (*i.e.*, a total of $561.1 million) relate to required pipe replacement and betterment projects associated with the Company's program of accelerated replacement of older pipe to enhance the safety and reliability of service to the Company's customers.
- The economic benefits that the Capital Project spending would produce within the Company's service territory specifically, and to Pennsylvania more generally, are wide-ranging and substantial. Specifically, on a combined basis for 2020 and 2021:
    - The Company's investments associated with the Capital Projects are expected to generate $922.8 million in overall economic activity in the Company's service territory, with an incremental $65.3 million elsewhere in Pennsylvania.
    - This economic activity generated by the Capital Projects would create approximately $476.5 million in incremental gross regional product in the service territory, and an additional $34.5 million elsewhere in Pennsylvania.
    - This economic activity also includes $35.8 million in additional state and municipal tax revenue for local communities within the Company's service territory over the two years.
    - Furthermore, the economic activity associated with the Capital Projects is expected to support 3,683 jobs in 2020 and 4,247 jobs in 2021 within the Company's service territory.

- These economic benefits are especially important to consider during this period when the economy has been negatively impacted by the pandemic and has begun the process of reopening.

III. ECONOMIC IMPACT ANALYSIS

A. Economic Impacts

Q. Witnesses Rubin, Mierzwa, Miller, Moore and Plank state that the prevailing economic conditions in the Company's service territory should lead the Commission to deny the Company's requested rate increase.[11] How do you respond?

A. While these witnesses discuss the recent economic impacts and uncertainty caused by the pandemic to support their recommendations, largely focusing on unemployment and business closures or reduced operations,[12] none of these witnesses attempt to quantify the effects that the Company's capital program, which is supported by the proposed rate increase, would have on current economic conditions within its service territory. These witnesses overlook that the Capital Projects proposed by the Company contain significant investments that will drive economic activity within the service territory and throughout Pennsylvania, including in particular, supporting the creation and maintenance of jobs. This capital spending coincides with the impacts caused by the pandemic and will help

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[11] *See, e.g.,* OCA Statement No. 1, p. 27 ("Moreover, given the current economic situation, I conclude that it is neither just nor reasonable to increase rates to Columbia's customers at this time."); OCA Statement No. 4, p. 3 ("In addition, as a result of the COVID-19 pandemic, it would not be just or reasonable to impose a rate increase at this time when unemployment numbers are close to record-highs and the economic effects of the pandemic will not be fully known for some time. Therefore, the Commission should deny [Colombia] any rate increase in this proceeding.."); CAUSE-PA Statement 1, p. 7 ("Thus, until we can more precisely understand the economic impact of the pandemic on local communities and individuals, I do not believe it is appropriate for the Commission to approve any increase in rates."); CAAP Statement No. 1, pp. 2-3 ("Although most counties in Pennsylvania have resumed most economic activities there remains limits on significant sectors of our economy. [. . .] I do not believe that any rate increase should be granted."); CII Statement No., 1, pp. 9-10 ("I suggest that the PUC deny Columbia's requested rate increase at this time. [. . .] If, however, the PUC allows Columbia to increase its rates at this time, I would ask that the PUC significantly limit any rate increase to the Rate LDS class.").

[12] *Id*.

stimulate the local economies underlying much of the discussion in the testimonies of witnesses Rubin, Mierzwa, Miller, Moore and Plank that are the basis for their recommendations that the Company should not have a rate increase in this proceeding.

Q. Do witnesses Rubin, Mierzwa, Miller, Moore or Plank recognize economic benefits associated with the Company's spending?

A. Yes. While these witnesses do not quantify the benefits associated with the Company's capital spending program, Ms. Moore notes in her testimony the benefits from expanding the Low Income Usage Reduction Program ("LIURP") for weatherization services,[13] as does Mr. Miller.[14] In addition, another OCA witness, Roger D. Colton, also acknowledges the positive economic effects on low-income customers of the Company's Customer Assistance Program ("CAP") and other assistance programs. Mr. Colton states that these programs provide customers with more dollars to spend in the local economies that helps, "drive additional job creation, income generation, and economic activity."[15]

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[13] CAAP Statement No. 1, pp. 6-7.

[14] CAUSE-PA Statement No. 1, pp. 29-31.

[15] OCA Statement No. 5, p. 48 ("As a significant contributor to economic development, low-income rate affordability programs provide substantive benefits to all customer classes. Because programs such as CAP contribute to income within the low-income population that can be spent in the general retail economy (on items such as food and clothing), it helps drive additional job creation, income generation, and economic activity.")

Q. Are the current unemployment levels and restriction of economic activity for many local businesses resulting from the pandemic shutdowns in Pennsylvania generally and in the Columbia Gas's service territory specifically the only factors that should be considered regarding the Company's proposed rate increase?

A. No. Clearly, unemployment in Pennsylvania and elsewhere throughout the United States is high, and many individuals are facing extremely difficult financial challenges. However, the Company's expenditure of significant investment dollars will drive economic activity, lead to increased tax revenue and support numerous jobs in the local communities at a time in which such economic activity is extremely important. These economic benefits to the local communities in the Company's service territory and throughout Pennsylvania are in addition to the improvements in safety, reliability and operations that would also result from the proposed Capital Projects.

B. IMPLAN Analysis

Q. Did you perform an analysis to quantify the economic impacts associated with the investment related to the Capital Projects?

A. Yes. In order to evaluate the economic impacts associated with the Company's planned capital investments, I modeled the effects of the Capital Projects on the Company's service territory and on the Pennsylvania economy overall using a macroeconomic input/output ("I/O") model developed and maintained by IMPLAN Group LLC ("IMPLAN"). IMPLAN is a widely recognized I/O modeling platform used by various government agencies, universities, and public and private sector organizations for assessing the economic impacts of project decisions across numerous industries.

Q Could you please provide a brief description of IMPLAN?

A. IMPLAN models the impact of investments and spending programs on the economies within which the investments and spending take place. IMPLAN analyzes how dollars injected into one sector of the economy are subsequently spent and re-spent in other sectors, generating what is known as economic multiplier effects that demonstrate how spending and investments flow within an economy. Using actual historical spending patterns of households, businesses and government agencies, IMPLAN is able to model an economic "event" (*e.g.*, an expenditure leading to the production of goods or services) to analyze how and where the dollars associated with that event will be spent. IMPLAN estimates the economic impact of the event for the specified regional economy in terms of both economic output and employment supported by the economic output.

Q. What is the data in the IMPLAN model that is used for your economic analysis?

A. For the analysis, I have used the most recent data available from IMPLAN, which is from 2018.[16] Since economic data are available at both the county level and state level, for purposes of this analysis, I have evaluated the economic impacts of the expenditures associated with the Company's proposed Capital Projects for both Colombia Gas's service territory within Pennsylvania (*i.e.*, 26 counties), as well as for the state as a whole.

[16] IMPLAN relies on historic data from public sources that is reported on a trailing basis. The 2019 data will be released in the fourth quarter of 2020.

Q. Does IMPLAN assume that all of the dollars that are expended related to a specific economic event provide economic benefits within the region being evaluated?

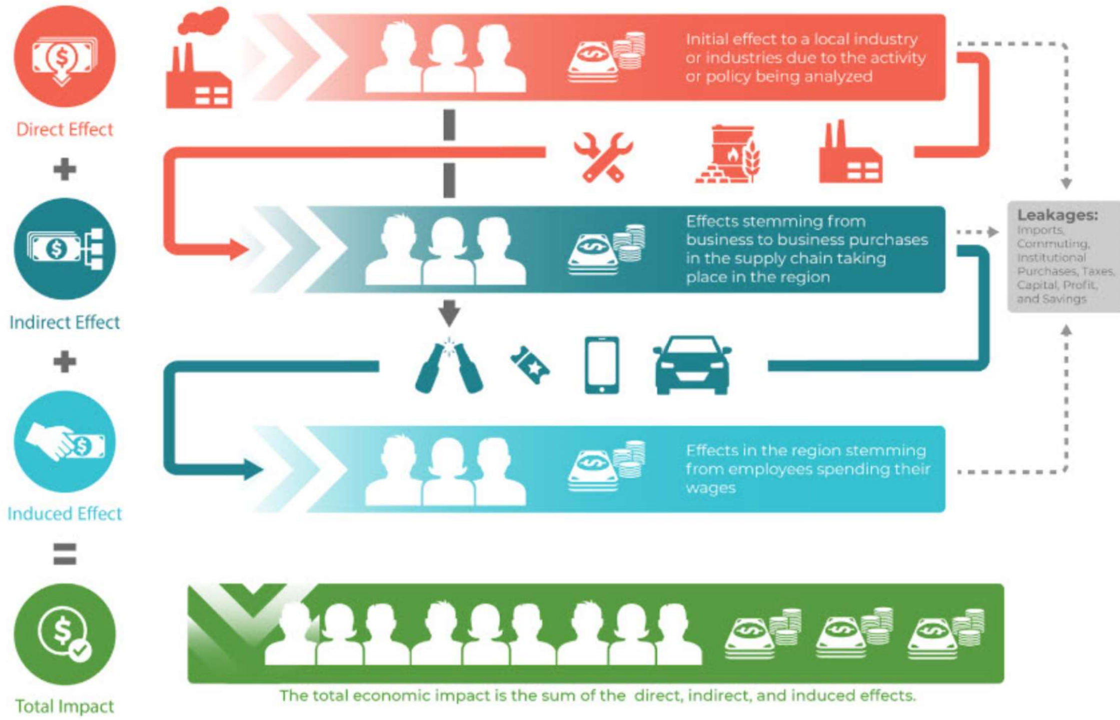
A. No. The model recognizes that not all dollars associated with a project will be re-spent in the region that is being studied as a result of what is termed "leakage." The term leakage refers to the fact that a portion of these dollars will be either saved by households and businesses or spent on goods and services produced outside of the study region. In subsequent rounds of spending, income generated will also be taxed at the federal level, resulting in another source of leakage. In essence, the model assumes a portion of the dollars injected into the economy will not contribute to overall economic activity in the region being evaluated as a result of these leakages.[17]

Q. What types of economic impacts does IMPLAN capture?

A. For a particular event, IMPLAN categorizes the economic effects of dollars injected into an economy as either direct effects, indirect effects, or induced effects. The direct effects result from an economic event being modeled and will then also lead to indirect and induced effects in the local economy being studied. These economic impacts in IMPLAN are summarized in Figure 1 below.

[17] While not part of this analysis, it is my understanding that there are large capital expenditure programs similar to Colombia Gas's being undertaken by other utilities in Pennsylvania, and leakages associated with the expenditure of dollars related to those programs would also provide a benefit to the businesses and households within Colombia Gas's service territory just as the leakage dollars associated with the Company's Capital Projects provide benefit elsewhere in Pennsylvania outside of the Columbia Gas service territory.

<u>Figure 1</u>: Overview of Economic Impacts Captured in IMPLAN



Q. Please further describe the "direct effects" in IMPLAN.

A. Direct effects are the economic impacts resulting from dollars spent directly in the local economy as a result of an economic event (*e.g.*, a construction project). The direct effects represent the dollar value of production changes or expenditures made by producers and consumers as a result of a financial stimulus. In this case, the direct effects refer to the economic activity generated from the Company's investments in goods and services within the study region related to the Capital Projects.

Q. What are considered the "indirect effects" in IMPLAN?

A. The indirect effects are defined as the supply chain, inter-industry or business-to-business impacts resulting from the direct effects of an economic event. In other words, beyond the direct effect of dollars being injected into an economy, there is also an indirect economic effect associated with the incremental economic activity resulting from subsequent spending by businesses in the local economy to produce additional goods and services to meet the demand created by the direct spending. In this case, the indirect impacts are the economic effects resulting from subsequent rounds of spending by the businesses within the regional economy from whom goods or services are purchased by the businesses that received the direct effects associated with the initial dollars invested by the Company associated with the Capital Projects.

Q. What are considered the "induced effects" in IMPLAN?

A. The induced effects, which are also referred to as income effects, are defined as the economic impacts of household spending resulting from either the direct or indirect impacts in the economy in the study region being evaluated. In other words, the induced effects relate to the spending of wages earned by the individuals holding jobs supported by the direct and indirect economic effects resulting from an economic event.

Q. Please describe your approach to modeling the economic impact of the Company's proposed Capital Projects.

A. The Company's projected expenditures for the Capital Projects is the primary input for the economic impact analysis. For modeling, the Capital Projects and associated spending are organized into the same five categories, by type of activity, as discussed in the Company's rate filing, and each category of spend is modeled as a separate economic event. These categories of capital projects, as identified in Colombia Gas's response to GAS-ROR-014, can generally be described as follows:

1. *Age & Condition/Replacement* – the capital expenditures associated with the replacement of existing mains and services, mitigating corrosion, regulation, and the replacement of low pressure pipe.
2. *Betterment* – the capital expenditures associated with mains installed to increase the capacity of existing lines and those that required replacement for compliance purposes.
3. *Growth* – the capital expenditures associated with mains, services, meters, regulators, and excess pressure measuring stations designed to serve new load.
4. *Public Improvement* – the capital expenditures associated with main relocations requested by third parties.
5. *Support Services* – the capital expenditures associated with tools and equipment for operations and construction, including communications equipment.

In addition, the Company has projected capital expenditures for projects associated with information technology ("IT") and a new operations center in Uniontown, Pennsylvania. Grouping the projects by major category reasonably balances the need to model the impacts of hundreds of individual projects and treating projects with similar characteristics as a single aggregated capital expenditure.

Q. Did you make any adjustments to the Company's projected expenditures associated with the Capital Projects?

A. Yes. Based on discussions with the Company regarding the capital spending, I reduced the expenditures for 2020 and 2021 associated with the Capital Projects that are estimated to be spent on goods and/or services outside of Pennsylvania. For example, the materials costs associated with the pipe replacement, betterment and growth categories represent a significant portion of the Company's total capital budget in those categories. Based on discussions with the Company, it is my understanding that none of the plastic or steel pipe will be manufactured in Pennsylvania, but rather elsewhere in the United States. Thus, for purposes of my analysis, I have excluded the pipe material costs associated with the Capital Projects on the assumption that the related production would occur outside of Pennsylvania.[18] Likewise, the Company's IT spending is related to the acquisition of hardware and software packages developed outside of Pennsylvania. While certain of the IT expenditures are labor-related that may occur within the Company's service territory, all of the expenditures associated with the IT projects are removed as an input for purposes of estimating the economic impacts of the Company's capital spend. Similarly, since the expenditures related to the Support Services largely consist of spending on tools and equipment presumedly manufactured outside of Pennsylvania, those expenditures are also removed for modeling purposes.

Q. Although you are excluding certain of the costs associated with the Capital Projects (*e.g.*, pipe material costs), are there still economic benefits that would result from these expenditures made by the Company?

A. Yes, there are still significant economic benefits associated with these expenditures that will occur elsewhere in the United States. For example, the manufacture of the pipe necessary to be installed within the Company's service territory will create economic

[18] The Company also reflects an allowance for funds used during construction ("AFUDC") as part of its construction projects. While the proportion of AFUDC relative to the total expenditures of the construction-related capital projects is very small (*i.e.*, less than 0.5%), these dollars are also excluded from the Capital Projects for purposes of the economic impact analysis since these are financing-related costs rather than construction spending.

benefits in the locations in those states where the pipe is manufactured. Because these economic benefits are outside of Pennsylvania, they have not been accounted for in my analysis; however, those dollars will help support jobs, tax revenues and increased economic output in those other communities.[19] This economic activity serves to assist numerous individuals located outside of Pennsylvania continue their recovery from the negative impacts of the COVID-19 pandemic at their own local level.

Q. In terms of the Company's overall projected expenditures related to the Capital Projects, what is the largest aspect of that spending?

A. The largest portion of the Company's total Capital Project budget for 2020 and 2021 relates to the installation of new pipe, both as a result of the pipe replacement/betterment activities required of the Company, as well as meeting growth and providing new or upgraded gas distribution service to customers. The installation of new pipe represents the majority of the total estimated cost of the Capital Projects for 2020 and 2021, and of those expenditures, well over half are labor-related for both Company and outside contractor personnel.

Q. Are the dollars reflected in the economic impact analysis the same as the dollars that the Company has reflected in plant in service for rate purposes?

A. No, not necessarily. IMPLAN analyzes the economic effects from construction spending on a project and those benefits start to flow through the economic study region regardless of when the project is ultimately placed into service. For example, dollars may be spent

[19] Likewise, as noted previously, there will be economic benefits experienced within Colombia Gas's service territory associated with economic activity occurring elsewhere in Pennsylvania (*e.g.*, due to other utility capital programs) and outside Pennsylvania; however, the analysis herein does not model or account for such effects.

on a capital project that may take a number of months to complete before it is placed into service, but the dollars that are spent will have economic impacts regardless of the whether the project is completed and in-service. Therefore, for example, while a portion of the Company's projected capital spend in 2021 may be considered construction work in progress for rate purposes because it would not be placed into service within 2021, the dollars that are projected to be spent in 2021 are included in the economic impact analysis. Likewise, the capital investments that have already been spent in 2020, as well as those expenditures projected to be spent through the remainder of 2020, are also included in the economic impact analysis. Thus, the Capital Projects modeled reflect the dollars spent or to be spent by the Company in 2020 and 2021, not the dollars that are sought to be included as plant in service in the rate proceeding.

Q. What are the total expenditures associated with the Capital Projects that you reflect as an economic input to the IMPLAN model?

A. Currently, the Company has projected a total capital spend of approximately $314.6 million for 2020, which reflects actual expenditures through July 2020, and $375.6 million for 2021 associated with the Capital Projects.[20] After adjusting that total capital spend for the investments that are projected to be made on goods and services outside of Pennsylvania, a total spend of $206.9 million for 2020 and $245.8 million for 2021 is

[20] These total costs include the expenditures projected related to information technology and the new Unionville, Pennsylvania operations center.

assumed for purposes of modeling the economic impacts of those expenditures in the study region.

Q. Will the Company's projected spend related to the Capital Projects produce economic benefits for the regional economy?

A. Yes. The Company's projected expenditures related to the Capital Projects are expected to generate approximately $427.4 million and $495.4 million in economic activity in 2020 and 2021, respectively, within Columbia Gas's service territory in Pennsylvania. This economic activity generated by the capital expenditures would create approximately $220.4 million and $256.1 million in incremental gross regional product in the service territory, which includes approximately $16.6 million and $19.2 million in additional state and municipal tax revenue for local communities in the service territory in 2020 and 2021, respectively. Importantly, this economic activity associated with the Capital Projects is also expected to support approximately 3,683 and 4,247 jobs, respectively, in these same years.

There will also be additional economic benefits elsewhere in Pennsylvania outside of the Company's service territory associated with the Capital Projects. Specifically, the projected expenditures related to the Capital Projects are expected to generate $30.3 million and $35.0 million in increased economic activity elsewhere in Pennsylvania in 2020 and 2021, respectively. This economic activity generated by the Capital Projects is projected to create approximately $16.0 million and $18.5 million in incremental gross regional product elsewhere in Pennsylvania, which includes approximately $1.4 million in 2020 and

$1.6 million in 2021 in additional state and municipal tax revenue for local communities. Furthermore, this incremental economic activity associated with the Capital Projects is expected to support approximately 151 and 175 jobs elsewhere in Pennsylvania in these respective years.

The economic output and employment opportunities resulting from the expenditures associated with the Capital Projects are expected to occur predominantly in construction-related sectors since the largest portion of the investment dollars are related to pipe construction and other activities. As described by the Company's witness R.M. Kitchell, the magnitude of Columbia Gas's pipeline infrastructure replacement program is substantial, as the Company had, on average during 2019, approximately 140 construction crews that employed 1,400 contractor employees and subcontractors.[21]

The direct, indirect and induced economic effects for Columbia Gas's service territory and elsewhere in Pennsylvania are summarized in Figure 2.

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[21] Columbia Gas of Pennsylvania, Statement No. 14, p. 21.

Figure 2: **Summary of Economic Impacts of the Company's Capital Projects**

	Economic Output	Gross Regional Product	State/Local Tax Revenue	Jobs Supported
Colombia Gas Service Territory				
Calendar Year 2020	$ 427,426,350	$ 220,402,158	$ 16,613,240	3,683
Calendar Year 2021	$ 495,399,539	$ 256,054,655	$ 19,189,381	4,247
Total	$ 922,825,889	$ 476,456,812	$ 35,802,620	7,929
Outside Colombia Gas Service Territory/Within PA				
Calendar Year 2020	$ 30,293,538	$ 16,004,425	$ 1,400,898	151
Calendar Year 2021	$ 35,028,852	$ 18,500,904	$ 1,618,357	175
Total	$ 65,322,390	$ 34,505,328	$ 3,019,255	327
Pennsylvania Overall				
Calendar Year 2020	$ 457,719,888	$ 236,406,582	$ 18,014,137	3,834
Calendar Year 2021	$ 530,428,391	$ 274,555,558	$ 20,807,738	4,422
Total	$ 988,148,279	$ 510,962,141	$ 38,821,875	8,256

Q. Would a similar level of economic benefits as shown in Figure 2 be expected to result from the Company's future capital expenditures associated with continued work associated with the Second LTIIP?

A. Yes, assuming that the extent of the Company's capital spend in the future is similar to the investment spending evaluated for 2020 and 2021, then it would be expected that a similar magnitude of economic benefits would result each year over the remaining years of the Second LTIIP and any future expenditures beyond that period.

Q. Previously, you indicated that the most recent data available in IMPLAN was as of 2018. Have you made any adjustments to your analysis for the effects of the COVID-19 pandemic?

A. The shifts in spending in the economy that have occurred due to the COVID-19 pandemic, whether temporary or permanent, are not currently fully known. However, there are sectors of the economy that have clearly experienced a reduction in consumer spending due to the required government shutdowns (*e.g.*, restaurants; travel-related sectors such as airlines, hotels, rental cars; and entertainment facilities). Likewise, there have been other sectors of the economy that have likely experienced significant increases in consumer spending (*e.g.*, online purchases; groceries; home delivery services; home improvement/gardening). For purposes of the analysis, since it is not known at the current time how spending patterns will be changed by the pandemic, I have not made any specific assumptions as to changes in spending patterns in the economy.

IV. <u>CONCLUSION</u>

Q. What are your conclusions regarding the testimony of witnesses Rubin, Mierzwa, Miller, Moore and Plank relative to the economic impacts they discuss in their testimonies and their resulting recommendations?

A. While these witnesses state that now is not the time for Columbia Gas to implement a rate increase based on prevailing difficult economic circumstances, they have not considered the economic benefits associated with the Company's proposed Capital Projects, although Mr. Miller and Ms. Moore acknowledge the benefits associated with other economic activity in the community, including from the Company funding low-income assistance programs. The economic benefits that the Capital Projects – the majority of which are required to maintain the safety and reliability of the distribution system – would produce within the Company's service territory specifically, and to Pennsylvania more generally, are wide-ranging and substantial. The proposed Capital Projects represent a substantial injection of investment dollars into the local economies that will promote economic activity, support jobs and generate tax revenues, thus providing important economic stimulus to Pennsylvania communities that have been negatively impacted by the pandemic, and help mitigate the unemployment and other concerns raised by witnesses Rubin, Mierzwa, Miller, Moore and Plank.

Q. Are you recommending that the proposed rate increase should be approved due to the economic benefits that the Capital Projects would have on the local economies within the Company's service territory and in Pennsylvania as a whole?

A. No, the purpose of my testimony is not to recommend that the Commission approve a rate increase associated with the Capital Projects due to the modeled economic benefits that those expenditures would provide. Rates are typically established based on prudently-incurred costs, among other ratemaking considerations, not on the level of economic benefits associated with certain activity. As discussed, the majority of the expenditures associated with the Capital Projects relate to the Company's Second LTIIP, which provides for the replacement of older pipe that will enhance the safety and reliability of the distribution system for all customers, regardless of the economic benefits of such expenditures in the local economy. Rather, I am pointing out that the proposals from witnesses in this proceeding that recommend the Company should receive no rate increase due to the effects of the pandemic are incomplete and do not consider the positive impacts that the Company’s capital program will have on the local economies within its service territory and more broadly throughout Pennsylvania.

Q. Does this conclude your rebuttal testimony?

A. Yes.

TOBY BISHOP
Senior Vice President

Mr. Bishop has over 25 years of management and economic consulting experience advising energy industry clients throughout the United States and Canada. Mr. Bishop has a broad range of experience covering strategic, regulatory, financial, and transactional matters. Specifically, Mr. Bishop has extensive regulatory and civil litigation experience regarding both natural gas and electric issues, including federal and state rate case proceedings, market power and competitive concerns, asset purchase and sales transactions, contractual disputes, regulatory strategy and policy formulation. In addition, Mr. Bishop has assisted numerous clients throughout North America evaluate energy markets for purposes of regulatory filings, due diligence for acquisitions and divestitures, market entry/exit and competitive assessments, and asset valuation. Mr. Bishop has testified before the Federal Energy Regulatory Commission, the National Energy Board, the Canada Energy Regulator, the Nova Scotia Utility and Review Board, and the British Columbia Utilities Commission.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)

REED Consulting Group/Navigant Consulting, Inc. (1995 – 2002)

Fleet National Bank (1993 – 1995)

EDUCATION

Colgate University
B.A., Economics and Geography

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory and Litigation Representation/Support

Extensive experience in the research, analysis, preparation and defense of expert testimony, reports, affidavits and other filings in over 50 administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included natural gas distribution companies, natural gas pipelines, natural gas storage providers, natural gas producers, electric utilities, and independent energy project developers. Testimony has focused on issues ranging from broad regulatory and economic policy, valuation for damages assessment, and management prudence, to virtually all elements of the utility ratemaking process, including cost of service, cost allocation, rate design, and cost of capital. Representative engagements have included:

- Strategic analysis for a large energy company considering alternatives for its existing pipeline and storage portfolio.

- Development of a financial model and assist in the transaction structuring for a natural gas storage developer seeking to construct and then sell a storage facility to an LDC in the western half of the U.S.
- Litigation support for the Upper Midwest Shipper Group on all aspects the Northern Natural RP19-1353 rate case proceeding.
- Litigation support for the WEC Energy Group on all aspects the Great Lakes Gas Transmission RP17-593 rate case proceeding.
- Litigation support for the Upper Midwest Distributor Group on all aspects of the Natural Gas Pipeline Company of America RP17-303 rate case proceeding.
- Litigation support, including the drafting of a reply expert report, relating to a $500 million claim associated with the value of Ultra Petroleum Corp. exiting bankruptcy.
- Litigation support for the Upper Midwest Distributor Group on all aspects of the ANR Pipeline RP16-440 rate case proceeding.
- Litigation support, including the drafting of expert reports, on behalf of Mitsubishi Heavy Industries regarding a $7.5 billion claim in an international arbitration proceeding regarding damages associated with the SONGS 2 and 3 nuclear facilities.
- Evaluation of potential market power and competitive concerns on over 25 occasions for leading North American energy companies covering both natural gas and electric issues. Engagements have included the preparation of independent market power analyses and supporting testimony in association with proposed mergers and market-based rate applications for underground natural gas storage facilities throughout the U.S. and Canada. These engagements have included the filing of testimony before the Federal Energy Regulatory Commission and the British Columbia Utilities Commission.
- Cost allocation and rate design witness providing ongoing litigation support on behalf of Arizona Public Service in El Paso Natural Gas Company's two most recent FERC rate cases.
- Extensive litigation support to TransCanada PipeLines before the National Energy Board, including major proceedings regarding its Mainline pipeline restructuring, changes in services, abandonment cost recovery and its comprehensive settlement to transition to a new tolling regime.
- Litigation support before the Alberta Energy Regulatory (formerly Energy Resources Conservation Board), on behalf of CrossAlta Gas Storage regarding public interest issues related to natural gas storage in a case in which an oil producer was seeking to drill through the CrossAlta storage reservoir.
- Preparing multiple rounds of testimony in support of a group of utilities, including Oncor, AEP and MidAmerican Energy, seeking to construct over $5 billion of new transmission in Texas as part of the state's Competitive Renewable Energy Zone process.

- Litigation support to NOVA Gas Transmission Ltd. in multiple proceedings regarding the development and tolling of new facilities in British Columbia and Alberta.
- Preparing expert reports and providing litigation support to Boston Edison regarding its damages claims against the Department of Energy relating to spent nuclear fuel for Pilgrim nuclear generating station.
- Assisting ONEOK Partners in the development and implementation of two new off-system storage services for its Guardian Pipeline, including the development of the open season process for these new services, the pro forma tariff, forms of service agreement, precedent agreements between Guardian and its customers, and rate design for the new services.
- Preparation of an expert report on behalf of Merrill Lynch assessing and quantifying damages in its litigation regarding the sale of its energy trading business.
- Providing litigation support to Missouri Gas Energy to defend against proposed gas purchase disallowances for storage utilization, hedging activity and capacity release decisions.
- Providing ongoing regulatory oversight and litigation support to the Northern Distributor Group, a group of 13 local distribution companies (LDCs) in the Midwest served by Northern Natural Gas Company in FERC rate, certificate, and other regulatory matters. Included drafting testimony, comments, interventions and various other regulatory filings to be filed with the FERC.

Market Assessment

Retained by numerous leading domestic and international energy companies to provide assessments of energy markets throughout the United States. Such assessments have included evaluation of electric and natural gas supply issues, development of projected electric and natural gas demand, viability/feasibility of infrastructure projects including numerous analyses regarding underground storage, LNG and electric generation, analysis of gas commodity price trends, assessment of existing and projected natural gas and electric transmission infrastructure, market structure, regulatory issues, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of asset-specific strategic plans, regulatory initiatives or valuation analyses. Many of the projects have been supported by the filing of expert reports with the FERC, the National Energy Board (NEB), and state regulatory agencies. Representative engagements have included:

- Preparation of a report on behalf of the proposed Adelphia Gateway pipeline regarding the potential energy and economic benefits to natural gas and electric consumers in the Greater Philadelphia region.
- Preparation of multiple reports on behalf of the proposed PennEast Pipeline regarding the potential economic benefits of the pipeline to natural gas and electric customers in the Mid-Atlantic region, including rebuttal comments addressing issues raised by opponents of the pipeline.

- Preparing numerous assessments of the natural gas and electric markets in eastern Canada, Atlantic Canada, and the northeastern and mid-Atlantic United States for various energy companies seeking to enter the market and/or expand existing operations in the market.
- Preparing a detailed demand and supply analysis of the opportunity for underground natural gas storage in the Mid-Atlantic and upper Midwest markets.
- Evaluating the opportunity for the development of a new underground storage facility in the southeastern United States. The project included preparing a detailed report for the client that included the future market opportunity that could be achieved from the facility.
- Preparing a detailed demand/supply and risk analysis of an existing natural gas storage project in the Eastern U.S. for a commercial bank seeking to finance a partnership buyout of the facility.
- Evaluating the market opportunity for LNG in the northeastern United States for a client seeking to develop an LNG facility import terminal. The project included reviewing future demand/supply in the region and competing supplies.

Valuation

Significant experience utilizing various valuation methodologies to value generation assets for strategic planning, tax, financing and other purposes. Methodologies utilized have included discounted cash flow, comparable sales, replacement and reproduction cost. Have prepared expert reports, testimony and certifications for use before federal and state regulatory proceedings, taxing authorities, financial institutions and boards of directors. Representative engagements have included:

- Preparation of feasibility studies evaluating the costs and benefits of the potential municipalization of existing electric utility systems in multiple states.
- Valuation of the electric transmission and distribution property of numerous investor-owned and electric cooperative utilities.
- Valuation of property of a telecommunications provider in three communities in New Hampshire for property tax purposes.
- Valuation of numerous electric generation facilities (*e.g.,* coal-fired; gas-fired; run-of-river hydroelectric; biomass; pumped storage) for property tax purposes.
- Valuation of peak shaving and import LNG facilities.
- Valuation of a combined cycle electric generating facility in Florida for purposes of a fairness opinion issued by Concentric's subsidiary, CE Capital Advisors, Inc.
- Valuation of Northern Indiana Public Service Company's generation, transmission and distribution assets as part of an electric rate proceeding.
- Valuation of certain FirstEnergy generation facilities for the release of a bond indenture.

Mergers, Acquisitions and Divestitures

For numerous leading energy companies, have assisted in the acquisition and divestiture of over $5 billion in energy assets, including providing strategic advice, detailed due diligence and project management relating to a variety of regulated and non-regulated energy projects. Representative engagements have included:

- The sales of the Point Beach, Palisades and Duane Arnold nuclear generating facilities.
- The divestitures of the generating fleets of Boston Edison, GPU and Potomac Electric Power.
- Assisting a large energy company evaluate and value a potential natural gas storage acquisition in the western United States.
- Assisting a large North American pipeline company evaluate its positioning in the market, including a review of issues such as cost of service, cost allocation, rate design, trading points and new service alternatives for its pipelines.
- Confidential buy-side valuation and assessment of a regulated combination electric and natural gas utility in the Northeastern U.S.
- Confidential buy-side valuation and assessment of a regulated combination electric and natural gas utility in New York.

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Federal Energy Regulatory Commission				
Northern Distributor Group	10/98	Northern Natural Gas Company	Docket No. RP98-203	Cost Allocation
Central New York Oil & Gas Company, LLC	2/06	Central New York Oil & Gas Company, LLC	Docket No. CP06-64-000	Market Power
Central New York Oil & Gas Company, LLC	10/07	Central New York Oil & Gas Company, LLC	Docket No. CP06-64-001	Market Power
Chestnut Ridge Storage, LLC	12/07	Chestnut Ridge Storage, LLC	Docket No. CP08-36	Market Power
Arlington Storage Company, LLC	3/08	Arlington Storage Company LLC	Docket No. CP08-96	Market Power
Worsham-Steed Gas Storage, LP	5/08	Worsham-Steed Gas Storage, LP	Docket No. PR08-23	Market Power
Arizona Public Service Company	5/09	El Paso Natural Gas Company	Docket No. RP08-426	Cost Allocation/ Rate Design
Arizona Public Service Company	7/09	El Paso Natural Gas Company	Docket No. RP08-426	Cost Allocation/ Rate Design
Arizona Public Service Company	8/09	El Paso Natural Gas Company	Docket No. RP08-426	Cost Allocation/ Rate Design
UGI Storage Company	11/09	UGI Storage Company	Docket No. CP10-23	Market Power
Magnum Gas Storage, LLC	11/09	Magnum Gas Storage, LLC	Docket No. CP10-22	Market Power
East Cheyenne Gas Storage, LLC	1/10	East Cheyenne Gas Storage, LLC	Docket No. CP10-34	Market Power
Petal Gas Storage, LLC	1/10	Petal Gas Storage, LLC	Docket No. CP10-50	Market Power
UGI Storage Company	2/10	UGI Storage Company	Docket No. CP10-23	Market Power
Arizona Public Service Company	3/10	El Paso Natural Gas Company	Docket No. RP08-426	Rate Design
Arlington Storage Company, LLC	3/10	Arlington Storage Company LLC	Docket No. CP10-99	Market Power
Tallulah Gas Storage, LLC	8/10	Tallulah Gas Storage, LLC	Docket No. CP10-494	Market Power
Rager Mountain Storage Co. LLC	10/10	Rager Mountain Storage Co. LLC	Docket No. CP11-5	Market Power
Central New York Oil & Gas Company, LLC	3/11	Central New York Oil & Gas Company, LLC	Docket No. CP10-194	Market Power

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Federal Energy Regulatory Commission				
Rager Mountain Storage Co. LLC	3/11	Rager Mountain Storage Co. LLC	Docket No. CP11-5	Market Power
Arizona Public Service Company	6/11	El Paso Natural Gas Company	Docket No. RP10-1398	Cost Allocation/ Rate Design
Arizona Public Service Company	8/11	El Paso Natural Gas Company	Docket No. RP10-1398	Cost Allocation/ Rate Design
UGI Storage Company	8/11	UGI Storage Company	Docket No. CP11-542	Market Power
Central New York Oil & Gas Company, LLC	2/12	Central New York Oil & Gas Company, LLC	Docket No. CP10-194	Market Power
Worsham-Steed Gas Storage LLC	5/12	Worsham-Steed Gas Storage LLC	Docket No. PR07-6	Market Power
Rager Mountain Storage Co. LLC	1/14	Rager Mountain Storage Co. LLC	Docket No. CP13-139	Market Power
PennEast Pipeline Company, LLC	9/15	PennEast Pipeline Company, LLC	Docket No. CP15-558	Mkt. Conditions/Need
Magnum Gas Storage, LLC	11/15	Magnum Gas Storage, LLC	Docket No. CP16-18	Market Power
PennEast Pipeline Company, LLC	4/16	PennEast Pipeline Company, LLC	Docket No. CP15-558	Mkt. Conditions/Need
PennEast Pipeline Company, LLC	10/16	PennEast Pipeline Company, LLC	Docket No. CP15-558	Mkt. Conditions/Need/ Rate of Return
Costco Wholesale Corp.	1/17	Tricon Energy Ltd. and Rockbriar Partners Inc. v. Colonial Pipeline Company	Docket No. OR16-17	Petroleum/Refined Products Pipeline Capacity Prorationing
Laclede Gas Company	1/17	Spire STL Pipeline, LLC	Docket No. CP17-40	Mkt. Conditions/Need
East Cheyenne Gas Storage, LLC	11/17	East Cheyenne Gas Storage, LLC	Docket No. CP18-11	Market Power
Spire Storage West, LLC	7/18	Spire Storage West, LLC	Docket No. CP18-520	Market Power
Washington 10 Storage Corp.	5/20	Washington 10 Storage Corp.	Docket No. CP20-470	Market Power

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Pennsylvania Public Utility Commission				
UGI Utilities, Inc.	6/20	UGI Utilities, Inc.	Docket No. R-2019-3015162	Economic Impacts
National Energy Board of Canada				
TransCanada PipeLines Ltd.	12/13	TransCanada PipeLines Ltd.	MH-1-2013	Cost Allocation
NOVA Gas Transmission Ltd.	10/17	NOVA Gas Transmission Ltd.	MH-031-2017	Tolling Policy for New Facilities
NOVA Gas Transmission Ltd.	12/17	NOVA Gas Transmission Ltd.	MH-031-2017	Tolling Policy for New Facilities
NOVA Gas Transmission Ltd	3/19	NOVA Gas Transmission Ltd	RH-001-2019	Rate Design / Tolling Policy for New Facilities
Canada Energy Regulator				
NOVA Gas Transmission Ltd	11/19	NOVA Gas Transmission Ltd	RH-001-2019	Rate Design / Tolling Policy for New Facilities
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	6/19	Nova Scotia Power Inc.	M09273	Contracting Prudence/ Mkt. Conditions
British Columbia Utilities Commission				
Unocal Canada Limited	10/06	Unocal Canada Limited	Project No. 3698445	Market Power

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September 21, 2020

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-2020-3018835

Dear Secretary Chiavetta:

Enclosed is the Stipulation Between Columbia Gas of Pennsylvania, Inc. and The Bureau of Investigation and Enforcement for filing in the above-referenced proceeding. Copies will be provided as indicated on the Certificate of Service.

Respectfully submitted,

Lindsay A. Berkstresser

Lindsay A. Berkstresser

LAB/jl
Enclosures

cc: Certificate of Service
Honorable Katrina L. Dunderdale

CERTIFICATE OF SERVICE
(R-2020-3018835)

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant.)

VIA E-MAIL ONLY

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Consultant for OSBA

Dr. Richard Collins
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State College, PA 16801
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James L. Crist
4226 Yarmouth Drive
Suite 101
Allison Park, PA 15101
jlcrist@aol.com

Date: September 21, 2020

Lindsay A. Berkstresser

____
Lindsay A. Berkstresser

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018835
	:	
Columbia Gas of Pennsylvania, Inc.	:	

STIPULATION BETWEEN COLUMBIA GAS OF PENNSYLVANIA, INC. AND THE BUREAU OF INVESTIGATION AND ENFORCEMENT

Columbia Gas of Pennsylvania, Inc. ("Columbia") and the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission") hereby stipulate as follows:

1. On July 28, 2020, I&E submitted I&E Exhibit No. 1 to accompany the Direct Testimony of John Zalesky. I&E Exhibit No. 1 contains a copy of the Commission's General Assessments Invoice to Columbia dated September 9, 2019.

2. Attached to this Stipulation as Columbia Exhibit No. NJDK-1RJ is a true and correct copy of the Commission's General Assessments Invoice to Columbia dated September 10, 2020.

3. In lieu of submission of rejoinder by Columbia, and as part of the agreement to waive cross-examination between Columbia and I&E, Columbia intends to submit Exhibit No. NJDK-1RJ for the record at the evidentiary hearing in the above-captioned proceeding, and I&E agrees not to oppose such submission.

Date: 9/21/2020

Michael W. Hassell (ID # 34851)
Lindsay A. Berkstresser (ID # 318370)
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Phone: 717-233-1351
E-mail: ahirakis@nisource.com

For Columbia Gas of Pennsylvania, Inc.

Date: September 21, 2020

Erika L. McLain, Esquire
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
Harrisburg, PA 17120

For Bureau of Investigation and Enforcement

Columbia Exhibit No.
NJDK-1RJ

Commonwealth of Pennsylvania

Pennsylvania Public Utility Commission

Harrisburg, PA 17105-3265

GENERAL ASSESSMENTS INVOICE

Invoice Date	Invoice Number
9/10/2020	20-120700
Fiscal Year	
July 1, 2020 to June 30, 2021	

COLUMBIA GAS OF PA INC
ELIZABETH TAPP
290 W NATIONWIDE BLVD
COLUMBUS OH 43215

- Read carefully Notice of Assessment
- Use return envelope provided
- Make check payable to: **Commonwealth of Pennsylvania**
- If you desire confirmation of receipt, use a mailing service that provides one, such as USPS-Return Receipt, or overnight delivery with receipt confimation

PUC Assessment	$1,653,409.00
Consumer Advocate Assessment	$256,254.00
SBA Assessment	$88,600.00
DPC Assessment	$10,529.00
PAY THIS AMOUNT WITHIN 30 DAYS	**$2,008,792.00**

TO RECEIVE PROPER CREDIT FOR YOUR PAYMENT, REMOVE THE BOTTOM PART OF THIS INVOICE AT THE PERFORATION AND RETURN WITH YOUR REMITTANCE

MAIL PAYMENT TO:

PA DOR
PO BOX 61380
HARRISBURG, PA 17106-1380

FOLD AND CUT HERE

RETURN THIS PORTION WITH YOUR REMITTANCE

COLUMBIA GAS OF PA INC
ELIZABETH TAPP
290 W NATIONWIDE BLVD
COLUMBUS OH 43215

Invoice Date	Invoice Number
9/10/2020	20-120700
Fiscal Year	
July 1, 2020 to June 30, 2021	

PAY THIS AMOUNT WITHIN 30 DAYS	$2,008,792.00

200000120700081 0910201016639380020025625400300088600000 002008792002

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

NOTICE OF ASSESSMENT

EXPLANATION OF BILL FOR GENERAL ASSESSMENT FOR FISCAL YEAR JULY 1, 2020 TO JUNE 30, 2021

In Section 510 of the Public Utility Code, 66 Pa. C.S. §510, the Pennsylvania General Assembly has authorized the Pennsylvania Public Utility Commission to assess all public utilities a percentage of their gross intrastate operating revenues for the preceding calendar year. Under Section 510, each public utility is required, on or before March 31 of each year to file with the Commission a statement of the utility's gross intrastate operating revenues for the preceding calendar year. After receiving the utilities' statements of gross intrastate operating revenues, the Commission sends general assessment invoices to all public utilities to advise each utility of the amount of assessment that utility owes based upon that utility's activity (gross intrastate operating revenues) in the preceding year. The enclosed assessment is for your proportionate share of the estimated expenses of the Public Utility Commission for the Commission's Fiscal Year July 1, 2020 to June 30, 2021.

YOU ARE REQUIRED TO PAY THIS BILL WITHIN THIRTY DAYS AFTER YOU RECEIVE IT. Objections to the assessment must be made in writing within 15 days and shall set out in detail the grounds upon which you regard the assessment to be excessive, erroneous, unlawful, or invalid. Objections may be filed only by the person, partnership, or corporation assessed. Filing an objection, however, does not eliminate your obligation to pay the assessment while your objection is being considered. **FAILURE TO PAY THE ASSESSMENT WHEN PAYMENT IS DUE WILL SUBJECT YOU TO PENALTIES.**

Be sure that your personal check or money order is written out in the same amount as your assessment invoice, and make your remittance payable to, "Commonwealth of PA". DO NOT SEND CASH. If you have reason to correspond with the Commission regarding your assessment invoice, please make reference to your invoice number. A receipt for payment will not be issued. Please mail your payment with the return portion of your invoice in the enclosed self-addressed envelope. Please note that rounding of your assessment to the nearest dollar has occurred. Your assessment for the PUC, including the OCA, the OSBA and the DPC where applicable, has been combined into one invoice; one payment for all applicable assessments is acceptable. **A TWENTY DOLLAR ($20.00) FEE WILL BE CHARGED FOR ALL DISHONORED OR BAD CHECKS REMITTED AS PAYMENT OF ASSESSMENTS.**

Your assessment has been computed by multiplying your gross intrastate operating revenues for the calendar year 2019 by the assessment factor for the public utility group of which you are a member. Your gross intrastate operating revenues for 2019 have been taken from the Assessment Reports Form GAO-19, AR-19-RR or AR-19-MC which you have filed with the Commission, or have been estimated by the Commission if you failed to file a timely report. Gross operating revenue reported to the Commission on the Assessment Reports may have been revised by the Commission to accurately reflect assessable revenue. The assessment factors for the various public utility groups are set forth in Schedule B enclosed herewith.

The approved estimate of expenditures of the Commission for the period July 1, 2020 to June 30, 2021 payable as a General Assessment by the public utilities which the Commission regulates has been determined as follows:

Approved budget for the Commission for the Fiscal Year July 1, 2020 through June 30, 2021:	$76,076,801
Deduct:	
Pipeline Operators per Act 127 of 2011	535,541
Various Fees Collected in FY 2019-20	688,473
UGWF Administration per Act 13 of 2012	453,404
Prior Year cost saving	8,292,175
UCR Collection for CY 2019	4,945,527
EGS/NGS fees per Act 155 of 2014	5,859,359
Total Deductions	$20,774,479
General Assessment Total Amount	$55,302,322

The way in which the total Public Utility Commission assessment of $55,302,322 has been allocated to the various groups of public utilities as shown on Schedules A and B enclosed herewith.

Rosemary Chiavetta
Secretary
PA Public Utility Commission

MAKE INQUIRIES TO:

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
P.O. Box 3265
Harrisburg, PA 17105-3265

FOR CERTIFIED AND EXPRESS CARRIERS

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
400 North Street
Harrisburg, PA 17120

CONTACT INFORMATION:

Assessment Section Information - Telephone 717-265-7548

Allocation of Expenses based on percent of prior year Public Utility Group workload
Budget Fiscal Year 2020-21

SCHEDULE A

Group	Total Expenditures per Utility Group Calendar Year 2019	Percentage Distribution	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group
Electric	$24,920,549	45.1523%	$24,970,270
Gas	$11,203,601	20.2993%	$11,225,984
Pipeline	$628,447	1.1387%	$629,728
Steam Heat	$318,410	0.5769%	$319,039
Tele./Tele.	$5,541,503	10.0404%	$5,552,574
Water/Sewer	$6,533,076	11.8370%	$6,546,136
Transportation - Passenger	$2,052,922	3.7196%	$2,057,025
Transportation - Property	$1,206,524	2.1860%	$1,208,909
Transportation - Rail	$2,787,117	5.0498%	$2,792,657
Total	**$55,192,149**	**100.00%**	**$55,302,322**

SCHEDULE B

Group	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group	Gross intrastate revenues by utility group Calendar Year 2019	General Assessment Factor by Utility Group (Col. (a) / by Col. (b))
	(a)	(b)	(c)
Electric	$24,970,270	$7,943,458,506	0.003143501031
Gas	$11,225,984	$4,082,124,332	0.002750034807
Pipeline	$629,728	$26,369,139	0.023881249972
Steam Heat	$319,039	$110,004,181	0.002900244310
Tele./Tele.	$5,552,574	$1,820,452,702	0.003050106160
Water/Sewer	$6,546,136	$1,447,058,777	0.004523752666
Transportation - Passenger	$2,057,025	$685,828,971	0.002999326490
Transportation - Property	$1,208,909	$508,973,483	0.002375190536
Transportation - Rail	$2,792,657	$78,530,272	0.035561534793
Total	**$55,302,322**	**$16,702,800,363**	**0.003310961084**

SUPPLEMENTAL SCHEDULE
FEDERAL SHORTFALL RELATED TO GAS SAFETY APPLICABLE TO GAS PUBLIC UTILITIES ONLY

	Estimated Commission Federal Shortfall for Calendar Year 2019 and 6 Months of Calendar Year 2020	Actual Commission Federal Shortfall for Calendar Year 2019 and 6 Months of Calendar Year 2020	Estimated Commission Federal Shortfall for Calendar Year 2020 and 6 Months of Calendar Year 2021
Gas	$0	$0	$0

	Net Estimated Commission Federal Shortfall for Fiscal Year 2020-21 Assessment	Reported Revenue for Gas Utility Group for Calendar Year 2019	Supplemental add-on Factor
Gas	$0	$4,082,124,332	0.000000000000

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

OFFICE OF SMALL BUSINESS ADVOCATE
DEPARTMENT OF COMMUNITY AND ECONOMIC DEVELOPMENT
NOTICE OF ASSESSMENT

EXPLANATION OF BILL FOR GENERAL ASSESSMENT
FOR FISCAL YEAR JULY 1, 2020 TO JUNE 30, 2021

The Pennsylvania Public Utility Commission is mandated under Act 181 of 1988, to levy upon the public utilities the Commission regulates a yearly assessment to fund the Pennsylvania Office of Small Business Advocate (herein called Small Business Advocate). The Governor and the Appropriation Committees of the Pennsylvania House and Senate approved an estimated operating budget of $1,896,000 for the Small Business Advocate for the Fiscal Year July 1, 2020 to June 30, 2021.

The enclosed assessment bill shows your proportionate share of the expenses of the Small Business Advocate for the Fiscal Year July 1, 2020 to June 30, 2021.

YOU ARE REQUIRED TO PAY THIS BILL WITHIN THIRTY DAYS AFTER YOU RECEIVE IT. Objections to the assessment must be made in writing within 15 days and shall set out in detail the grounds upon which you regard the assessment to be excessive, erroneous, unlawful, or invalid. Objections may be filed only by the person, partnership, or corporation assessed. **FAILURE TO PAY THE ASSESSMENT WHEN PAYMENT IS DUE WILL SUBJECT YOU TO PENALTIES.**

Be sure that your personal check or money order is written out in the same amount as your assessment invoice, and make your remittance payable to, "Commonwealth of PA". **DO NOT SEND CASH.** If you have reason to correspond with the Office of Small Business Advocate regarding your assessment invoice, please make reference to your invoice number. Please note that rounding of your assessment to the nearest dollar has occurred. Your assessment for the PUC, including the OCA, the OSBA and the DPC where applicable, has been combined into one invoice; one payment for all applicable assessments is acceptable. **A TWENTY DOLLAR ($20.00) FEE WILL BE CHARGED FOR ALL DISHONORED OR BAD CHECKS REMITTED AS PAYMENT OF ASSESSMENTS.**

Your Small Business Advocate assessment has been computed by multiplying your gross intrastate operating revenues for the calendar year 2019 by the assessment factor for the public utility group of which you are a member. Your gross intrastate operating revenues for 2019 have been taken from the report on Form GAO-19 which you have filed with the Commission, or have been estimated by the Commission, if you failed to file a timely report. Gross operating revenue reported to the Commission on the Assessment Reports may have been revised by the Commission to accurately reflect assessable revenue. The assessment factors for the various public utility groups are set forth in Schedule B enclosed herewith.

Estimate of the expenditures of the Office of Small Business Advocate for the Fiscal Year July 1, 2020 to June 30, 2021:	$1,896,000
Deduct:	
Credit from previous fiscal years:	225,000
Total Assessment	$1,671,000

The way in which the total Small Business Advocate assessment of $1,671,000 has been allocated to the various groups of public utilities is shown on Schedule A and B enclosed herewith.

Rosemary Chiavetta
Secretary
PA Public Utility Commission

MAKE INQUIRIES TO:

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
P. 0. Box 3265
Harrisburg, PA 17105-3265

FOR CERTIFIED AND EXPRESS CARRIERS

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
400 North Street
Harrisburg, PA 17120

CONTACT PERSON:

Assessment Section Information - Telephone 717-265-7548

OFFICE OF SMALL BUSINESS ADVOCATE

Allocation of Expenses based on percent of prior year Public Utility Group workload
Budget Fiscal Year 2019-20

SCHEDULE A

Group	Total Expenditures per Utility Group Calendar Year 2019	Percentage Distribution	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group
Electric	$580,439	35.0000%	$584,850
Gas	$597,023	36.0000%	$601,560
Steam Heat	$16,584	1.0000%	$16,710
Tele./Tele.	$199,008	12.0000%	$200,520
Water/Sewer	$265,344	16.0000%	$267,360
Total	**$1,658,398**	**100.00%**	**$1,671,000**

SCHEDULE B

Group	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group	Gross intrastate revenues by utility group Calendar Year 2019	General Assessment Factor by Utility Group (Col. (a) / by Col. (b))
	(a)	(b)	(c)
Electric	$584,850	$7,943,458,506	0.000073626620
Gas	$601,560	$4,082,124,332	0.000147364448
Steam Heat	$16,710	$110,004,181	0.000151903317
Tele./Tele.	$200,520	$1,820,452,702	0.000110148426
Water/Sewer	$267,360	$1,447,058,777	0.000184760982
Total	**$1,671,000**	**$15,403,098,498**	**0.000108484666**

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

OFFICE OF CONSUMER ADVOCATE
NOTICE OF ASSESSMENT

EXPLANATION OF BILL FOR GENERAL ASSESSMENT FOR PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE, OFFICE OF ATTORNEY GENERAL FOR FISCAL YEAR JULY 1, 2020 TO JUNE 30, 2021

The Pennsylvania Public Utility Commission is mandated under Act 15 of 1977, P.L. 19 as amended by Act 107 of 1978 and Act 25 of 1983, to levy upon the public utilities the Commission regulates a yearly assessment to fund the Pennsylvania Office of the Consumer Advocate (herein called Consumer Advocate), Office of the Attorney General. The Governor and the Appropriation Committees of the Pennsylvania House and Senate approved an estimated operating budget of $6,204,000 for the Consumer Advocate for the Fiscal Year July 1, 2020 to June 30, 2021.

The enclosed assessment bill shows your proportionate share of the expenses of the Consumer Advocate for the Fiscal Year July 1, 2020 to June 30, 2021.

YOU ARE REQUIRED TO PAY THIS BILL WITHIN THIRTY DAYS AFTER YOU RECEIVE IT. Objections to the assessment must be made in writing within 15 days and shall set out in detail the grounds upon which you regard the assessment to be excessive, erroneous, unlawful, or invalid. Objections may be filed only by the person, partnership, or corporation assessed. **FAILURE TO PAY THE ASSESSMENT WHEN PAYMENT IS DUE WILL SUBJECT YOU TO PENALTIES.**

Be sure that your personal check or money order is written out in the same amount as your assessment invoice, and make your remittance payable to, "Commonwealth of PA". **DO NOT SEND CASH.** If you have reason to correspond with the Office of Consumer Advocate regarding your assessment invoice, please make reference to your invoice number. Please note that rounding of your assessment to the nearest dollar has occurred. Your assessment for the PUC, including the OCA, the OSBA and the DPC where applicable, has been combined into one invoice; one payment for all applicable assessments is acceptable. **A TWENTY DOLLAR ($20.00) FEE WILL BE CHARGED FOR ALL DISHONORED OR BAD CHECKS REMITTED AS PAYMENT OF ASSESSMENTS.**

Your Consumer Advocate assessment has been computed by multiplying your gross intrastate operating revenues for the calendar year 2019 by the assessment factor for the public utility group of which you are a member. Your gross intrastate operating revenues for 2019 have been taken from the report on Form GAO-19 which you have filed with the Commission, or have been estimated by the Commission, if you failed to file a timely report. Gross operating revenue reported to the Commission on the Assessment Reports may have been revised by the Commission to accurately reflect assessable revenue. The assessment factors for the various public utility groups are set forth in Schedule B enclosed herewith.

Estimate of the expenditures of the Office of Consumer Advocate for the Fiscal Year July 1, 2020 to June 30, 2021:	$6,204,000
Deduct:	
Credit from previous fiscal year	0
Total OCA Assessment	$6,204,000

The way in which the total Consumer Advocate assessment of $6,204,000 has been allocated to the various groups of public utilities is shown on Schedule A and B enclosed herewith.

Rosemary Chiavetta
Secretary
PA Public Utility Commission

MAKE INQUIRIES TO:

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
P. 0. Box 3265
Harrisburg, PA 17105-3265

FOR CERTIFIED AND EXPRESS CARRIERS

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
400 North Street
Harrisburg, PA 17120

CONTACT PERSON:

Assessment Section Information - Telephone 717-265-7548

OFFICE OF CONSUMER ADVOCATE

Allocation of Expenses based on percent of prior year Public Utility Group workload
Budget Fiscal Year 2020-21

SCHEDULE A

Group	Total Expenditures per Utility Group Calendar Year 2019	Percentage Distribution	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group
Electric	$1,568,159	30.4774%	$1,890,818
Gas	$1,442,963	28.0442%	$1,739,862
Steam Heat	$0	0.0000%	$0
Tele./Tele.	$183,122	3.5590%	$220,800
Water/Sewer	$1,951,077	37.9194%	$2,352,520
Total	**$5,145,321**	**100.00%**	**$6,204,000**

SCHEDULE B

Group	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group	Gross intrastate revenues by utility group Calendar Year 2019	General Assessment Factor by Utility Group (Col. (a) / by Col. (b))
	(a)	(b)	(c)
Electric	$1,890,818	$7,943,458,506	0.000238034604
Gas	$1,739,862	$4,082,124,332	0.000426214848
Steam Heat	$0	$0	0.000000000000
Tele./Tele.	$220,800	$1,820,452,702	0.000121288512
Water/Sewer	$2,352,520	$1,447,058,777	0.001625725256
Total	**$6,204,000**	**$15,293,094,317**	**0.000405673297**

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

PENNSYLVANIA ONE CALL LAW
PUBLIC UTILITY COMMISSION DAMAGE PREVENTION COMMITTEE
NOTICE OF ASSESSMENT

EXPLANATION OF BILL FOR GENERAL ASSESSMENT
FOR FISCAL YEAR JULY 1, 2020 TO JUNE 30, 2021

The Pennsylvania Public Utility Commission is mandated under Act 50 of 2017, to levy upon the applicable public utilities the Commission regulates a yearly assessment to fund the Pennsylvania Public Utility Commission's Damage Prevention Committee (herein called Damage Prevention Committee or DPC). The Governor and the Appropriation Committees of the Pennsylvania House and Senate approved an estimated operating budget of $815,195 for the Damage Prevention Committee for the Fiscal Year July 1, 2020 to June 30, 2021.

The enclosed assessment bill shows your proportionate share of the expenses of the Damage Prevention Committee for the Fiscal Year July 1, 2020 to June 30, 2021.

YOU ARE REQUIRED TO PAY THIS BILL WITHIN THIRTY DAYS AFTER YOU RECEIVE IT. Objections to the assessment must be made in writing within 15 days and shall set out in detail the grounds upon which you regard the assessment to be excessive, erroneous, unlawful, or invalid. Objections may be filed only by the person, partnership, or corporation assessed. **FAILURE TO PAY THE ASSESSMENT WHEN PAYMENT IS DUE WILL SUBJECT YOU TO PENALTIES.**

Be sure that your personal check or money order is written out in the same amount as your assessment invoice, and make your remittance payable to, "Commonwealth of PA". **DO NOT SEND CASH.** Please note that rounding of your assessment to the nearest dollar has occurred. Your assessment for the PUC, including the OCA, the OSBA and the DPC where applicable, has been combined into one invoice; one payment for all applicable assessments is acceptable. **A TWENTY DOLLAR ($20.00) FEE WILL BE CHARGED FOR ALL DISHONORED OR BAD CHECKS REMITTED AS PAYMENT OF ASSESSMENTS.**

Your Damage Prevention Committee assessment has been computed by following the formula prescribed in the Act. We subtract from the estimated budget to operate the DPC in fiscal year 2020-21 the amount that was received in DPC fines in FY 2019-20 and Federal Grant funds that were received toward the operation of the program. Eighty percent of the remaining balance shall be included within the amount assessed to applicable public utilities under 66 PA.C.S. Section 510 and twenty percent of the remaining costs shall be assessed to the PA One Call System, with the fee to be paid to the Commission.

Estimate of the expenditures of the Damage Prevention Committee for the Fiscal Year July 1, 2020 to June 30, 2021:	$815,195
Deduct:	
Amount billed to Federal Grants (PHMSA):	$92,474
Amount of fines collected for FY 2019-20:	$514,282
Amount paid by PA One Call System:	$ 41,688
Total Assessment	$166,751

The way in which the total Damage Prevention Committee assessment of $166,751 has been allocated to the various groups of public utilities is shown on Schedule A and B enclosed herewith.

Rosemary Chiavetta
Secretary
PA Public Utility Commission

MAKE INQUIRIES TO:

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
P. 0. Box 3265
Harrisburg, PA 17105-3265

FOR CERTIFIED AND EXPRESS CARRIERS

Pennsylvania Public Utility Commission
Bureau of Administrative Services/Assess
400 North Street
Harrisburg, PA 17120

CONTACT PERSON:

Assessment Section Information - Telephone 717-265-7548

DAMAGE PREVENTION COMMITTEE

Allocation of Expenses based on percent of prior year DPC workload
Budget Fiscal Year 2020-21

SCHEDULE A

Group	Total Expenditures per Utility Group Calendar Year 2019	Percentage Distribution	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group
Electric	$165,946	19.1977%	$32,012
Gas	$370,589	42.8722%	$71,490
Pipeline	$19,808	2.2915%	$3,821
Tele./Tele.	$100,276	11.6006%	$19,344
Water/Sewer	$207,786	24.0380%	$40,084
Total	**$864,405**	**100.00%**	**$166,751**

SCHEDULE B

Group	Estimated Expenditures Fiscal Year 2020-2021 by Utility Group	Gross intrastate revenues by utility group Calendar Year 2019	General Assessment Factor by Utility Group (Col. (a) / by Col. (b))
	(a)	(b)	(c)
Electric	$32,012	$7,943,458,506	0.000004029983
Gas	$71,490	$4,082,124,332	0.000017512940
Pipeline	$3,821	$26,369,139	0.000144904238
Tele./Tele.	$19,344	$1,820,452,702	0.000010625928
Water/Sewer	$40,084	$1,447,058,777	0.000027700326
Total	**$166,751**	**$15,319,463,456**	**0.000010884911**

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).

Revised Response:

a, b, c and e. Please see GAS-RR-026 Attachment A – REVISED for the requested data**.** Also see the response to OCA-05-017.

d. The Company has no temporary employees.

Original Response:

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

d. The Company has no temporary employees.

Description	**Pre-HTY TME 11/30/2018**	**HTY TME 11/30/2019**	**Additional Headcount**	**FTY TME 11/30/2020**	**Additional Headcount**	**FPFTY TME 12/31/2021**
a.						
Employees						
Total Clerical Labor	84	90	0	90	0	90
Total Exempt Labor	144	167	15	182	0	182
Total Manual - Non-Union	16	14	2	16	0	16
Total Manual - Union	431	492	42	534	0	534
Total Employees	675	763	59	822	0	822

Description	**Pre-HTY TME 11/30/2018**	**HTY TME 11/30/2019 Per Books**	**Annualization Adjustment**	**HTY TME 11/30/2019 Normalized**	**Additional Headcount**	**Merit @ 3%**	**OT Reduction/ Cap/O&M Change**	**Annualization Adjustment**	**FTY TME 11/30/2020 Normalized**	**Additional Headcount**	**Merit @ 3%**	**Annualization Adjustment**	**FPFTY TME 12/31/2021 Normalized**
b.,c.,d., and e													
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)=(4)thru(8)**	**(9)**	**(10)**	**(11)**	**(12)=(9)thru(11)**
Payroll Expense													
Regular Payroll	27,978,237	31,713,297	3,012,122	34,725,419	1,139,386	624,145	(1,845,154)	589,913	35,233,710	0	647,901	537,643	36,419,254
Overtime Payroll	4,433,371	4,362,259	0	4,362,259	0	0	(1,300,000)	0	3,062,259	0	0	0	3,062,259
Premium Payroll	50,723	58,413	0	58,413	0	0	0	0	58,413	0	0	0	58,413
Net Affiliate Labor Transferred	(246,522)	(3,779)	0	(3,779)	0	0	0	0	(3,779)	0	0	0	(3,779)
Total Expense	32,215,808	36,130,190	3,012,122	39,142,312	1,139,386	624,145	(3,145,154)	589,913	38,350,603	0	647,901	537,643	39,536,147
Capital Payroll													
Regular Payroll	21,201,740	22,554,724	2,277,818	24,832,542	2,762,756	553,487	1,845,154	491,556	30,485,495	0	574,554	449,574	31,509,623
Overtime Payroll	3,345,133	3,277,396	0	3,277,396	0	0	(2,300,000)	0	977,396	0	0	0	977,396
Premium Payroll	38,272	43,886	0	43,886	0	0	0	0	43,886	0	0	0	43,886
Net Affiliate Labor Transferred	(186,010)	(2,840)	0	(2,840)	0	0	0	0	(2,840)	0	0	0	(2,840)
Total Capitalization	24,399,135	25,873,167	2,277,818	28,150,985	2,762,756	553,487	(454,846)	491,556	31,503,938	0	574,554	449,574	32,528,066
Total Payroll	**56,614,943**	**62,003,357**	**5,289,940**	**67,293,297**	**3,902,142**	**1,177,633**	**(3,600,000)**	**1,081,469**	**69,854,541**	**0**	**1,222,454**	**987,217**	**72,064,212**
Incentive Comp													
Expense	1,521,149	1,472,179	4,354	1,476,533	0	0	0	403,467	1,880,000	0	0	387,000	2,267,000
Capital	1,191,460	1,131,161	(21,831)	1,109,330	0	0	0	557,840	1,667,170	0	0	343,189	2,010,358
Total Incentive Comp	**2,712,609**	**2,603,340**	**(17,477)**	**2,585,863**	**0**	**0**	**0**	**961,307**	**3,547,170**	**0**	**0**	**730,189**	**4,277,358**