OCA Statement No. 1-Revised

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)
)
v.) **Docket No. R-2015-2468056**
)
Columbia Gas of Pennsylvania, Inc.)

REVISED DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

July 1, 2015

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EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

OCA Stmt. 1-Revised
R-2015-2468056
8-4-15
Harrisburg JS

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Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. My business address is 10480 Little Patuxent Parkway, Columbia, Maryland, 21044. I am a Public Utilities Consultant working with Exeter Associates, Inc. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I was previously a CPA licensed in the state of North Carolina, but have elected to place my license in an inactive status as I pursued other business interest.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examinations of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before that Commission. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

From June 1990 until July 1993, I was employed by Potomac Electric Power Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of the cost of service, rate base and ratemaking adjustments supporting the company's requests for revenue increases in the State of Maryland and the District of Columbia. I also conducted research on several issues affecting the electric utility industry for presentation to management.

From July 1993 through 2010, I was employed by Exeter Associates, Inc. as a Senior Regulatory Analyst. During that period I was involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination. This work involved natural gas, water, electric and telephone companies.

In 2010, I left Exeter Associates to pursue other business interests. In late 2014, I returned to Exeter to continue to work in a similar capacity to my work prior to my hiatus.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony and affidavits on numerous occasions before the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Virginia Corporation Commission, the Louisiana Public Service Commission, the Georgia Public Service Commission, the Maine Public Utilities Commission, the Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island, the Vermont Public Service Board, the Illinois

Commerce Commission, the West Virginia Public Service Commission, the Maryland Public Service Commission and the Federal Energy Regulatory Commission (FERC). My resume is attached hereto as Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am presenting testimony on behalf of the Office of Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter Associates has been retained by the OCA to assist in the evaluation of the General Rate Filing submitted by Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). I have been asked by the OCA to determine the level of revenues that Columbia should be authorized in this proceeding. In this testimony, I present my findings regarding Columbia's test year rate base and net operating income at present rates. Based on these amounts, I have determined the revenues that are required to generate the overall rate of return on rate base recommended by Mr. Aaron Rothschild on behalf of the OCA.

Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY AND EXHIBITS?

A. Yes. I have reviewed Columbia's testimony, exhibits and its rate filing. I have also reviewed the Company's responses to the OCA, the Bureau of Investigation & Enforcement (I&E), the Office of Small Business Advocate (OSBA) and other parties.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules LKM-1 through LKM-16. Schedule LKM-1 provides a summary of revenues and expenses under present and proposed rates. My adjustments to Columbia's claimed revenues and operating expenses are presented on Schedules LKM-2 through LKM-16.

Summary and Recommendations

Q. PLEASE SUMMARIZE THE RATE RELIEF REQUESTED BY COLUMBIA IN ITS FILING.

A. As indicated in the Company's filing, it is seeking a rate increase that would result in an increase in rate year revenues of $46.2 million. According to the Company the additional revenue sought would equate to an increase of 8.6 percent. Although the Company presented a Historical Test Year (HTY) ended November 30, 2014, and a Future Test Year (FTY) ending November 30, 2015, the requested revenue increase is derived from use of a Fully Forecasted Rate Year (FFRY) ending December 31, 2016.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. As shown on Schedule LKM-1, I have determined the Company has a revenue surplus of $ 8,811,828 for the FFRY ending December 31, 2016. This represents a decrease of $54,984,311 compared to Columbia's requested increase of $46,172,483. This is the amount by which revenues exceed those required to generate an overall rate of return of 6.72 percent after accounting for the OCA's adjustments to Columbia's claimed rate base and operating income. The return of 6.72 percent represents Mr. Rothschild's finding regarding the Company's overall rate of return.

Schedule LKM-2 summarizes my adjustments to Columbia's proposed rate year rate base. Schedule LKM-3 provides a summary of my adjustments to rate year revenues and expenses and the resulting operating income before income taxes at present rates. Schedule LKM-4 provides a proof of income taxes at present and proposed rates.

Q. WHAT TIME PERIODS HAVE YOU USED IN MAKING YOUR DETERMINATION OF COLUMBIA'S REVENUE REQUIREMENTS?

A. Consistent with Columbia's filing, I have used the FFRY ending December 31, 2016 as the basis for determining Columbia's rate year revenue requirements. This is the same time period used by the Company in its filing.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the remainder of my testimony, I document and explain each of the adjustments to rate base and operating income that I have made to arrive at the rate year revenue surplus shown on Schedule LKM-1. My discussion of these adjustments is organized into sections corresponding to the issue being addressed. These sections are set forth in the Table of Contents for this testimony.

Fully Forecasted Rate Year

Q. HAS COLUMBIA PROPERLY CALCULATED ITS REVENUE REQUIREMENTS IN THE FFRY?

A. No. The use of a fully projected future test year or rate year is intended to allow rates to be set to reflect the costs that will be incurred during the first year the rates will be in effect. Columbia has overstated its future rate year cost of service by reflecting costs at end of FFRY levels rather than at the levels of costs that will be experienced during the rate year. Rather than reflecting costs that will be incurred during the rate year ending December 31, 2016, Columbia has reflected costs that will be incurred as of January 1, 2017.

Q. CAN YOU PROVIDE EXAMPLES OF HOW COLUMBIA HAS OVERSTATED ITS RATE YEAR COST OF SERVICE?

A. Yes. One example is Columbia has included projected plant in service as of December 31, 2016 in rate base and has calculated depreciation expense based on the balance of plant in service as of December 31, 2016. If accepted, this proposal would result in Columbia earning a return beginning on the first day of the rate year on plant that will not be in service and, hence, will not be used and useful for up to one year later. Similarly, the Company would be allowed to recover a full year of depreciation expense on plant that will not be in service for the entire rate year.

Another instance is Columbia has adjusted wages to include the full annual effect of wage increases that are scheduled to be granted as of December 2016. As a result, Columbia's rate year revenue requirement is overstated by including wages that are not being paid for the first 11 months of the rate year.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING COLUMBIA'S DETERMINATION OF ITS RATE YEAR REVENUE REQUIREMENT?

A. Yes. In previous rate cases that predated Act 11, Columbia's revenue requirements were established based on FTY costs. Because the FTY ended at approximately the same time that rates were scheduled to take effect, adjustments were made to reflect plant in service, wage levels and other costs as of the end of the FTY. Columbia has followed a similar approach calculating its FFRY revenue requirements in this case. While reflecting costs at end of year levels may have been appropriate when revenue requirements were being established to reflect costs for a FTY that ended at the time that rates would go into effect, adjusting costs to year end levels is not appropriate now that a FFRY is being used to establish rates. Adjusting costs to end of rate year levels and beyond would result in Columbia recovering costs from ratepayers that are in excess of the costs that will be incurred during the rate year.

Q. WHAT IS THE PROPER APPROACH TO DETERMINING REVENUE REQUIREMENTS FOR THE RATE YEAR?

A. As noted previously, the use of a FFRY is intended to allow rates to be set to recover the costs that will be incurred during the first year the rates are in effect. Accordingly, rate base should reflect the average balances of plant in service, accumulated depreciation, accumulated deferred income taxes and other elements. Similarly, the amounts included for depreciation, wages and other expenses should be based on the costs that will be incurred during the rate year. Wages, for example, should reflect the wage rates in effect each month of the year, not the wage rates that will be in effect at the end of the year. Depreciation expense should reflect average levels of plant in service during the rate year.

Average Rate Base

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO MAKE TO COLUMBIA'S FILED CLAIM TO REFLECT AVERAGE RATE BASE DURING THE RATE YEAR?

A. In its filing, Columbia has reflected plant in service, accumulated depreciation, and accumulated deferred income taxes (ADIT) at the projected December 31, 2016 levels in determining its FFRY rate base claim. As explained previously, including the end of rate year plant in service and related balances in rate base would result in Columbia earning a return on a rate base that exceeds the Company's actual investment during the rate year. To reflect the Company's projected investment over the course of the first year the rates in this case will be in effect, I have adjusted plant in service, accumulated depreciation and ADIT included in rate base to reflect the average balances during the rate year.

Q. HOW HAVE YOU CALCULATED THE AVERAGE BALANCES OF PLANT, ACCUMULATED DEPRECIATION AND ADIT?

A. I have calculated the average balances of plant in service, accumulated depreciation and ADIT based on the 13-month average balance of each item for the period from December 31, 2015 through December 31, 2016. In developing these average balances, I have used actual and projected monthly balances for the time period. Columbia has provided actual monthly balances through April 2015 to which I combined with the projected balances for the remaining months of the period.

Q. HAVE YOU PREPARED A SCHEDULE THAT SHOWS THE EFFECT OF ADJUSTING COLUMBIA'S CLAIMED RATE BASE TO REFLECT THE 13-MONTH AVERAGE BALANCES OF PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT DURING THE FIRST YEAR THAT THE RATES APPROVED IN THIS PROCEEDING WILL BE IN EFFECT?

A. Yes. Schedule LKM-5 presents my adjustment to reflect the average rate year balances of plant, accumulated depreciation and ADIT. As shown there, the net effect of this adjustment is to reduce rate base by $119,468,288.

Operating Revenues – Customer Attrition

Q. WOULD YOU PLEASE EXPLAIN YOUR ADJUSTMENT TO OPERATING REVENUES RELATING TO CUSTOMER ATTRITION?

A. Yes. One of the components in Columbia's sales volumes forecast is customer attrition. The customer attrition component recognizes that despite the addition of new customers, there will be some customers that will leave the Company as well. Therefore, the customer attrition has a negative effect on customer growth and volume usage. The data used by Columbia to develop the attrition for residential and commercial customers is based upon a 4-year average for the years 2010 through 2013. However, the actual 4-year average that was calculated was used only for the derivation of the lost commercial customers. For residential customers, the Company used a higher rate that is not supported by the 4-year average. As calculated by the Company, the 4-year average rate for residential customers resulted in a rate of -0.3 percent. However, the rate Columbia used to develop the lost residential customers was -0.4 percent. In an attempt to gain an understanding for the change from the -0.3 percent to -0.4 percent, I asked Columbia to provide support for the higher rate. Essentially, the Company stated that they simply increased the calculated average from -0.3 percent to -0.4 percent.

I am recommending an adjustment to operating revenues because I disagree with the 2010 through 2013 period used by the Company and I disagree with the use of a 4-year average in deriving the attrition rate.

Q. WHY DO YOU DISAGREE WITH THE 2010 THROUGH 2013 TIME PERIOD USED BY THE COMPANY?

A. I disagree with the 2010 through 2013 time period because the data for 2014 is available. More recent data is preferable because they are more representative of current operations. In addition, I believe the average of the most recent 3 years, 2012 through 2014, is more representative of current activity for both residential and commercial customers. Therefore, I have made an adjustment to operating revenues to reflect the customer attrition based upon the use of the most recent three-year average. As presented on Schedule LKM-6 my adjustment to operating revenue results in an increase in operating revenues of $575,053.

Operating Revenues – Weather Normalization

Q. WOULD YOU PLEASE EXPLAIN YOUR ADJUSTMENT TO OPERATING REVENUES RELATING TO WEATHER NORMALIZATION?

A. Yes. Another component of Columbia operating revenue annualization is the weather normalization component, which takes the heats sensitive usage into consideration. The heat sensitive usage of the Company's annual Dth volumes sold is driven by weather conditions, so those volumes can vary from year to year. The weather normalization adjustment is the process whereby the sales volumes are adjusted to normalize the effect of the test year weather conditions on the annualized sales volumes. This process involves isolating the customer usage data and expressing it in heating degree days (HDD). The difference between the actual HDD during the test year and the normalized HDD forms the basis of the weather normalization adjustment. The normal HDD is calculated from 20-year weather data.

According to the Company, the weather normalization component of the annual revenue has been calculated in a manner consistent with prior rate cases, with the exception of updating the data as more recent data become available. The data used by Columbia for FFRY is based upon the 20 years ended 2013.

I am recommending an adjustment to operating revenues to update the weather normalization component to reflect HDD data through 2014. In the response to OSBA-1-001, Columbia provided the updated volumes reflecting the 20-year HDD through 2014. I have incorporated that information into the FFRY revenues to derive the adjustment increasing operating revenue by $707,914 as presented on Schedule LKM-7.

Labor Expense

Q. HOW HAS COLUMBIA DERIVED ITS RATE YEAR CLAIM FOR SALARIES AND WAGES FOR COMPANY EMPLOYEES?

A. Columbia developed its rate year labor claim beginning with the HTY per books labor expense adjusted for a 3 percent merit increase to occur during the FTY and the addition 36 new employees. The Company also added the cost of a training initiative that is anticipated to occur during the FTY. For the FFRY, the Company adjusted labor expense to include a 3 percent merit increase, the inclusion 17 additional employees and the annualization of FFRY salary and wage increases.

Based upon the data provided by the company, I am recommending an adjustment that revises the calculation of the incremental cost of new employees; removes the FFRY payroll annualization expense; and removes the training initiatives costs.

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE DETERMINATION COST OF NEW EMPLOYEES?

A. I am proposing to make several changes to the Company's new employee costs. Columbia's adjustment for new employee salaries and wages is based upon an average incremental cost per employee of $50,000. This amount was applied to the number of new employees for the FTY and the FFRY to derive the annual costs.

With regard to the incremental cost of new employees, the Company calculated it costs utilizing a salary rate per employee of $62,522 based upon an average starting salary rate of $51,500 plus an average overtime per employee of

$11,000. To that amount the Company applied a 20 percent capitalization rate to derive its net incremental cost per employee of $50,000. In my adjustment, I have revised the net incremental cost per employee to reflect the several changes. First, the Company indicated the actual starting salary per employee was actually $62,300, but it chose to use $51,500 to be conservative. In my revision of the incremental costs, I have used the actual rate of $62,300.

The second change I made was the average overtime per employee. Columbia based its overtime per employee solely on the HTY. Since overtime hours can vary from year-to-year, I believe it is more reasonable to use a multi-year average. Given that the 12 months ended November 30, 2013 was readily available, I used an average of the 12 months ended November 30, 2013 and the HTY to derive an average overtime per employee of $10,350.

The third change I made to the determination of the average incremental cost for new employees involved the capitalization rate. Columbia stated that the actual capitalization rate was more likely to be 40 percent, but instead it used a 20 percent capitalization rate. In my revision of the incremental costs per new employee, I used the 40 percent rate.

The foregoing changes that I have just discussed, results in an average incremental salary per employee of $43,590.

The next component of the incremental cost of new employees is the number of employees. Columbia acknowledges that employees will be added over time instead of all employees being hired on one date in the response to the response to OCA-4-039. Based upon the amounts included in both the FTY and the FFRY budgets for new employees I have reflected an increase of 25 employees during the FTY and 25 employees during the FFRY.

Q. WHAT IS THE NEXT CHANGE YOU MADE TO LABOR COSTS?

A. The next change I have made is to remove the training costs of $519,000. I have moved these costs because, based upon my understanding of the manner in which the Company budgets, labor costs are a separate budget element. Therefore, the labor expense budget includes all labor costs. As an example, in the response to I&E-RE-26, Attachment A, there are line items for "Safety Training", "Technical Train Weld", "Safety Meeting", "Repairing Meter Installation", etc. I specifically inquired about labor costs being included in those costs, and the Company confirmed there are no labor costs in those budgeted amounts. Additionally, since the training was a planned activity for the FTY, they should not be included in the FFRY costs.

Q. WHAT IS THE FINAL CHANGE YOU MADE TO LABOR EXPENSE?

A. The final change I have made to labor expense is to remove the FFRY labor expense annualization adjustment. The adjustment as presented by the Company is intended to reflect labor rate increase granted during the FFRY as if they were in effect all year. As I have explained earlier, such an annualization adjustment would restate costs to the end of year level and present as if they were incurred during the entire rate year. As I have explained this would violate the fully forecasted rate year concept.

Q. PLEASE SUMMARIZE YOU LABOR EXPENSE ADJUSTMENT.

A. On Schedule LKM-8, I have made an adjustment to reduce labor expense by $1,138,592. This adjustment revises Columbia's claim for the incremental cost of new employees; removes the FFRY payroll annualization expense; and removes the training initiatives costs.

NCSC Shared Services

Q. WHAT ADJUSTMENT HAVE YOU MADE TO NCSC SHARED SERVICES?

A. In the Company's filing, $1,155,000 of additional labor costs were included in the Company's share of NCSC Shared Services costs. Out of that total amount, $462,961 was allocated for 36 new employees to be hired during the FTY. Additionally, Columbia made an adjustment to annualize its share of NCSC Shared Services' FFRY labor cost increases.

I have made two adjustments to Columbia's claim. First, I have removed the annualization of the FFRY labor cost increases. As I have explained earlier, such an annualization adjustment would restate costs to the end of year level, as if they were incurred during the entire rate year. This violates the fully forecasted rate year concept.

The next adjustment I made is to reflect the number of new employees as of April 2015. As indicated by the Company, all new employees were to be hired during the FTY. My adjustment was to reflect the most recent actual number employees hired to date.

On Schedule LKM-9, I present this adjustment which reduces O&M expenses by $210,857.

NCSC Shared Services NGD Operations

Q. WHAT ADJUSTMENT HAVE YOU MADE TO NCSC SHARED SERVICES NGD OPERATIONS?

A. I have removed the annualization of the FFRY labor cost increases. As I have explained earlier, such an annualization adjustment would restate costs to the end of year level and present as if they were incurred during the entire rate year. This would violate the fully forecasted rate year concept. I have presented this adjustment on Schedule LKM-10, which reduces O&M expenses by $111,874.

Profit Sharing and Stock Awards

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THE COMPANY'S CLAIMED COSTS FOR ITS PROFIT SHARING PLAN?

A. As part of Columbia's overall employee compensation, Columbia and the Service Company (NCSC) have three incentive compensation plans. Two of the plans, the Profit Sharing and the Stock Awards plans, are of concern because of how payments under those plans are based. The profit sharing plan consists of contributions to a retirement plan for all eligible employees. Profit sharing payments are based solely on the achievement of earnings per share goals. Similarly, stock awards are designed to link the compensation of the participants to the interests of stockholders. The adjustment I am recommending is to remove the costs associated with both of these plans because the costs of these plans are based exclusively on achieving business unit and corporate financial goals and, as a result, are not properly recoverable from ratepayers for several reasons. First, if the financial targets are set properly, achieving the necessary performance should be self-supporting. In other words, measures that achieve additional cost savings, increase revenue or otherwise improve financial result should generate the necessary income to make the profit sharing payments. Second, profit sharing payments are not dependent on meeting quality of service, efficiency or salary goals. Finally, the incentive to improve financial performance is not necessarily consistent with the interests of Columbia's ratepayers.

Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENT TO ELIMINATE PROFIT SHARING PAYMENTS?

A. As shown on Schedule LKM-11, this adjustment, in aggregate, reduces FFRY O&M expenses by $1,840,279.

Benefits Expense

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE FFRY CLAIM FOR EMPLOYEE BENEFITS EXPENSE?

A. Columbia developed its Employee Benefits for the FFRY based upon its projected Employee headcount at the end of the FFRY of 633. The adjustment I am recommending is to recognize that the expenses to be included in rates under FFRY concept should be the costs incurred during the year rather than the end of year costs. Therefore, my adjustment to employee benefit costs is based upon including the average level of costs for the new employees to be added during the FFRY. As I explained earlier, such an annualization adjustment would restate costs to the end of year level and present as if they were incurred during the entire rate year, which is inconsistent with the fully forecasted rate year concept. This adjustment is presented on Schedule LKM-12 and it reduces O&M expenses by $107,197.

Injuries and Damages Expense

Q. WHAT ADJUSTMENT HAVE YOU MADE TO INJURIES AND DAMAGES EXPENSE?

A. Columbia has adjusted Injuries and Damages expense to normalize the level of expense to an annual level of $429,150. This amount is derived through a series of calculations to adjust the HTY expense level to the FFRY. First, the Company determined the HTY costs by using a price deflator to express the costs incurred during the 4 years prior to 2014 in 2014 dollars. The costs for those 5 years were averaged to derive the normalized level of expense for the HTY. To determine the FTY expense, an inflation factor was applied to the HTY expense. A similar calculation was made to derive the FFRY expense by applying an inflation factor to the FTY amount.

I disagree with the level injuries and damages presented by the Company because the various series of price escalations applied in determining the FFRY amount escalates the costs to a level not representative of the level of expense recorded by the Company. Therefore, I am recommending an adjustment that reduces the Company's claim to a normalized level that is reasonable given the recent level of costs incurred by the Company.

Q. *HOW HAVE YOU CALCULATED YOUR ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE?*

A. I have calculated the Injuries and Damages expense following a process similar in manner to the way the Company calculates injuries and damages for budgeting purposes. In the response to OCA-4-031, Columbia explains that in its calculation, the company selects the actual per books expense accruals for the most recent 5 historical years and discards the highest and lowest amounts. The remaining three years are averaged to derive the amount that is accrued. Following this process, I discarded the amount for the 12 months ended November 2010 ($726,103) and the amount for 12 months ended November 2014 ($261,045) leaving the amounts for the 12 months ended November 2013, 2012 and 2011 of $362,842, $325,681, and $309,942, respectively. The average of these three amounts resulted in a normalized level of injuries and damages of $332,822 and an adjustment of $96,328. This adjustment is presented on Schedule LKM-13.

Q. DID YOU REVIEW ANY ADDITIONAL DATA TO DETERMINE THE REASONABLENESS OF YOUR ADJUSTMENT?

A. Yes. I reviewed the data for the 3 year period ended November 2012, 2013 and 2014. I observed that the amounts paid in claims during those years were $325,681, $362,842 and $261,044 for 2012, 2013 and 2014, respectively. I also reviewed the expense amount recorded for each of those years. I observed that the expense amounts during those years were $255,837, $339,052 and $240,979 for 2012, 2013 and 2014, respectively. The 12 months ended November 2010 was the one year where the amount I calculated differed significantly from the amount presented by the Company. The Company explained that for that year, there was a higher than normal workers compensation claim paid during that period. However, the data provided by the Company show that since that year no other workers compensation claim paid has been close to that amount. The inclusion of the $726,103 in the average for normalizing the injuries and damages claim would skew the average upward. Based upon these facts, I do believe the amount I have included for injuries and damages is reasonable.

Rents and Leases

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO RENTS AND LEASES.

A. The level of Rents and Leases expenses claimed by Columbia is based upon the costs related to its existing and new leases that will be in effect during the FFRY and an annualization to reflect the full annual cost of new leases that will begin during the FFRY. I am recommending two adjustments to Rents and Leases expense.

The first adjustment involves the Strabane Construction Office/Warehouse facility. Each facility included in the cost of service has a specific use and purpose. Accordingly, the Strabane facility is described by the Company to be a new lease initially planned as an office and warehouse space. However, the Company has indicated that the space requirements have been changed and reduced to an office only space. The Company indicates that a site has not been selected as potential locations are still being toured. The cost included in the FFRY of $150,000 is based upon the original space requirements for warehouse and office. Columbia indicates that one of its existing warehouse facilities will now be used for the warehousing activities that were planned for the Strabane location, so the warehouse is not needed.

Given that the space requirements have been changed and a location has not yet been selected, I believe inclusion of the costs related to the Strabane location is inappropriate.

The second adjustment involves the York Facility and the training center facility. Both of those leases will begin during April 2016. Therefore, the budget includes 9 months of lease payments. The Company has proposed an adjustment to annualize the lease payment to reflect a full year by including three additional months. As I explained earlier, such an annualization adjustment would restate costs to the end of year level and present as if they were incurred during the entire rate year. As I have explained this would violate the fully forecasted rate year concept. Therefore, I have removed these costs.

To summarize, on Schedule LKM-14, I have made an adjustment to reduce O&M expenses by $364,395.

Depreciation & Amortization Expense

Q. HOW HAS COLUMBIA DETERMINED ITS CLAIMED RATE YEAR DEPRECIATION EXPENSE?

A. Columbia has based its rate year depreciation expense on the projected balance of plant in service as of the end of the FFRY, December 31, 2016.

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM BASED ON THE DECEMBER 31, 2016 END OF RATE YEAR PLANT IN SERVICE?

A. No. By basing depreciation on the balance of plant in service as of the end of the rate year, Columbia has reflected a level of depreciation expense that will not begin to be incurred until after January 1, 2017 instead of the depreciation expense that will be incurred during the rate year ending December 31, 2016. Prior to this case, when Columbia used a future test year that ended before rates went into effect, the use of end of FTY plant to calculate depreciation expense was appropriate in order to reflect the depreciation expense at the time rates went into effect. However, in this case, where Columbia is now allowed to utilize a fully projected future test year or rate year, the use of end of rate year plant to calculate depreciation expense is no longer appropriate because doing so significantly overstates the depreciation expense that will be incurred during the rate year. This in turn would allow Columbia to earn in excess of its allowed rate of return.

Q. HOW ARE YOU PROPOSING TO DETERMINE DEPRECIATION EXPENSE?

A. In order to reflect the level of depreciation expense that will be incurred during the rate year, I have calculated depreciation expense based on the 13-month average balance of plant in service. I have based this calculation on the composite depreciation rate based on the depreciation rates for the three major categories of plant accounts proposed by Columbia in this case. As shown on Schedule LKM-15, my adjustment to reflect the depreciation expense that will be incurred during the rate year ending December 31, 2016 reduces depreciation expense by $3,913,460.

FICA Taxes

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PAYROLL TAXES?

A. I have adjusted FICA taxes to reflect the adjustments that I have made to labor expense charged to O&M for existing and new Columbia employees. As shown on Schedule LKM-18, recognizing these changes in payroll subject to payroll taxes reduces FICA taxes by $87,102.

Interest Synchronization

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax deductible interest for ratemaking, I have multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure recommended by OCA witness Rothschild. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown at the bottom of Schedule LKM-4, this adjustment reduces the interest deduction by $1,082,639 compared to the interest deduction recognized by Columbia. This increases state and federal income taxes by $180,668 and $569,739, respectively.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Lafayette K. Morgan, Jr., hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 1-Revised, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: Lafayette Morgan Jr.
Lafayette K. Morgan, Jr.

Consultant Address: Exeter Associates, Inc.
Suite 300
10480 Little Patuxent Parkway
Columbia, MD 21044

DATED: 7/1/15

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2015-2468056**
	)	
Columbia Gas of Pennsylvania, Inc.	)	

SCHEDULES ACCOMPANYING THE
REVISED DIRECT TESTIMONY
OF
LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

July 1, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Operating Income
For the Rate Year Ending December 31, 2016

Line No.		Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
	Operating Revenues					
1	Base Revenues (Incl. Transportation)	$ 310,753,903	$ 1,279,967	$ 312,033,870	$ (8,790,091)	$ 303,243,779
2	Fuel Revenues	190,479,760	-	190,479,760	-	190,479,760
3	Rider USP	27,644,938	-	27,644,938	-	27,644,938
4	Gas Procurement Charge	2,322,967	-	2,322,967	-	2,322,967
5	Merchant Function Charge	1,752,694	-	1,752,694	-	1,752,694
6	Rider CC	41,900	-	41,900	-	41,900
7	Rider CAC	-	-	-	-	-
8	Total Sales and Transportation Revenues	$ 532,996,162	$ 1,279,967	$ 534,276,129	$ (8,790,091)	$ 525,486,038
9	Off System Sales Revenue	-	-	-	-	-
10	Late Payment Fees	1,318,074	-	1,318,074	(21,737)	1,296,337
11	Other Operating Revenues (Excl. Transport.)	584,914	-	584,914	-	584,914
12	Total Operating Revenues	$ 534,899,150	$ 1,279,967	$ 536,179,117	$ (8,811,828)	$ 527,367,289
13						
14	Operating Revenue Deductions					
15	Gas Supply Expense	$ 190,479,760	$ -	$ 190,479,760	$ -	$ 190,479,760
16	Off System Sales Expense	-	-	-	-	-
17	Gas Used in Company Operations	-	-	-	-	-
18	Operating and Maintenance Expense	177,299,816	(3,869,522)	173,430,294	(115,079)	173,315,215
19	Depreciation and Amortization Exp.	50,115,986	(3,913,460)	46,202,526	-	46,202,526
20	Net Salvage Amortized	4,635,342	-	4,635,342	-	4,635,342
21	Taxes Other Than Income	3,221,085	(87,102)	3,133,983	-	3,133,983
22	Total Operating Revenue Deductions	425,751,989	(7,870,085)	417,881,904	(115,079)	417,766,825
23						
24	Operating Income Before Income Taxes	109,147,161	9,150,052	118,297,213	(8,696,749)	109,600,464
25						
26	Income Taxes	29,190,575	4,245,901	33,436,476	(4,496,302)	28,940,174
27	Investment Tax Credit	(360,240)	-	(360,240)	-	(360,240)
28						
29	Net Operating Income	$ 80,316,826	$ 4,904,150	$ 85,220,976	$ (4,200,447)	$ 81,020,529
30						
31	Rate Base	$ 1,325,130,928		$ 1,205,662,640		$ 1,205,662,640
32						
33	Return On Rate Base	6.06%		7.07%		6.72%

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COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Revenue Increase at OCA Rate of Return
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	Adjusted Rate Base	$ 1,205,662,640	Schedule LKM-2, Page 2
2	Required Rate of Return	6.720%	
3			
4	Net Operating Income Required	$ 81,020,529	
5	Net Operating Income at Present Rates	*85,220,976*	Schedule LKM-1, Page 1
6			
7	Income Deficiency/(Surplus)	$ (4,200,447)	
8	Revenue Multiplier	2.09783092	
9			
10	Required Change in Company Revenue	$ (8,811,828)	
11			
12	Proposed Revenue Change	$ (8,811,828)	
13	Less: Uncollectibles	(115,079)	
14	Plus: Late Payment		
15	Income Before State Taxes	$ (8,696,749)	
16	*State Income Tax Effect Tax Rate*		
17	Less: State Income Tax	(2,234,523)	
18	Income Before Federal Taxes	$ (6,462,226)	
19	Federal Income Tax @35%	(2,261,779)	
20			
21	Net Income Surplus/(Deficiency)	$ (4,200,447)	

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Rate Base
For the Rate Year Ending December 31, 2016

	Amount per Company Filing	OCA Rate Base Adjustments	Amount After OCA Adjustments
Property Plant and Equipment			
Gas Plant in Service	$ 1,945,029,486	$ (120,937,277)	$ 1,824,092,209
Construction Work in Progress	-	-	-
Gas Stored Underground - Non Current	3,794,693	-	3,794,693
Depreciation Reserve	(386,737,768)	7,718,671	(379,019,097)
Accumulated Provision Gas Lost - Underground Storage	(163,467)	-	(163,467)
Net Plant in Service	$ 1,561,922,944	$ (113,218,606)	$ 1,448,704,338
Working Capital			
Materials & Supplies	$ 648,987	$ -	$ 648,987
Prepayments	2,107,010	-	2,107,010
Gas Stored Underground	58,489,294	-	58,489,294
Cash Allowance	-	-	-
Total Working Capital	$ 61,245,291	$ -	$ 61,245,291
Deferred Income Taxes			
Income Taxes	$ 8,949,377	$ -	$ 8,949,377
Depreciation	(303,643,348)	(6,249,681)	(309,893,029)
Other	-	-	-
Total Deferred Income Taxes	$ (294,693,971)	$ (6,249,681)	$ (300,943,652)
Customer Deposits	(3,131,607)	-	(3,131,607)
Customer Advances for Construction	(211,729)	-	(211,729)
Total Rate Base	$ 1,325,130,928	$ (119,468,288)	$ 1,205,662,640

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Rate Base Adjustments
For the Rate Year Ending December 31, 2016

	Source	Amount
Rate Base per Company Filing	Schedule LKM-2, Page 1	$ 1,325,130,928
OCA Adjustments:		
Plant In Service	Schedule LKM-6	$ (120,937,277)
Accumulated Depreciation	Schedule LKM-6	7,718,671
Accumulated Deferred Income Taxes	Schedule LKM-6	(6,249,681)
Total Ratemaking Adjustments		$ (119,468,288)
Adjusted Rate Base per OCA		$ 1,205,662,640

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COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending December 31, 2016

Line No.		Amount	Source
1	Operating Income Before Income Taxes per Company	$ 109,147,161	Exhibit No. 102, Schedule 3, Page 3
2			
3	OCA Adjustments:		
4	Sales Attrition	$ 572,053	Schedule LKM-6
5	Weather Normalization	707,914	Schedule LKM-7
6	CPA Payroll	1,138,592	Schedule LKM-8
7	NCSC Shared Services	210,857	Schedule LKM-9
8	NCSC NGD	111,874	Schedule LKM-10
9	Profit Sharing	1,840,279	Schedule LKM-11
10	Employee Benefits	107,197	Schedule LKM-12
11	Injuries and Damages	96,328	Schedule LKM-13
12	Annual Rents and Leases	364,395	Schedule LKM-14
13	Depreciation & Amortization	3,913,460	Schedule LKM-15
14	FICA Taxes	87,102	Schedule LKM-16
15	Total OCA Adjustments	$ 9,150,052	
16			
17	Operating Income Before Income Taxes per OCA	$ 118,297,213	

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COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending December 31, 2016

Line No.		Operating Revenues	O&M Expenses	Depreciation & Amortization	Taxes Other Than Income	Operating Income Before Income Taxes
1	Amount per Company	$ 534,899,150	$367,779,576	$ 54,751,328	$ 3,221,085	$ 109,147,161
2						
3	OCA Adjustments:					
4	Sales Attrition	$ 572,053	$ -	$ -	$ -	$ 572,053
5	Weather Normalization	707,914	-	-	-	707,914
6	CPA Payroll		(1,138,592)	-	-	1,138,592
7	NCSC Shared Services	-	(210,857)	-	-	210,857
8	NCSC NGD	-	(111,874)	-	-	111,874
9	Profit Sharing	-	(1,840,279)	-	-	1,840,279
10	Employee Benefits	-	(107,197)	-	-	107,197
11	Injuries and Damages	-	(96,328)	-	-	96,328
12	Annual Rents and Leases	-	(364,395)	-	-	364,395
13	Depreciation & Amortization	-	-	(3,913,460)	-	3,913,460
14	FICA Taxes	-	-	-	(87,102)	87,102
15						
16	Total OCA Adjustments	$ 1,279,967	$ (3,869,522)	$ (3,913,460)	$ (87,102)	$ 9,150,052
17						
18	Total Adjusted Income Before Income Taxes	$ 536,179,117	$363,910,054	$ 50,837,868	$ 3,133,983	$ 118,297,213

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COLUMBIA GAS OF PENNSYLVANIA INC.

Reconciliation of State and Federal Income Taxes
For the Rate Year Ending December 31, 2016

Line No.		Amount Per Company at present rates	OCA Adjustments	OCA Adjusted Amounts at Present Rates	Pro Forma Change in Revenues	Amounts After Change in Revenues
1	Net Operating Income Before Income Taxes	$ 109,147,161	$ 9,150,052	$ 118,297,213	$ (8,696,749)	$ 109,600,464
2						
3	*Interest Expense*	*(32,068,168)*	*1,082,639*	*(30,985,530)*	-	*(30,985,530)*
4	Other Flow Through Adjustments	6,413,181	-	6,413,181	-	6,413,181
5	Deferral Adjustments	(58,946,444)	-	(58,946,444)	-	(58,946,444)
6						
7	Total Statutory Adjustments	$ (84,601,431)	$ 1,082,639	$ (83,518,792)	$ -	$ (83,518,792)
8	Pennsylvania Bonus Depreciation	(7,572,748)	-	(7,572,748)	-	(7,572,748)
9						
10	*CNIT Taxable Income*	$ 16,972,982	$ 10,232,690	$ 27,205,672	$ (8,696,749)	$ 18,508,923
11	Net Operating Loss Adjustment	5,091,895	-	5,091,895	13,670,847	18,762,742
12	Pennsylvania Taxable Income	$ 11,881,087	$ 10,232,690	$ 22,113,777	$ (22,367,596)	$ (253,819)
13						
14	Pennsylvania Income Tax Payable @ 9.99%	1,186,921	1,022,246	2,209,166	(2,234,523)	-
15	Deferred Tax on Inventory Adjustment	1,717	-	1,717	-	1,717
16	Deferred Tax on Customer Advances	(52,820)	-	(52,820)	-	(52,820)
17	Total Pennsylvania Income Taxes	$ 1,135,818	$ 1,022,246	$ 2,158,063	$ (2,234,523)	$ -
18						
19	Net Operating Income Before Income Taxes	$ 109,147,161	$ 9,150,052	$ 118,297,213	$ (8,696,749)	$ 109,600,464
20	Pennsylvania Income Tax Payable @ 9.99%	1,186,921	1,022,246	2,209,166	(2,234,523)	-
21	Total Statutory Adjustments	(84,601,431)	1,082,639	(83,518,792)	-	(83,518,792)
22	Taxable Income	$ 23,358,809	$ 9,210,445	$ 32,569,254	$ (6,462,226)	$ 26,081,671
23						
24	Federal Income Tax Payable @ 35%	8,175,583	3,223,656	11,399,239	(2,261,779)	9,128,585
25	Federal Deferred Tax @ 35%	20,631,255	-	20,631,255	-	20,631,255
26	Tax Refund Amortization	(681,571)	-	(681,571)	-	(681,571)
27	Flow Back of Excess Deferred Taxes	(88,396)	-	(88,396)	-	(88,396)
28	Effect of CNIT Deferred Tax on FIT	17,886	-	17,886	-	17,886
29	Net Federal Income Tax	$ 28,054,758	$ 3,223,656	$ 31,278,413	$ (2,261,779)	$ 29,007,759

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Rate Base to Reflect 13-Month Average Balance for Plant and Related Items
For the Rate Year Ending December 31, 2016

Line No.		Balance Per Company at December 31, 2016		13-Month Average Balance per OCA		OCA Adjustment
			1/			
1	Plant In Service	$ 1,945,029,486		$ 1,824,092,209	2/	$ (120,937,277)
2						
3	Accumulated Depreciation	(386,737,768)		(379,019,097)	3/	7,718,671
4						
5	Net Plant	$ 1,558,291,718		$ 1,445,073,112		$ (113,218,606)
6						
7	Accumulated Deferred Income Taxes	(294,693,971)		(300,943,652)	4/	(6,249,681)
8						
9	Net Balance	$ 1,263,597,747		$ 1,144,129,459		$ (119,468,288)
10						
11						
12						
13						
14	Notes:					
15	1/ Exhibit 108, Page 3					
16	2/ Company Response to OCA-7-003.					
17	4/ Company Response to OCA-7-005					
18	4/ Company Response to OCA-7-007					
19						

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Schedule LKM-6

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Operating Revenues to Reflect 3-Year Average Customer Attrition
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	Residential Sales Service Revenues Based Upon 3-Year Average Attrition	$ 304,206,884	1/
2	Residential Sales Service Revenues Per Company	303,828,729	2/
3			
4	Adjustment to Residential Sales Service Revenues	$ 378,155	
5			
6	Small General Service Revenues Based Upon 3-Year Average Attrition	$ 86,628,242	1/
7	Small General Service Revenues Per Company	86,434,344	2/
8			
9	Adjustment to Small General Service Revenues	$ 193,898	
10			
11			
12	Total Adjustment to Operating Revenues	$ 572,053	

Notes:
1/ Calculated based upon data provided in Response to OCA-9-002.
2/ Company Exhibit No. 103, Page 8 of 15.

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Operating Revenues to Reflect Updated Weather Normalization through 2014
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	Residential Sales Service Revenues Based Upon Updated Weather Normalization	$ 304,768,493	1/
2	Residential Sales Service Revenues Per Company	303,828,729	2/
3			
4	Adjustment to Residential Sales Service Revenues	$ 939,764	
5			
6	Small General Service Revenues Based Upon Updated Weather Normalization	$ 86,202,494	1/
7	Small General Service Revenues Per Company	86,434,344	2/
8			
9	Adjustment to Small General Service Revenues	$ (231,850)	
10			
11			
12	Total Adjustment to Operating Revenues	$ 707,914	

Notes:
1/ Calculated based upon data provided in Response to OSBA-1-001.
2/ Company Exhibit No. 103, Page 8 of 15.

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Schedule LKM-8

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Annualize Payroll Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount Per Company 1/	Amount Per OCA	Adjustment
1	HTY Labor Expense	$ 25,550,026	$ 25,550,026	$ -
2				
3	Merit increase at 3 Percent	766,501	766,501	-
4				
5	Additional Headcount	1,240,112	1,081,125	(158,987)
6				
7	Training Initiatives	519,361	-	(519,361)
8				
9	FTY Labor Expense	$ 28,076,000	$ 27,397,652	$ (678,348)
10				
11	Merit increase at 3 Percent	842,280	821,930	(20,350)
12				
13	Additional Headcount	1,223,720	1,081,125	(142,595)
14				
15	FFRY Labor Expense Before Ratemaking Adjustment	$ 30,142,000	$ 29,300,707	$ (841,293)
16				
17	FFRY Labor Animalization	297,299 2/	-	(297,299)
18				
19	FFRY Labor Expense	$ 30,439,299	$ 29,300,707	$ (1,138,592)
20				
21				
22				

Notes:

1/ Exhibit No. 104, Schedule No. 10.

2/ Exhibit No. 104, Schedule No. 1, Page 4.

3/ Calculation of Average Annual salary

Average Starting Salary (Per Response I&E-RE-061)	$ 62,300	
2013 & 14 Average Overtime per Employee (Per GAS-RR-026)	10,350	
Total Wages	72,650	
Percentage charged Capital @40% (Per Response I&E-RE-061)	29,060	
Net Incremental Expense per Employee	$ 43,590	
Number of additional Heads	25	4/
	$ 1,081,125	

4/ Per Exhibit No. 104, Schedule No. 10 , Additional Head count

Additional Head count	$ 1,240,112
Company Addition expense per Head	50,000
Number of additional Heads	25

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Reflect FFRY NCSC Shared Services Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/
1	FTY Budget For Additional Labor	$ 573,000
2	FFRY Budget For Additional Labor	582,000
3		
4	Total Additional Labor Amount	$ 1,155,000
5	Less: Expense Increase Related to Employees Formerly assigned to NFIT During FTY	227,020
6	Expense Increase Related to Employees Formerly assigned to NFIT During FFRY	74,084
7	FTY Merit Increase	186,000
8	FFRY Merit Increase	204,935
9		
10	CPA Amount Available for Increase in Headcount	$ 462,961
11	Increase in Employees Planed for FTY and FFRY	36
12		
13	Amount Per Employee	$ 12,860
14	Total Headcount Increase Through April 2015	25
15		
16	Amount Available for Increase in Headcount	$ 321,501
17	CPA Amount Available for Increase in Headcount	462,961
18		
19	CPA share of increase Costs	$ (141,460)
20	Adjustment to Remove Year Annualization of Employees	(69,397)
	Adjustment to O&M Expense	$ (210,857)

Notes
1/ Response to OCA-4-047.

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Schedule LKM-10

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Reflect FFRY NCSC NGD Operations Labor Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount
1	Company Adjustment to Annualize Labor	$ 111,874 1/
2		
3		
4	Adjustment to O&M Expenses	$ (111,874)

Notes:
1/ Per Exhibit No. 104, Schedule No. 2, Page 14.

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Schedule LKM-11

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Eliminate Profit Sharing & Stock Awards
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	CPA Employees	$ 243,720	1/
2			
3	NCSC Charges	191,703	1/
4			
5	Stock Awards related to NCSC	1,404,856	2/
6			
7	Adjustment to O&M Expenses	$ (1,840,279)	

Notes:
1/ Response to I&E -RE-014.
2/ Response to I&E-RE-064.

Docket No. R-2015-2468056
Schedule LKM-12

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Other Employee Benefits to Recognize Employee Level Expense
For the Rate Year Ending December 31, 2016

Line No.			Amount 1/	
1	Medical	$	3,075,610	
2	Dental		189,937	
3	Group Life		78,378	
4	Long-Term Disability		199,091	
5	Employee Assist Program		48,056	
6	Post Employment Benefits		-	
7	Thrift Plan		1,255,762	
8	Profit Sharing		-	
9				
10	Total FFRY Other Employee Benefits	$	4,846,834	
11	Number of Employees		633	2/
12				
13	Total FFRY Other Employee Benefits per Employee	$	7,657	
14	Average FFRY number of Employees		619	
15				
16	Total FFRY Other Employee Benefits per OCA	$	4,739,637	
17	Total FFRY Other Employee Benefits per Company		4,846,834	
18				
19	Adjustment to Other Employee Benefits	$	(107,197)	

Notes:
1/ Response to I&E -RE-014..
2/ Response to GA -RR -26.

Docket No. R-2015-2468056
Schedule LKM-13

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Normalize Injuries & Damages Expense
For the Rate Year Ending December 31, 2016

Line No.		Annual Amounts 1/	Average Amount
1	December 2013 - November 2014	$ 261,045	$ -
2	December 2012 - November 2013	362,842	362,842
3	December 2011 - November 2012	325,681	325,681
4	December 2010 - November 2011	309,942	309,942
5	December 2009 - November 2010	726,103	-
6	Average Injuries and Damages Expense		332,822
7	Test Year Injuries and Damages Expense		429,150 2/
8	Adjustment to Injuries and Damages Expense		$ (96,328)

Notes:
1/ Exhibit No. 4, Schedule No. 2, Page 11.
2/ Exhibit No.104, Schedule No. 2, Page 7.

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Reflect Annual Rent and Lease Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/	
1	FFRY Strabane Construction Office/Warehouse Lease Expense	$ 150,000	
2			
3	Annualization of York Lease Starting April 2016	13,587	2/
4			
5	Annualization of Training Center Lease Starting April 2016	200,808	2/
6			
7	Adjustment to O&M Expense	$ (364,395)	

Notes:
1/ Response to OCA-7-001.
2/ Exhibit No. 104, Schedule No. 2, Page 6.

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COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Depreciation Expense to Reflect 13 Month Average Plant in Service
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/	Composite Depreciation Rate 2/	Annual Depreciation
	Depreciable Plant			
1	Underground Storage Plant Depreciable Balance	$ 6,004,522	2.67%	$ 160,321
2				
3	Distribution Plant Depreciable Balance	1,767,258,584	2.37%	41,884,028
4				
5	General Plant Depreciable Balance	25,355,304	2.41%	611,063
6				
7	Annual Depreciation Expense Subtotal			$ 42,655,412
8				
9	Amortizable Plant			
10	Miscellaneous Intangible Plant	$ 23,471,326	15.11%	3,547,114
11				
12	Total Depreciation and Amortization Expense per OCA			$ 46,202,526
13				
14	Total Depreciation and Amortization Expense per Company			50,115,986 2/
15				
16	Adjustment to Depreciation & Amortization Expense			$ (3,913,460)

Notes:
1/ Calculated based on data provided in Response to OCA-5-003.
2/ Company Exhibit No. 105, Pages 7 - 9.

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Payroll Taxes to Reflect Changes in Labor Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/
1	OCA Adjustment to Labor Expense	$ (1,138,592)
2	FICA Tax Rate	6.20%
3		
4	Adjustment to FICA Taxes	$ (70,593)
5		
6	OCA Adjustment to Labor Expense	$ (1,138,592)
7	Medicare Tax Rate	1.45%
8		
9	Adjustment to Medicare Taxes	$ (16,510)
10		
11	Adjustment to Taxes Other Income	$ (87,102)
12		

Notes:
1/ Schedule LKM-9.

Appendix A

LAFAYETTE K. MORGAN, JR.

Mr. Morgan was previously a Senior Regulatory Analyst with Exeter Associates, Inc., and now serves as a consultant to Exeter. At Exeter, Mr. Morgan has been involved in the analysis of the operations of public utilities with particular emphasis on rate regulation. He has reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination. This work included natural gas, water, electric, and telephone utilities.

Education and Qualifications

B.B.A. (Accounting) – North Carolina Central University, 1983

M.B.A. (Finance) – The George Washington University, 1993

C.P.A. – Licensed in the State of North Carolina (Inactive status)

Previous Employment

1990-1993	Senior Financial Analyst Potomac Electric Power Company Washington, D.C.
1984-1990	Staff Accountant North Carolina Utilities Commission – Public Staff Raleigh, NC

Professional Experience

As a Staff Accountant with the North Carolina Utilities Commission – Public Staff, Mr. Morgan was responsible for analyzing testimony, exhibits, and other data presented by parties before the Commission. In addition, he performed examinations of the books and records of utilities involved in rate proceedings and summarized the results into testimony and exhibits for presentation before the Commission. Mr. Morgan also participated in several policy proceedings involving regulated utilities.

As a Senior Financial Analyst with Potomac Electric Power Company, Mr. Morgan prepared cost of service, rate base, and ratemaking adjustments supporting the Company's request for revenue increases in its retail jurisdictions.

Expert Testimony

of Lafayette K. Morgan, Jr.

Kings Grant Water Company (North Carolina Utilities Commission, Docket No. W-250, Sub 5), 1984. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

W.D. & J.T. Billingsley (North Carolina Utilities Commission, Docket No. W-632, Sub 1), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Northwood Water Company (North Carolina Utilities Commission, Docket No. W-690, Sub 1), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Emerald Village Water System (North Carolina Utilities Commission, Docket No. W-184, Sub 3), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

General Telephone Company of the South (North Carolina Utilities Commission, Docket No. P-19, Sub 207), July 1986. Presented testimony on the level of cash working capital allowance on behalf of the North Carolina Utilities Commission – Public Staff.

Heins Telephone Company (North Carolina Utilities Commission, Docket No. P-26, Sub 93), November 1986. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Carolina Power and Light Company (North Carolina Utilities Commission, Docket No. E-2, Sub 537), March 1988. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Public Service Company of North Carolina, Inc. (North Carolina Utilities Commission, Docket No. G-5, Sub 246), August 1989. Presented testimony on rate base, cash working capital allowance, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Conestoga Telephone and Telegraph Company (Pennsylvania Public Utility Commission, Docket No. I-00920015), September 1993. Presented testimony on cost of service on behalf of the Pennsylvania Office of Consumer Advocate.

Louisiana Power and Light Company (Louisiana Public Service Commission, Docket No. U-20925), February 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

Expert Testimony

of Lafayette K. Morgan, Jr.

South Central Bell Telephone Company – Louisiana (Louisiana Public Service Commission, Docket No. U-17949, Subdocket E), June 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

Apollo Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953378), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Carnegie Natural Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953379), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112), September 1995. Presented testimony rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Virginia-American Water Company (Virginia State Corporation Commission, Case No. PUE-950003), March 1996. Presented testimony on rate base and cost of service issues on behalf of the City of Alexandria.

GTE North, Inc. Interconnection Arbitration (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

United Cities Gas Company (Georgia Public Service Commission, Docket No. 6691-U), October 1996. Presented testimony on rate base and cost of service issues on behalf of the Office of Governor, Consumer Utility Counsel Division.

GTE North, Inc. (Pennsylvania Public Utility Commission, Docket Nos. R-00963666 and R-00963666C001), February 1997. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

Consumers Maine Water Company (Maine Public Utilities Commission, Docket No. 96-739), May 1997. Presented testimony on rate base, cost of service, and rate of return issues on behalf of the Maine Office of the Public Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00973944), July 1997. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

Pennsylvania-American Water Company – Wastewater Operations (Pennsylvania Public Utility Commission, Docket No. R-00973973), July 1997. Presented testimony on rate base, cost of service, depreciation, and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Jackson Purchase Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-224), December 1997. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of the Attorney General.

Henderson Union Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-220), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of the Attorney General.

Green River Electric Corporation (Kentucky Public Service Commission, Case No. 97-219), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of the Attorney General.

Western Kentucky Gas Company (Kentucky Public Service Commission, Case No. 99-070), November 1999. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of the Attorney General.

American Broadband, Inc. (Rhode Island Public Utilities Commission, Docket No. 2000-C-3), June 2000. Presented report and testimony on the Company's financing plan on behalf of the Rhode Island Division of Public Utilities and Carriers.

PPL Utilities (Pennsylvania Public Utility Commission, Docket No. R-00005277), October 2000. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Oil and Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00005459), October 2000. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pike County Light & Power Company (Pennsylvania Public Utility Commission, Docket No. P-00011872), May 2001. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Vermont Gas Systems, Inc. (Vermont Public Service Board, Docket No. 6495), June 2001. Presented testimony on rate base and cost of service issues on behalf of the Vermont Public Service Department.

Expert Testimony

of Lafayette K. Morgan, Jr.

Community Service Telephone Company (Maine Public Utilities Commission, Docket No. 2001-249), July 2001. Presented joint testimony on rate base and cost of service issues on behalf of the Maine Office of the Public Advocate.

West Virginia-American Water Company (Public Service Commission of West Virginia, Docket No. 01-0326-W-42-T), August 2001. Presented testimony on rate base and cost of service issues on behalf of the Consumer Advocate Division.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00016750) February 2002. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois-American Water Company (Illinois Commerce Commission, Docket No. 02-0690) January 2003. Presented testimony on cost of service issues on behalf of Citizens Utility Board.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00027983), February 2003. Presented testimony addressing surcharge mechanism to recover security costs on behalf of the Pennsylvania Office of Consumer Advocate.

FairPoint New England Telephone Companies (Maine Public Utilities Commission, Docket Nos. 2002-747, 2003-34, 2003-35, 2003-36, and 2003-37), June 2003. Presented testimony on rate base and cost of service issues on behalf of the Maine Office of the Consumer Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00038304), August 2003. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

PPL Electric Utilities Corporation (Pennsylvania Public Utility Commission, Docket No. R-00049255), June 2004. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Entergy Louisiana, Inc. (Louisiana Public Service Commission, Docket No. U-20925 RRF 2004), August 2004. Presented testimony on rate base and cost of service issues on behalf of the Louisiana Public Service Commission Staff.

Vectren Energy Delivery of Indiana (Indiana Utility Regulatory Commission, Cause No. 42598), September 2004. Presented testimony on O&M expense issues on behalf of the Indiana Office of Utility Consumer Counselor.

Expert Testimony

of Lafayette K. Morgan, Jr.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-00049656), December 2004. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Block Island Power Company (Rhode Island Public Utilities Commission, Docket No. 3655), April 2005. Presented testimony on cash working capital on behalf of the Rhode Island Division of Public Utilities & Carriers.

Verizon New England, Inc. (Maine Public Utilities Commission, Docket No. 2005-155), September 2005. Presented joint testimony with Thomas S. Catlin on rate base and cost of service issues on behalf of the Maine Office of the Public Advocate.

T.W. Phillips Oil and Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00051178), May 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Duquesne Light Company (Pennsylvania Public Utility Commission, Docket No. R-00061346), July 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Company (Pennsylvania Public Utility Commission, Docket No. R-00061493), September 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Southern Indiana Gas & Electric Co. (Indiana Utility Regulatory Commission, Cause No. 43112), January 2007. Presented testimony on rate base and cost of service issues on behalf of the Indiana Office of Utility Consumer Counsel.

PPL Electric Utilities (Pennsylvania Public Utility Commission, Docket No. R-00072155), July 2007. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Aqua Pennsylvania, Inc. (Pennsylvania Public Utility Commission, Docket No. R-00072711), February 2008. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission, Docket No. R-2008-2029325), October 2008. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission, Docket No. 4026), April 2009. Presented testimony on rate base and cost of service issues on behalf of the Rhode Island Division of Public Utilities and Carriers.

Maryland-American Water Company (Maryland Public Service Commission, Case No. 9187), July 2009. Presented testimony on rate base and cost of service issues on behalf of the Maryland Office of People's Counsel.

Monongahela Power Company & The Potomac Edison Company, both d/b/a Allegheny Power Company (West Virginia Public Service Commission, Case No. 09-1352-E-42T), February 2010. Presented testimony on rate base and cost of service issues on behalf of the West Virginia Consumer Advocate Division.

PPL Electric Utilities (Pennsylvania Public Utility Commission, Docket No. R-2010-2161694), June 2010. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Other Projects

Texas Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP93-106). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP93-36). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Texas Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP94-423). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Lafourche Telephone Company (Louisiana Public Service Commission, Docket No. U-21181). Analysis and investigation of earnings and appropriate rate of return on behalf of the Louisiana Public Service Commission Staff.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP95-326). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Pymatuning Independent Telephone Company (Pennsylvania Public Utility Commission, Docket No. R-00953502). Technical analysis and development of settlement position in the Company's rate case on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 96-0172). Technical analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 97-0157). Technical analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

TDS Telecom (Pennsylvania Public Utility Commission, Docket Nos. R-00973892 and R-00973893). Technical analysis regarding rate base, cost of service, rate design, and rate of return, and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Pennsylvania Office of Consumer Advocate.

Appalachian Power Company (Virginia State Corporation Commission, Case No. PUE 960301). Technical analysis regarding rate base and cost of service and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Virginia Office of the Attorney General.

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 97-580). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 98-0259). Technical Analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Maine Public Service Company (Maine Public Utilities Commission, Docket No. 98-577). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Bangor Hydro-Electric Company (Maine Public Utilities Commission, Docket No. 97-596). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

TDS Telecom (Maine Public Utilities Commission, Docket Nos. 98-894, 98-895, 98-904, 98-906, 98-911, and 98-912). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Mid-Maine Telecom (Maine Public Utilities Commission, Docket No. 2000-810). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Unitel, Inc. (Maine Public Utilities Commission, Docket No. 2000-813). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Hydraulics International, Inc. (Armed Services Board of Contract Appeals, ASBCA No. 51285). Technical analysis and support relating to the Economic Adjustment Clause claim on behalf of the Air Force Materiel Command.

Tidewater Telecom and Lincolnville Telephone Company (Maine Public Utilities Commission, Docket Nos. 2002-100 and 2002-99). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

TDS Telecom (Vermont Public Service Board, Docket No. 6576). Technical analysis regarding rate base, cost of service, and depreciation expense on behalf of the Vermont Department of Public Service.

CenterPoint Energy-Entex (Louisiana Public Service Commission, Docket No. U-26720, Subdocket A). Technical analysis regarding rate base and cost of service on behalf of the Louisiana Public Service Commission Staff.

CenterPoint Energy-Arkla (Louisiana Public Service Commission, Docket No. U-27676). Technical analysis regarding rate base and cost of service on behalf of the Louisiana Public Service Commission Staff.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to CLECO Power LLC Rate Stabilization Plan.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to CLECO Power LLC post-Katrina power purchases.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to Entergy Louisiana LLC recovery of storm damage costs.

OCA Statement No. 1-S

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2015-2468056**
	)	
Columbia Gas of Pennsylvania, Inc.	)	

SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

RECEIVED
2015 AUG -7 PM 12: 14
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SECRETARY'S BUREAU

July 28, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

OCA Stmt. 1-S
R-2015-2468056
8-4-15
Harrisburg JS

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I. Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Public Utilities Consultant working with Exeter Associates, Inc. (Exeter). Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. ARE YOU THE SAME LAFAYETTE MORGAN, JR. WHO PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to respond to the rebuttal testimonies of Columbia Gas of Pennsylvania's (Columbia's) witnesses Kimberly K. Cartella, Chun-Yi Lai, Kelley K. Miller, Panpilas W. Fischer, Matthew T. Hanson, Nicole M. Paloney, and John J. Spanos.

Q. ARE YOU PRESENTING ANY SCHEDULES WITH YOUR SURREBUTTAL TESTIMONY?

A. Yes. I have attached Schedules LKM-1S through LKM-16S to this testimony. These schedules present the OCA's updated position on Columbia's rate increase. Revisions have been made to certain adjustments to reflect additional information gained in the Company's rebuttal filing and changes Columbia made in its rebuttal filing. Based upon these changes, the OCA is recommending a decrease in revenues of $6,472,125.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of this testimony presents my responses to the claims made by the Company's witnesses in their rebuttal testimonies on the adjustments that I recommended in my direct testimony. To the extent that additional information has been provided that warrants a change in any of my adjustments, I will identify the change I am making and why I have made the change.

II. Profit Sharing and Stock Rewards Plans

Q. COMPANY WITNESS KIMBERLY CARTELLA DISAGREES WITH YOUR ADJUSTMENT TO THE PROFIT SHARING AND STOCK REWARDS PLAN. WOULD YOU PLEASE ADDRESS THE ISSUES SHE RAISED IN HER REBUTTAL TESTIMONY?

A. Yes. In my direct testimony, I recommend the disallowance of Columbia's profit sharing plan and the stock rewards plan because payment under those plans is based upon the achievement of earnings goals. In disagreeing with my adjustment, Ms. Cartella explains that both the profit sharing and the stock rewards plans are designed to make Columbia competitive with other employers for attracting qualified employees. She indicates that the Company relies on the advice of a global human resources consulting firm in setting, evaluating, and making changes to its employee compensation and benefits plans. She describes the profit sharing plan as an element of a balanced competitive benefits program. She concludes that the Company would be at a disadvantage without the ability to provide such forms of compensation, and states that offering stock-based compensation is an appropriate cost of doing business. The overall argument that Ms. Cartella appears to be making is that the two plans are normal compensation plans that are similar to compensation plans offered by other companies in the utility industry and the U.S. as a whole.

Q. WHAT IS YOUR RESPONSE TO MS. CARTELLA?

A. Ms. Cartella has misunderstood the nature of my adjustment. Her testimony focuses on the justification for these plans as she attempts to demonstrate that Columbia's incentive plans are similar to other companies. I am not recommending that these types of incentive compensation not be paid or that the program be discontinued. Rather, it is my position that these costs should not and need not be recovered from ratepayers because achieving the financial goals should be self-funding. In other words, the financial goals should be established at a level that provides the funds to pay the incentives. Therefore, the Commission should reject her position that these costs should be recovered in rates.

III. <u>Customer Attrition</u>

Q. COLUMBIA WITNESS CHUN-YI LAI IS CRITICAL OF YOUR ADJUSTMENT TO REFLECT THE MOST RECENT THREE-YEAR AVERAGE CUSTOMER ATTRITION. PLEASE RESPOND.

A. In my direct testimony, I explained that Columbia's sales volumes forecast used a 4-year average of customer attrition based on the years 2010 to 2013, and that I recommend that the most recent 3-year average should be used instead. Mr. Lai criticized my adjustment stating that my adjustment would result in a net change in customers that is higher than the historical average. He also claims my adjustment results in a net residential change that is higher than any year since 2006, implying that the 3-year average would result in an unreasonable net increase in customers. For commercial customers, witness Lai states that using the 3-year average rate that I recommend would result in a net growth of 118 customers. Mr. Lai compares the 118 customers to the 7-year average of net growth in customers of 114 and characterizes the 114 as significantly lower than the 118. In an attempt to support the Company's high residential customer attrition rate, he references a study that states that the national average of total housing stock being eliminated annually is -0.5 percent. He compares that rate to the Company's residential attrition rate of -0.4 percent, and concludes that the Company's attrition rate is reasonable. I recommend that the Commission reject each of Mr. Lai's arguments because the Company has used the data in an inconsistent manner that would lead to a misleading conclusion. Moreover, Mr. Lai has excluded more recent data in favor of stale data from the past recessionary period.

Q. WHY SHOULD THE COMMISSION REJECT MR. LAI'S ARGUMENTS RELATING TO THE HISTORICAL AVERAGES OF THE NET CHANGE IN RESIDENTIAL AND COMMERCIAL CUSTOMERS?

A. First, the data that Columbia describes as the 4-year average is actually a 9-year average for the period 2005 to 2013. I have attached the Company's response to OCA 5-008 as Exhibit OCA 1S-1, which shows that the average annual attrition rate for the four years 2010 to 2013 to be -0.3 percent, not -0.4 percent as the Company states in the response. I have also attached the Company's response to OCA 9-001(b) as Exhibit OCA 1S-2, in which Columbia admits that the data is a 9-year average.

Second, the Company is inconsistent and "cherry picking" which data to use. While it used a 9-year average for residential customers, it used a 3-year average for commercial customers. Moreover, the Company chose to ignore the 2014 data completely. As can be seen in the response to OCA 5-008, page 2, the use of the 2014 data would result in a lower customer attrition rate. There has been no explanation of why the 2014 data should be ignored, even in Mr. Lai's criticism of my 3-year average (which includes 2014).

Third, Mr. Lai chose to use stale data that are not representative of current economic conditions. The nine years that Mr. Lai used includes the period which some economists have referred to as the "great recession" of 2007 to 2009. Accordingly, in the data presented in the response to OCA 5-008, one can see a decline in customer additions during that exact period. Hence, the 2,891 additional customers that Mr. Lai claims would result when my customer attrition rate is used is not as far-fetched as he implies, especially considering that in 2005 the increase was 2,466; in 2006 it was 3,454; and in 2014 (which was ignored by Mr. Lai) it was 2,505.

Finally, Mr. Lai refers to a U.S. Energy Information Administration (EIA) document and concludes that the Company's -0.4 percent residential attrition is consistent with the -0.5 percent annual loss of housing stock. Although the document appears to be published in 2014, the data in the document on which Mr. Lai is relying is from 2009 — five years ago. Again, this is stale data being used to justify the use of a 9-year average. Moreover, the data is national data. If Mr. Lai wants to link the drop in housing stock to Columbia's customer count, that data should be regional data.

IV. Weather Normalization Revenues

Q. MR. LAI DISAGREES WITH YOUR ADJUSTMENT TO REVENUE TO REFLECT THE UPDATED HEATING DEGREE DAYS IN THE WEATHER NORMALIZATION COMPONENT OF THE ANNUAL REVENUES. PLEASE COMMENT.

A. Mr. Lai pointed out that in my adjustment to reflect updated heating degree days for the weather normalization component of Columbia's annual revenue, I did not properly reflect all components that should have been included. In the Company's rebuttal filing, it has reflected all of the necessary components, and the adjustment has been reflected in Columbia's revised claim. I have accepted the Company's revisions, so there is no disagreement between the OCA and Columbia on this issue.

V. <u>Injuries and Damages Expense</u>

Q. COLUMBIA WITNESS KELLEY MILLER DISAGREED WITH YOUR ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE. PLEASE ADDRESS HER COMMENTS ON YOUR TESTIMONY.

A. In my direct testimony, I recommended an adjustment to Injuries and Damages expense to reflect a methodology similar to that used by the Company for budgeting purposes. In the response to OCA 4-031, Columbia states:

> [t]o determine the amount to be budgeted for the FTY and the FFRY Columbia reviews the actual incurred per book expense accrual for Injuries and Damages for the last 5 years. Columbia drops the highest and lowest expense years out of the analysis and takes an average of the remaining years to determine the budgeted amount for all future years.

I have used the same approach; the only difference is that I have used the actual claims instead of accrued expenses.

Ms. Miller disagrees with the approach I have taken because, in her opinion, the 5-year average takes into account fluctuations from year to year, the removal of the 5-year average is counter to the reason the 5-year average is used, and my approach is inherently unfair because Columbia would be denied a reasonable opportunity to recover its Injuries and Damages costs. She also states that by not using the deflators, I have not reflected costs at the 2016 level. I will address each of her points of disagreement. Based on my explanations, I recommend the Commission reject Ms. Miller's claims.

Q. DOES THE APPROACH YOU HAVE USED RECOGNIZE FLUCTUATIONS FROM YEAR TO YEAR?

A. Yes. After removing the unusual years, both the high and the low, the remaining 3-year average recognizes yearly fluctuations and represents a normalized level of expense. In ratemaking, one of the goals for expenses is to determine a normal ongoing level. As a method of determining the normal ongoing level, the Company has typically used the most recent 3-year average. Two exceptions are the 9-year average used for residential customer attrition and the 5-year average used for Injuries and Damages. Since I have decided not to apply price deflators (which I will address later), I chose to moderate the effect of my adjustment by not using the most recent 3-year average. As can be seen in the response to OCA 5-010, attached as Exhibit OCA 1S-3, the most recent 3-year average would have been less than the 3-year average I have used because it would have been skewed by the unusually low amount for the 12 months ended November 2014. Another way to look at this is that I have biased my calculation in the Company's favor in an attempt to be reasonable.

Q. DOES YOUR APPROACH RUN COUNTER TO THE 5-YEAR AVERAGE?

A. No. Presumably, the 5-year average was adopted to derive a normal ongoing level of expenses. My approach is consistent with that premise. The issue here is whether the Company should be allowed to be inconsistent when it comes to ratemaking and budgeting (on which the future test years are based). Both methods provide an ongoing level of expense, so the Company should not be allowed to pick and choose in order to make costs higher for ratemaking. The difference is that the 5-year approach that Ms. Miller advocates would cause rates to be unnecessarily higher. The use of budgeted amounts for future test years assumes that budgets are accurate. Ms. Miller has not provided a compelling reason as to why different methods should be used to determine these costs for ratemaking and budgeting. The use of the 3-year average, after removing the highest and lowest cost, does not put the Company at risk for recovering these costs, as I will explain later, but more importantly, it is consistent with the method used for budgeting.

Q. IS YOUR APPROACH INHERENTLY UNFAIR, CAUSING COLUMBIA TO BE DENIED A REASONABLE OPPORTUNITY TO RECOVER ITS INJURIES AND DAMAGES COSTS?

A. No. On page 4 of Ms. Miller's rebuttal testimony, she admits that Columbia "is now filing annual rate cases and it anticipates filing annual rate cases in the near future." As I demonstrate in my direct testimony, the amount I have included in expenses under my approach is higher than the expense recorded by the Company in each of the last three years, and higher than the average actual claim payments made during the last three years. If Injuries and Damages costs begin to increase above what has been reflected in the last three years, they will be captured in the average costs that will be included in the annual rate cases the Company plans to file. Hence, the risk of under-recovery is minimized and there is no unfair treatment to the Company. Conversely, these are not costs that are trued-up at the end of the period. Therefore, if unnecessarily higher levels of cost are included in rates, they will not be refunded. Consequently, it is the ratepayers who would face an unfair treatment.

Q. MS. MILLER STATES THAT BY NOT USING THE DEFLATORS, YOU HAVE NOT REFLECTED COSTS AT THE 2016 LEVEL. IS THAT VALID?

A. No. The Injuries and Damages costs that are included are primarily claims for which the Company is only responsible for the first $25,000. These are not costs for the same goods and services (e.g., materials and supplies) that the Company purchases routinely from year to year. In the response to OCA 4-028, the Company acknowledges that Injuries and Damages expense fluctuates from year to year, and from the costs presented in the response to OCA 5-010 (Exhibit OCA 1S-3), one can clearly see that these are not costs that steadily increase from year to year.

VI. Accumulated Deferred Income Taxes

Q. COLUMBIA WITNESS PANPILAS W. FISCHER HAS TAKEN ISSUE WITH TWO ASPECTS OF YOUR ADJUSTMENT TO REFLECT 13-MONTH AVERAGE ACCUMULATED DEFERRED INCOME TAXES. PLEASE RESPOND TO HER COMMENTS.

A. Although she disagrees with the use of the 13-month rate base adjustment, Ms. Fischer has identified two inadvertent errors in my presentation of the 13-month Accumulated Deferred Income Tax (ADIT) balance. I have accepted the changes Ms. Fischer has identified as necessary to properly reflect ADIT balance, and have presented those changes on Schedule LKM-5S. As a result, the adjustment to reflect the 13-month average ADIT is an increase to rate base of $9,908,897.

VII. Labor Expenses

Q. COLUMBIA WITNESS MATTHEW T. HANSON IS CRITICAL OF YOUR ADJUSTMENT TO LABOR. PLEASE RESPOND.

A. In stating his disagreement with my labor adjustment, Mr. Hanson has made a number of claims that demonstrate that he has misunderstood my adjustment and the ratemaking process. First, he claims that I referred to Columbia's response to I&E-RE-26 as support for my adjustment. Mr. Hanson has clearly misunderstood my comments. The reference to I&E-RE-26 was made to demonstrate support for my statement that labor costs were budgeted as a separate budget element. In the response to the follow-up data request, OCA 7-008, Columbia confirmed labor costs are a separate budget element. Therefore, I continue to question the additional training costs given that an amount was already included in the FFRY for new employees labor. The annual costs of labor for those employees was already included, so there is no need to include an additional amount of labor for training those same employees. If so, it would imply that the number of hours worked by those employees in the year was the sum of their normal work hours plus "extra" hours for training. In other words, Mr. Hanson is claiming a new employee would be working his or her normal 40-hour week plus extra hours that would be solely training time. In my opinion, this is not likely to be the case; therefore, I do not believe the inclusion of the $519,361 is justified.

Further in his rebuttal testimony, Mr. Hanson characterizes my adjustment as flawed and as a rudimentary mathematical calculation with no basis. Clearly, Mr. Hanson is ignoring one of the concepts of ratemaking. That is, costs are included in a rate case to establish an ongoing level and not to recover the cost of a specific year only. Once base rates are established, there is no requirement that the Company files another rate case within a specified time, unless the Commission makes that decision. Therefore, *it would be erroneous to establish rates on the premise of recovering the* specific costs of a given year.

Q. MR. HANSON IS ALSO CRITICAL OF YOUR ADJUSTMENT TO NCSC SHARED SERVICES LABOR. PLEASE RESPOND.

A. Mr. Hanson states that my adjustment to limit the number of new employees to the April 2015 level substantially understates the employee count, and is contrary to the forecasting process to limit the number of new employees to the experienced additions only. He claims that there is no basis for the adjustment that I have made.

It is important to point out that the cost of service is not strictly budget or forecast driven, or else there would be no ratemaking adjustments. The costs that are included in expenses for ratemaking are intended to be representative of the ongoing level of costs. It is normal to expect a level of vacancies every year due to employee turnover. Hence, to include the cost of all positions would assume the Company operated at full complement of employees, which is not usually the case.

VIII. Depreciation Expense

Q. IN HIS REBUTTAL TESTIMONY, WITNESS JOHN J. SPANOS IS CRITICAL OF YOUR ADJUSTMENT TO THE COMPANY'S DEPRECIATION EXPENSE. PLEASE RESPOND.

A. In my direct testimony, I adjusted depreciation expense to reflect the expense the Company will incur during the FFRY rather than the depreciation based on the end of the FFRY. I calculated the depreciation expense by applying the composite depreciation rate by functional plant (contained in Exhibit 105 of Columbia's filing) to the 13-month average balance of depreciable plant. Mr. Spanos is critical of the method I have used and has characterized it as an oversimplification of the depreciation expense calculation. I acknowledge that the manner in which I have calculated depreciation expense is not the method Mr. Spanos explains in his rebuttal testimony. In an effort to reduce the differences between the Company and the OCA, a data request has been submitted for Columbia to provide the necessary data to present the depreciation expense using the method described by Mr. Spanos. As of the filing date of this surrebuttal testimony, I have not received the response to this data request. I reserve the right to update my testimony, if necessary, upon receipt of the Company's response.

IX. Average Rate Base Valuation

Q. COLUMBIA WITNESS NICOLE M. PALONEY DISAGREES WITH YOUR ADJUSTMENT TO REFLECT THE AVERAGE RATE BASE AND CLAIMS THAT NOTHING IN ACT 11 SUPPORTS THE USE OF THE AVERAGE RATE BASE. PLEASE RESPOND.

A. According to Act 11, it is the Commission that is charged with implementing the Act. Accordingly, the Commission's Final Order in Docket No. M-2012-2293611, Implementation of Act 11 of 2012, states:

> Under this approach, the risks associated with regulatory lag will be substantially reduced because the new rates will be consistent with the test year used to establish those rates for at least the first year.

Hence, the use of a fully projected future test year is intended to allow rates to be set to recover the costs that will be incurred during the first year the rates are in effect. Plant investment is made in increments monthly, and the Company is allowed to earn a return on its investment as it is incurred during the FFRY. The average rate base reflects how the actual investment in plant is incurred during the FFRY. In contrast, the end of period valuation would allow the Company to over-earn its allowed return because it treats the investment as if it were incurred during the entire FFRY. Consequently, the Company would earn a return on the investment before it is incurred.

Q. WOULD YOU RESPOND TO WITNESS PALONEY ON THE USE OF THE DSIC AND THE USE OF THE AVERAGE RATE BASE?

A. Yes. Ms. Paloney states in her rebuttal testimony that the use of any valuation other than year-end for rate base would mean that a significant portion of the total investment made during the FFRY would not be recovered in base rates and would be eligible for DSIC recovery prior to the end of the FFRY. She argues that if the average rate base valuation is adopted, the Company should be granted specific authorization to implement a quarterly DSIC during the FFRY.

I believe that the proper way to establish rates in this proceeding is for the rates to be based on the costs that will be incurred during the first year the rates are in effect so that the Company has an opportunity to earn its allowed return. The availability of the DSIC to recover eligible investment should not be used to justify setting rates to generate an excessive return. If the Company meets the earnings test as well as the other criteria for recovery of eligible investment under the DSIC, then it would be proper to recover that investment at that point in time.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

210680

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)
)
v.) Docket No. R-2015-2468056
)
Columbia Gas of Pennsylvania, Inc.)

SCHEDULES ACCOMPANYING THE SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

July 28, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Operating Income
For the Rate Year Ending December 31, 2016

Line No.		Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
	Operating Revenues					
1	Base Revenues (Incl. Transportation)	$ 311,042,312	$ 572,053	$ 311,614,365	$ (6,456,159)	$ 305,158,206
2	Fuel Revenues	190,811,611	-	190,811,611	-	190,811,611
3	Rider USP	27,722,803	-	27,722,803	-	27,722,803
4	Gas Procurement Charge	2,327,248	-	2,327,248	-	2,327,248
5	Merchant Function Charge	1,758,148	-	1,758,148	-	1,758,148
6	Rider CC	41,954	-	41,954	-	41,954
7	Rider CAC	-	-	-	-	-
8	Total Sales and Transportation Revenues	$ 533,704,076	$ 572,053	$ 534,276,129	$ (6,456,159)	$ 527,819,970
9	Off System Sales Revenue	-	-	-	-	-
10	Late Payment Fees	1,318,074	-	1,318,074	(15,966)	1,302,108
11	Other Operating Revenues (Excl. Transport.)	584,914	-	584,914	-	584,914
12	Total Operating Revenues	$ 535,607,064	$ 572,053	$ 536,179,117	$ (6,472,125)	$ 529,706,992
13						
14	Operating Revenue Deductions					
15	Gas Supply Expense	$ 190,811,611	$ 298,980	$ 191,110,591	$ -	$ 191,110,591
16	Off System Sales Expense	-	-	-	-	-
17	Gas Used in Company Operations	-	-	-	-	-
18	Operating and Maintenance Expense	177,301,481	(3,719,522)	173,581,959	(84,523)	173,497,436
19	Depreciation and Amortization Exp.	50,148,566	(3,946,040)	46,202,526	-	46,202,526
20	Net Salvage Amortized	4,635,342	-	4,635,342	-	4,635,342
21	Taxes Other Than Income	3,221,085	(87,102)	3,133,983	-	3,133,983
22	Total Operating Revenue Deductions	426,118,085	(7,453,685)	418,664,400	(84,523)	418,579,877
23						
24	Operating Income Before Income Taxes	109,488,979	8,025,738	117,514,717	(6,387,602)	111,127,115
25						
26	Income Taxes	29,429,355	3,469,519	32,898,874	(3,526,394)	29,372,481
27	Investment Tax Credit	(360,240)	-	(360,240)	-	(360,240)
28						
29	Net Operating Income	$ 80,419,864	$ 4,556,219	$ 84,976,083	$ (2,861,208)	$ 82,114,874
30						
31	Rate Base	$ 1,325,257,238		$ 1,221,947,529		$ 1,221,947,529
32						
33	Return On Rate Base	6.07%		6.95%		6.72%

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Revenue Increase at OCA Rate of Return
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	Adjusted Rate Base	$ 1,221,947,529	Schedule LKM-2, Page 2
2	Required Rate of Return	6.720%	
3			
4	Net Operating Income Required	$ 82,114,874	
5	Net Operating Income at Present Rates	84,976,083	Schedule LKM-1, Page 1
6			
7	Income Deficiency/(Surplus)	$ (2,861,209)	
8	Revenue Multiplier	2.26202502	
9			
10	Required Change in Company Revenue	$ (6,472,125)	
11			
12	Proposed Revenue Change	$ (6,472,125)	
13	Less: Uncollectibles	(84,523)	
14	Plus: Late Payment		
15	Income Before State Taxes	$ (6,387,602)	
16	State Income Tax Effect Tax Rate		
17	Less: State Income Tax	(1,985,743)	
18	Income Before Federal Taxes	$ (4,401,859)	
19	Federal Income Tax @35%	(1,540,651)	
20			
21	Net Income Surplus/(Deficiency)	$ (2,861,208)	

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Rate Base
For the Rate Year Ending December 31, 2016

	Amount per Company Filing	OCA Rate Base Adjustments	Amount After OCA Adjustments
Property Plant and Equipment			
Gas Plant in Service	$ 1,945,029,486	$ (120,937,277)	$ 1,824,092,209
Construction Work in Progress	-	-	-
Gas Stored Underground - Non Current	3,794,693	-	3,794,693
Depreciation Reserve	(386,611,458)	7,718,671	(378,892,787)
Accumulated Provision Gas Lost - Underground Storage	(163,467)	-	(163,467)
Net Plant in Service	$ 1,562,049,254	$ (113,218,606)	$ 1,448,830,648
Working Capital			
Materials & Supplies	$ 648,987	$ -	$ 648,987
Prepayments	2,107,010	-	2,107,010
Gas Stored Underground	58,489,294	-	58,489,294
Cash Allowance	-	-	-
Total Working Capital	$ 61,245,291	$ -	$ 61,245,291
Deferred Income Taxes			
Income Taxes	$ 8,949,377	$ -	$ 8,949,377
Depreciation	(303,643,348)	9,908,897	(293,734,451)
Other	-	-	-
Total Deferred Income Taxes	$ (294,693,971)	$ 9,908,897	$ (284,785,074)
Customer Deposits	(3,131,607)	-	(3,131,607)
Customer Advances for Construction	(211,729)	-	(211,729)
Total Rate Base	$ 1,325,257,238	$ (103,309,709)	$ 1,221,947,529

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Rate Base Adjustments
For the Rate Year Ending December 31, 2016

	Source	Amount
Rate Base per Company Filing	Schedule LKM-2, Page 1	$ 1,325,257,238
OCA Adjustments:		
Plant In Service	Schedule LKM-6	$ (120,937,277)
Accumulated Depreciation	Schedule LKM-6	7,718,671
Accumulated Deferred Income Taxes	Schedule LKM-6	9,908,897
Total Ratemaking Adjustments		$ (103,309,709)
Adjusted Rate Base per OCA		$ 1,221,947,529

Docket No. R-2015-2468056
Schedule LKM-3S
Page 1 of 2

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending December 31, 2016

Line No.		Amount	Source
1	Operating Income Before Income Taxes per Company	$ 109,488,979	Exhibit No. 102, Schedule 3, Page 3
2			
3	OCA Adjustments:		
4	Sales Attrition	$ 273,073	Schedule LKM-6S
5	Weather Normalization	-	Schedule LKM-7S
6	CPA Payroll	1,138,592	Schedule LKM-8S
7	NCSC Shared Services	210,857	Schedule LKM-9S
8	NCSC NGD	111,874	Schedule LKM-10S
9	Profit Sharing	1,840,279	Schedule LKM-11S
10	Employee Benefits	107,197	Schedule LKM-12S
11	Injuries and Damages	96,328	Schedule LKM-13S
12	Annual Rents and Leases	214,395	Schedule LKM-14S
13	Depreciation & Amortization	3,946,040	Schedule LKM-15S
14	FICA Taxes	87,102	Schedule LKM-16S
15	Total OCA Adjustments	$ 8,025,738	
16			
17	Operating Income Before Income Taxes per OCA	$ 117,514,717	

COLUMBIA GAS OF PENNSYLVANIA INC.

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending December 31, 2016

Line No.		Operating Revenues	O&M Expenses	Depreciation & Amortization	Taxes Other Than Income	Operating Income Before Income Taxes
1	Amount per Company	$ 535,607,064	$368,113,092	$ 54,783,908	$ 3,221,085	$ 109,488,979
2						
3	OCA Adjustments:					
4	*Sales Attrition*	$ 572,053	$ 298,980	$ -	$ -	$ 273,073
5	Weather Normalization	-	-	-	-	-
6	CPA Payroll		(1,138,592)	-	-	1,138,592
7	NCSC Shared Services	-	(210,857)	-	-	210,857
8	NCSC NGD	-	(111,874)	-	-	111,874
9	Profit Sharing	-	(1,840,279)	-	-	1,840,279
10	Employee Benefits	-	(107,197)	-	-	107,197
11	Injuries and Damages	-	(96,328)	-	-	96,328
12	Annual Rents and Leases	-	(214,395)	-	-	214,395
13	Depreciation & Amortization	-	-	(3,946,040)	-	3,946,040
14	FICA Taxes	-	-	-	(87,102)	87,102
15						
16	Total OCA Adjustments	$ 572,053	$ (3,420,542)	$ (3,946,040)	$ (87,102)	$ 8,025,738
17						
18	Total Adjusted Income Before Income Taxes	$ 536,179,117	$364,692,550	$ 50,837,868	$ 3,133,983	$ 117,514,717

Docket No. R-2015-2468056
Schedule LKM-4s

COLUMBIA GAS OF PENNSYLVANIA INC.

Reconciliation of State and Federal Income Taxes
For the Rate Year Ending December 31, 2016

Line No.		Amount Per Company at present rates	OCA Adjustments	OCA Adjusted Amounts at Present Rates	Pro Forma Change in Revenues	Amounts After Change in Revenues
1	Net Operating Income Before Income Taxes	$ 109,488,979	$ 8,025,738	$ 117,514,717	$ (6,387,602)	$ 111,127,115
2						
3	Interest Expense	31,806,174	335,859	32,142,033	-	32,142,033
4	Other Flow Through Adjustments	(57,199,167)	-	(57,199,167)	-	(57,199,167)
5	Deferral Adjustments	(58,946,444)	-	(58,946,444)	-	(58,946,444)
6						
7	Total Statutory Adjustments	$ (84,339,437)	$ 335,859	$ (84,003,578)	$ -	$ (84,003,578)
8	Pennsylvania Bonus Depreciation	(7,572,748)	-	(7,572,748)	-	(7,572,748)
9						
10	CNIT Taxable Income	$ 17,576,794	$ 8,361,597	$ 25,938,391	$ (6,387,602)	$ 19,550,789
11	Net Operating Loss Adjustment	5,273,039	-	5,273,039	13,489,703	18,762,742
12	Pennsylvania Taxable Income	$ 12,303,755	$ 8,361,597	$ 20,665,352	$ (19,877,305)	$ 788,047
13						
14	Pennsylvania Income Tax Payable @ 9.99%	1,229,145	835,324	2,064,469	(1,985,743)	78,726
15	*Deferred Tax on Inventory Adjustment*	1,717	-	1,717	-	1,717
16	Deferred Tax on Customer Advances	(52,820)	-	(52,820)	-	(52,820)
17	Total Pennsylvania Income Taxes	$ 1,178,042	$ 835,324	$ 2,013,366	$ (1,985,743)	$ 27,623
18						
19	Net Operating Income Before Income Taxes	$ 109,488,979	$ 8,025,738	$ 117,514,717	$ (6,387,602)	$ 111,127,115
20	Pennsylvania Income Tax Payable @ 9.99%	1,229,145	835,324	2,064,469	(1,985,743)	78,726
21	Total Statutory Adjustments	(84,339,437)	335,859	(84,003,578)	-	(84,003,578)
22	Taxable Income	$ 23,920,397	$ 7,526,274	$ 31,446,671	$ (4,401,859)	$ 27,044,811
23						
24	Federal Income Tax Payable @ 35%	8,372,139	2,634,196	11,006,335	(1,540,651)	9,465,684
25	Federal Deferred Tax @ 35%	20,631,255	-	20,631,255	-	20,631,255
26	Tax Refund Amortization	(681,571)	-	(681,571)	-	(681,571)
27	Flow Back of Excess Deferred Taxes	(88,396)	-	(88,396)	-	(88,396)
28	Effect of CNIT Deferred Tax on FIT	17,886	-	17,886	-	17,886
29	Net Federal Income Tax	$ 28,251,313	$ 2,634,196	$ 30,885,509	$ (1,540,651)	$ 29,344,858
	Calculation of Interest Deduction					
	Rate Base	$ 1,325,257,238		$ 1,221,947,529		$ 1,221,947,529
	Weighted Cost of Debt	2.40%		2.57%		2.57%
		$ 31,739,911	$ (335,859)	$ 31,404,051		$ 31,404,051

Docket No. R-2015-2468056
Schedule LKM-5S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Rate Base to Reflect 13-Month Average Balance for Plant and Related Items
For the Rate Year Ending December 31, 2016

Line No.		Balance Per Company at December 31, 2016 1/	13-Month Average Balance per OCA	OCA Adjustment
1	Plant In Service	$ 1,945,029,486	$ 1,824,092,209 2/	$ (120,937,277)
2				
3	Accumulated Depreciation	(386,737,768)	(379,019,097) 3/	7,718,671
4				
5	Net Plant	$ 1,558,291,718	$ 1,445,073,112	$ (113,218,606)
6				
7	Accumulated Deferred Income Taxes	(294,693,971)	(284,785,074) 4/	9,908,897
8				
9	Net Balance	$ 1,263,597,747	$ 1,160,288,038	$ (103,309,709)
10				
11				
12				
13				

14 Notes:
15 1/ Exhibit 108, Page 3
16 2/ Company Response to OCA-7-003.
17 3/ Company Response to OCA-7-005

18	4/ Account 190	$ 8,949,377	Exhibit 108, Schedule No. 8.
19	Less: Federal NOL Terminal Balance	2,590,812	Exhibit 108, Schedule No. 8.
20	Plus: Federal NOL 13-mo. Average	9,800,013	CPA witness Fischer Rebuttal, Page 3.
21	Account 190 adjusted to 13-month average	$ 16,158,578	
22	Account 282 adjusted to 13-month average	(300,943,652)	CPA witness Fischer Rebuttal, Page 2.
23	Revised ADIT Balance	$ (284,785,074)	

Docket No. R-2015-2468056
Schedule LKM-6S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Operating Revenues to Reflect 3-Year Average Customer Attrition
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	Residential Sales Service Revenues Based Upon 3-Year Average Attrition	$ 304,206,884	1/
2	Residential Sales Service Revenues Per Company	303,828,729	2/
3			
4	Adjustment to Residential Sales Service Revenues	$ 378,155	
5			
6	Small General Service Revenues Based Upon 3-Year Average Attrition	$ 86,628,242	1/
7	Small General Service Revenues Per Company	86,434,344	2/
8			
9	Adjustment to Small General Service Revenues	$ 193,898	
10			
11			
12	Total Adjustment to Operating Revenues	$ 572,053	
13			
14			
15	Adjustment to Cost of Gas Expense	$ 273,227	3/
16			
17	Adjustment to O&M Expense	$ 25,753	3/

Notes:
1/ Calculated based upon data provided in Response to OCA-9-002.
2/ Company Exhibit No. 103, Page 8 of 15.

3/	Base Revenues	$ 310,753,903	$ 311,021,009	$ 267,106
	Fuel Revenues	190,479,760	190,752,987	273,227
	Rider USP	27,644,938	27,670,691	25,753
	Gas Procurement Charge	2,322,967	2,326,491	3,524
	Merchant Function Charge	1,752,694	1,755,092	2,398
	Rider CC	41,900	41,945	45
	Rider CAC	-	-	-
	Total Sales Revenues	$ 532,996,162	$ 533,568,215	$ 572,053
	Late Payment Fees	1,318,074	1,318,074	-
	Other Operating Revenues	584,914	584,914	-
		$ 534,899,150	$ 535,471,203	$ 572,053

Schedule LKM-7S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Operating Revenues to Reflect Updated Weather Normalization through 2014
For the Rate Year Ending December 31, 2016

Line No.		Amount
1		
2		
3		
4		
5	**This adjustment was withdrawn because it was reflected in Compnay's Rebuttal Filing.**	
6	**See Witness Kelley K. Miller Rebuttal Testimony at page 2.**	
7		
8		
9		
10		
11		
12		

Notes:

Docket No. R-2015-2468056
Schedule LKM-8S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Annualize Payroll Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount Per Company 1/	Amount Per OCA	Adjustment
1	HTY Labor Expense	$ 25,550,026	$ 25,550,026	$ -
2				
3	Merit increase at 3 Percent	766,501	766,501	-
4				
5	Additional Headcount	1,240,112	1,081,125	(158,987)
6				
7	Training Initiatives	519,361	-	(519,361)
8				
9	FTY Labor Expense	$ 28,076,000	$ 27,397,652	$ (678,348)
10				
11	Merit increase at 3 Percent	842,280	821,930	(20,350)
12				
13	Additional Headcount	1,223,720	1,081,125	(142,595)
14				
15	FFRY Labor Expense Before Ratemaking Adjustment	$ 30,142,000	$ 29,300,707	$ (841,293)
16				
17	FFRY Labor Animalization	297,299 2/	-	(297,299)
18				
19	FFRY Labor Expense	$ 30,439,299	$ 29,300,707	$ (1,138,592)
20				
21				
22				

Notes:

1/ Exhibit No. 104, Schedule No. 10.

2/ Exhibit No. 104, Schedule No. 1, Page 4.

3/ Calculation of Average Annual salary

Average Starting Salary (Per Response I&E-RE-061)	$ 62,300	
2013 & 14 Average Overtime per Employee (Per GAS-RR-026)	10,350	
Total Wages	72,650	
Percentage charged Capital @40% (Per Response I&E-RE-061)	29,060	
Net Incremental Expense per Employee	$ 43,590	
Number of additional Heads	25	4/
	$ 1,081,125	

4/ Per Exhibit No. 104, Schedule No. 10 , Additional Head count

Additional Head count	$ 1,240,112
Company Addition expense per Head	50,000
Number of additional Heads	25

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Reflect FFRY NCSC Shared Services Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/
1	FTY Budget For Additional Labor	$ 573,000
2	FFRY Budget For Additional Labor	582,000
3		
4	Total Additional Labor Amount	$ 1,155,000
5	Less: Expense Increase Related to Employees Formerly assigned to NFIT During FTY	227,020
6	Expense Increase Related to Employees Formerly assigned to NFIT During FFRY	74,084
7	FTY Merit Increase	186,000
8	FFRY Merit Increase	204,935
9		
10	CPA Amount Available for Increase in Headcount	$ 462,961
11	Increase in Employees Planed for FTY and FFRY	36
12		
13	Amount Per Employee	$ 12,860
14	Total Headcount Increase Through April 2015	25
15		
16	Amount Available for Increase in Headcount	$ 321,501
17	CPA Amount Available for Increase in Headcount	462,961
18		
19	CPA share of increase Costs	$ (141,460)
20	Adjustment to Remove Year Annualization of Employees	(69,397)
	Adjustment to O&M Expense	$ (210,857)

Notes
1/ Response to OCA-4-047.

Docket No. R-2015-2468056
Schedule LKM-10S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Reflect FFRY NCSC NGD Operations Labor Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	Company Adjustment to Annualize Labor	$ 111,874	1/
2			
3			
4	Adjustment to O&M Expenses	$ (111,874)	

Notes:
1/ Per Exhibit No. 104, Schedule No. 2, Page 14.

Docket No. R-2015-2468056
Schedule LKM-11S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Eliminate Profit Sharing & Stock Awards
For the Rate Year Ending December 31, 2016

Line No.		Amount	
1	CPA Employees	$ 243,720	1/
2			
3	NCSC Charges	191,703	1/
4			
5	Stock Awards related to NCSC	1,404,856	2/
6			
7	Adjustment to O&M Expenses	$ (1,840,279)	

Notes:
1/ Response to I&E -RE-014.
2/ Response to I&E-RE-064.

Docket No. R-2015-2468056
Schedule LKM-12S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Other Employee Benefits to Recognize Employee Level Expense
For the Rate Year Ending December 31, 2016

Line No.			Amount 1/	
1	Medical	$	3,075,610	
2	Dental		189,937	
3	Group Life		78,378	
4	Long-Term Disability		199,091	
5	Employee Assist Program		48,056	
6	Post Employment Benefits		-	
7	Thrift Plan		1,255,762	
8	Profit Sharing		-	
9				
10	Total FFRY Other Employee Benefits	$	4,846,834	
11	Number of Employees		633	2/
12				
13	Total FFRY Other Employee Benefits per Employee	$	7,657	
14	Average FFRY number of Employees		619	
15				
16	Total FFRY Other Employee Benefits per OCA	$	4,739,637	
17	Total FFRY Other Employee Benefits per Company		4,846,834	
18				
19	Adjustment to Other Employee Benefits	$	(107,197)	

Notes:

1/ Response to I&E -RE-014..

2/ Response to GA -RR -26.

Docket No. R-2015-2468056
Schedule LKM-13S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Normalize Injuries & Damages Expense
For the Rate Year Ending December 31, 2016

Line No.		Annual Amounts 1/	Average Amount
1	December 2013 - November 2014	$ 261,045	$ -
2	December 2012 - November 2013	362,842	362,842
3	December 2011 - November 2012	325,681	325,681
4	December 2010 - November 2011	309,942	309,942
5	December 2009 - November 2010	726,103	-
6	Average Injuries and Damages Expense		332,822
7	Test Year Injuries and Damages Expense		429,150 2/
8	Adjustment to Injuries and Damages Expense		$ (96,328)

Notes:
1/ Exhibit No. 4, Schedule No. 2, Page 11.
2/ Exhibit No.104, Schedule No. 2, Page 7.

Docket No. R-2015-2468056
Schedule LKM-14S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Reflect Annual Rent and Lease Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount	1/
1	FFRY Strabane Construction Office/Warehouse Lease Expense	$ -	3/
2			
3	Annualization of York Lease Starting April 2016	13,587	2/
4			
5	Annualization of Training Center Lease Starting April 2016	200,808	2/
6			
7	Adjustment to O&M Expense	$ (214,395)	

Notes:
1/ Response to OCA-7-001.
2/ Exhibit No. 104, Schedule No. 2, Page 6.
3/ This line item was withdrawn because the costs has been revised in the Company's Rebuttal Testimony.

Docket No. R-2015-2468056
Schedule LKM-15S

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Depreciation Expense to Reflect 13 Month Average Plant in Service
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/	Composite Depreciation Rate 2/	Annual Depreciation
	Depreciable Plant			
1	Underground Storage Plant Depreciable Balance	$ 6,004,522	2.67%	$ 160,321
2				
3	Distribution Plant Depreciable Balance	1,767,258,584	2.37%	41,884,028
4				
5	General Plant Depreciable Balance	25,355,304	2.41%	611,063
6				
7	Annual Depreciation Expense Subtotal			$ 42,655,412
8				
9	Amortizable Plant			
10	Miscellaneous Intangible Plant	$ 23,471,326	15.11%	3,547,114
11				
12	Total Depreciation and Amortization Expense per OCA			$ 46,202,526
13				
14	Total Depreciation and Amortization Expense per Company			50,148,566 2/
15				
16	Adjustment to Depreciation & Amortization Expense			$ (3,946,040)

Notes:
1/ Calculated based on data provided in Response to OCA-5-003.
2/ Company Exhibit No. 105, Pages 7 - 9.

COLUMBIA GAS OF PENNSYLVANIA INC.

Adjustment to Payroll Taxes to Reflect Changes in Labor Expense
For the Rate Year Ending December 31, 2016

Line No.		Amount 1/
1	OCA Adjustment to Labor Expense	$ (1,138,592)
2	FICA Tax Rate	6.20%
3		
4	Adjustment to FICA Taxes	$ (70,593)
5		
6	OCA Adjustment to Labor Expense	$ (1,138,592)
7	Medicare Tax Rate	1.45%
8		
9	Adjustment to Medicare Taxes	$ (16,510)
10		
11	Adjustment to Taxes Other Income	$ (87,102)
12		

Notes:
1/ Schedule LKM-9.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2015-2468056
	)	
Columbia Gas of Pennsylvania, Inc.	)	

EXHIBITS ACCOMPANYING THE SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

July 28, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

Exhibit OCA 1S-1

Question No. OCA 5-008
Respondent: C.Y. Lai
Page 1 of 2

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

OCA – Set 5

Question No. OCA 5-008:

With regard to the calculation of customer attrition, please provide the supporting documentation showing the derivation of the various customer attrition rates presented in the Company's responses to:

a. I&E-RS-14
b. I&E-RS-15
c. I&E-RS-18
d. I&E-RS-19
e. I&E-RS-20
f. I&E-RS-21
g. I&E-RS-22
h. I&E-RS-23
i. I&E-RS-24
j. I&E-RS-25

Response:

a – j Please see the table below for the customer attrition rates experienced from the years 2005 – 2014. It shows the -0.2% residential attrition rate for 2014 as presented in the response to I&E-RS-14 and the -0.9% commercial attrition rate for 2014 as presented in the response to I&E-RS-15. For the purpose of this proceeding, a four year average attrition (2010 – 2013) was used to forecast the attrition customers in the Future Test Year and the Fully Forecasted Rate Year. The residential average was deemed to be low due to some unusually low values. Therefore, it was adjusted from -0.3% to -0.4%. The four year average attrition rate for commercial was -1.1%. The four year average customer attrition rates of -0.4% and -1.1% were used to forecast the attrition customers for residential and commercial, respectively, in I&E-RS-18 through I&E-RS-25. Please see the response to OCA-4-008 for explanation on the derivation of attrition customers.

Exhibit OCA 1S-1

Question No. OCA 5-008
Respondent: C.Y. Lai

	RESIDENTIAL					
CPA	Year-End Customers	Change	% Change	Additions	Attrition	% Total Attrition
2004	365,772					
2005	368,238	2,466	0.7%	5,206	(2,740)	-0.7%
2006	371,692	3,454	0.9%	4,863	(1,409)	-0.4%
2007	373,928	2,236	0.6%	3,258	(1,022)	-0.3%
2008	375,051	1,123	0.3%	2,932	(1,809)	-0.5%
2009	375,225	174	0.0%	2,361	(2,187)	-0.6%
2010	377,103	1,878	0.5%	2,465	(587)	-0.2%
2011	377,530	427	0.1%	2,260	(1,833)	-0.5%
2012	379,679	2,149	0.6%	2,712	(563)	-0.1%
2013	381,727	2,048	0.5%	3,210	(1,162)	-0.3%
2014	384,232	2,505	0.7%	3,333	(828)	-0.2%
Avg 4 Years (2010 - 2013)						-0.3%
Adjusted Avg 4 Years (2010 - 2013)						-0.4%

	COMMERCIAL					
CPA	Year-End Customers	Change	% Change	Additions	Attrition	% Total Attrition
2004	38,643					
2005	38,401	(242)	-0.6%	474	(716)	-1.9%
2006	38,139	(262)	-0.7%	461	(723)	-1.9%
2007	38,002	(137)	-0.4%	453	(590)	-1.5%
2008	37,712	(290)	-0.8%	514	(804)	-2.1%
2009	37,363	(349)	-0.9%	375	(724)	-1.9%
2010	37,283	(80)	-0.2%	329	(409)	-1.1%
2011	37,122	(161)	-0.4%	363	(524)	-1.4%
2012	37,171	49	0.1%	325	(276)	-0.7%
2013	37,137	(34)	-0.1%	389	(423)	-1.1%
2014	37,225	88	0.2%	424	(336)	-0.9%
Avg 4 Years (2010 - 2013)						-1.1%

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

OCA – Set 9

Question No. OCA 9-001:

Reference the Company's response to OCA-5-008.

a. Please explain why it is appropriate to use a 1-year customer attrition rate for the HTY but not for the FTY or the FFRY. Please provide all reasons why the 4-year average customer attrition is appropriate for the FTY and FFRT but not the HTY.

b. Please provide the empirical basis for concluding that the -0.3% attrition rate was "deemed to be low due to some unusually low values", and explain why the use of an average would not normalize the data.

c. Please provide the calculations showing the derivation of the adjusted average attrition rate of -0.4% from the average of -0.3% for Residential customers.

Response:

a. The attrition rate for the HTY was derived by taking the customer loss due to attrition through the year divided by the year-end customer count from the prior year. It is appropriate to use a 1-year customer attrition rate for the HTY due to the availability of actual known data at the time of rate case preparation. For the purpose of forecasting, the 4-year average is applied to the Future Test Year and the Fully Forecasted Rate year to derive a forecasted level that is representative of prior experiences because actual data is not yet known for those periods.

b. The empirical basis was a review of the history of Columbia;s customer attrition rate. The review included nine years of data which averaged -0.4%. In other words, the adjustment of the 4-year average put it at the level of the 9-year average.

Exhibit OCA 1S-2

Question No. OCA 9-001
Respondent: C.Y. Lai

c. The average was adjusted by adding a specified -0.1% to -0.3% to get to an adjusted level of -0.4%.

Exhibit OCA 1S-3

Question No. OCA 5-010
Respondent: K. Miller
Page 1 of 1

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

OCA – Set 5

Question No. OCA 5-010:

With regard to Injuries & Damages Expense for the 12 months ended November 30, 2014, and the two preceding years, please provide a breakdown of the total expense for each year by showing the amount credited to the Injuries & Damages reserve and the amount credited to accounts other than the Injuries & Damages Reserve (please identify the accounts).

Response:

Please see Table OCA-5-010 below for a breakdown of Injuries and Damages Expense for the 12 months ended November 30, 2014 and the two preceding years. Also see the response to OCA-5-011 for an explanation of the Injuries and Damages Reserve Liability.

Table OCA-5-010

Dates	Net Change in Reserve Liability	Payments	Total Expense
(1)	(2)	(3)	(4)
	$	$	$
December 2011 - November 2012	(69,844.00)	325,681.49	255,837.49
December 2012 - November 2013	(23,790.08)	362,842.24	339,052.16
December 2013 - November 2014	(20,066.00)	261,044.80	240,978.80

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Lafayette K. Morgan, Jr., hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 1-S, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: Lafayette Morgan Jr.
Lafayette K. Morgan, Jr.

Consultant Address: Exeter Associates, Inc.
Suite 300
10480 Little Patuxent Parkway
Columbia, MD 21044

DATED: July 28, 2015

OCA STATEMENT NO. 2

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
v. :
: **Docket No. R-2015-2468056**
:
Columbia Gas of Pennsylvania, Inc. :

DIRECT TESTIMONY
OF
AARON L. ROTHSCHILD

ON BEHALF OF
THE OFFICE OF CONSUMER ADVOCATE

RECEIVED
2015 AUG -7 PM 12 46
PA PUC
SECRETARY'S BUREAU

June 19, 2015

OCA Stmt. 2
R-2015-2468056
8-4-15
Harrisburg JS

Contents

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Aaron L. Rothschild and my address is 15 Lake Road, Ridgefield, CT 06877.

Q. WHAT IS YOUR OCCUPATION?

A. I am a financial consultant specializing in cost of capital.

Q. WHAT IS YOUR EDUCATION AND EXPERIENCE?

A. I have a B.A. (1994) degree from Clark University in mathematics and an M.B.A. (1996) from Vanderbilt University. I provided financial analysis in the telecom industry in the United States and Asia Pacific from 1996 to 2001 and I have prepared rate of return testimonies since 2002. See Appendix A for my resume.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the Office of Consumer Advocate (OCA) to provide my recommendations to the Commission in the Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") rate proceedings regarding their gas utility's 1) cost of equity, 2) capital structure, and 3) overall cost of capital.

II. SUMMARY OF CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend the following for the Company:

- An overall cost of capital of 6.72%.

- A cost of equity of 8.88%.

- A capital structure containing 46.75% common equity, 10.69% short-term debt and 42.57% long-term debt based on the average capital structure ratios of the Gas Group.

- A short-term debt cost rate of 2.86%

- A long-term debt cost rate of 5.31%

The derivation of my 8.88% cost of equity recommendation is summarized on my Schedule ALR 2 and based on a Discounted Cash Flow ("DCF") result of between 8.87% and 8.90%. I used a non-constant DCF Method as a check. Company witness, Mr. Paul R. Moul, states that his analyses indicate that the Company's Cost of Equity should be set at 10.95%, including 25 basis points for recognition of the exemplary performance of the Company's management, and concludes that an ROE of 10.95% for CPA is well within the range of the market based measures[1]. He arrived at his cost of equity recommendation by using the following four costs of equity models: Discounted Cash Flow ("DCF") Model, Risk Premium approach, Capital Asset Pricing Model ("CAPM Analysis") and the Comparable Earnings approach.

Mr. Moul's methods have many limitations which I highlight in my testimony evaluation section. His recommendation includes a double charge to consumers by adding 0.50% to account for "... the lower credit quality of CPA's parent company"[2] while asking consumers to pay for expensive equity (1,402 basis points more than

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[1] Mr. Moul's Direct Testimony, page 6, lines 5-6

[2] Ibid. Page 18, line 18

NiSource[3]) of a capital structure that is much lower risk[4] than the capital structure used by NiSource.

III CAPITAL STRUCTURE, COST OF DEBT AND OVERALL RATE OF RETURN

Q. WHAT IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. The Company is requesting a fully forecasted rate year capital structure consisting of 42.65% long-term debt, 5.14% short-term debt and 52.21% common equity.[5]

Q: IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE APPROPRIATE FOR CPA?

A. No. This capital structure is not appropriate for CPA. First, the requested capital structure does not reflect the capital structure ratios of the Gas Group. As shown on Schedule ALR 6, page 1, the average common equity ratios for the Gas Group is 46.59%. In addition, CPA's requested capital structure has significantly more common equity than CPA's parent, NiSource. As shown on Schedule ALR 6, page 3, the common equity ratio for NiSource is 38.19%. As such, the Company's requested capital structure for CPA is out of line with the capital structure ratios of both the proxy group (Gas Group) that was used to calculate the cost of equity and the capital structure that is used to raise funds for CPA, NiSource.

Q. WHAT CAPITAL STRUCTURE HAVE YOU USED TO COMPUTE THE OVERALL COST OF CAPITAL FOR THE COMPANY?

---

[3] 52.21% (Mr. Moul's recommended common equity ratio) – 38.18% (NiSource's common equity ratio) = 1,402 basis points

[4] Mr. Moul states "...a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk". See pages 15, line 21 and page 16, lines 1-2 of Mr. Moul's Direct Testimony.

[5] Mr. Moul's Direct Testimony page 20, lines 20-22

A. As shown on Schedule ALR 1, page 2, I used the average capital structure ratios of the Gas Group containing 46.75% common equity[6], 10.69 % short-term debt and 42.57% long-term debt to compute the cost of capital for CPA. See Schedule ALR 6, page 1 for the determination of my recommended capital structure. My recommended capital structure is in line with the Commission's stated goal to achieve a fair balance between consumer and stockholder interests[7] because it reflects the capitalizations of the Gas Group and is closer than the Company's requested capital structure to the capitalization that CPA relies upon to raise capital.

Q. HOW DOES THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY AND MR. MOUL'S COST OF EQUITY RECOMEDNATION RESULT IN DOUBLE CHARGING CONSUMERS?

A. Mr. Moul explains this double counting in his direct testimony. Mr. Moul acknowledges that CPA receives its external capital from NiSource[8] and CPA has a greater need for external capital than the Gas Group[9]. He states that a lower common equity ratio implies higher risk[10] (NiSource has a considerably lower common equity ratio (38.19%) than CPA's requested capital structure (52.21%)).

Mr. Moul is recommending double charging CPA's consumers by adding 50 basis points[11] to his recommended ROE to account for the risk related to its low common

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[6] Includes 0.16% of preferred stock
[7] See Pa. P.U.C. v. Emporium Water Company, 208 P.U.R4th 502 (PaPUC 2001).
[8] Mr. Moul's Direct Testimony, page 14, Lines 5-6
[9] Ibid. page 17, lines 20-23
[10] Ibid. page 15. line 21 and page 16, lines 1-2
[11] Ibid. schedule 1, page 2 of 2, "Credit Quality"

equity ratio[12] while charging the consumers for significantly higher common equity than is used to raise funds for CPA. This double counting imposes an unfair cost burden on ratepayers and supports using a hypothetical capital structure in this proceeding.

Q. IF THE COMMISION CHOOSES TO USE THE COMPANY'S REQUESTED CAPITAL STRUCTURE FOR RATE MAKING PURPOSES, WHAT OPTIONS ARE AVAILABE TO BETTER BALANCE THE INTERESTS OF CONSUMERS AND INVESTORS?

A. If the Commission decides that the evidence of this specific case supports the use of the Company's requested capital structure, I recommend using a lower cost of equity (8.34%) to set rates to account for the lower financial risk of a higher common equity ratio.

Q. DID THE COMPANY PROVIDE A RATIONALE FOR ITS CAPITAL STRUCTURE RECOMMENDATION?

A. Yes. Mr. Moul claims the Company's requested capital structure is reasonable by comparing it to the Gas Group's common equity ratios (without short-term debt) over the past five years to the Company's request without-short term debt. He excludes short-term debt from this comparison because of an accounting difference that he does not attempt to reconcile.[13]

As shown in Table 1 below, however, the Company's requested capital structure with short-term debt contains significantly more equity (52.21%) than the CPA's parent

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[12] Mr. Moul recommends charging CPA consumers NiSource's lower credit quality. Ibid. page 18, lines 16-18

[13] "My comparison of these rests on a calculation without short-term debt because the Company uses a twelve-month average for ratesetting purposes, while the GAAP financial reports for the Gas Group use fiscal year-end balances of short-term debt." Mr. Moul's Direct testimony, page 20, lines 8-12

NiSource (38.19%) and the average common equity ratio employed by the Gas Group (46.75%). Hence, CPA's requested capital structure is not reasonable in relation to the Gas Group.

TABLE 1

	Long-Term Debt	Short-Term Debt	Common Equity
CPA's Request (1)	42.65%	5.14%	52.21%
Gas Group (2)	42.57%	10.69%	46.75%*
NiSource (3)	50.42%	11.40%	38.18%

(1) Mr. Moul's Direct Testimony, schedule 1 [1 of 2]
(2) Schedule ALR 6, page 1
(3) Schedule ALR 6, page 3
*Includes 0.16% preferred stock

Q. WHAT DID YOU USE FOR THE COST OF DEBT?

A. I used the Company's proposed cost of long-term debt of 5.31%[14] and its cost of short-term debt of 2.86%[15].

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My overall recommendations for the Company's capital structure and rate of return are provided in Table 2:

---

[14] Mr. Moul's Direct Testimony, page 21 line 17
[15] Ibid. page 22 line 5

TABLE 2

Columbia Gas of Pennsylvania, Inc.
Overall Cost of Capital

	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.57%	5.31%	2.26%
Short-Term Debt	10.69%	2.86%	0.31%
Common Equity	46.75%	8.88%	4.15%
	100.0%		6.72%

Source: Schedule ALR 1

If the Commission decides that the evidence of this specific case supports the use of the Company's requested capital structure, my overall recommendations for the Company's capital structure and rate of return are provided in Table 3:

TABLE 3

Columbia Gas of Pennsylvania, Inc.
Overall Cost of Capital

	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.65%	5.31%	2.26%
Short-Term Debt	5.14%	2.86%	0.15%
Common Equity	52.21%	8.34%	4.35%
	100.0%		6.77%

Source: Schedule ALR 1

IV. COST OF EQUITY IN TODAY'S FINANCIAL MARKET

Q. HOW DOES YOUR COST OF EQUITY RECOMMENDATION RELATE TO THE CURRENT FINANCIAL MARKET?

A. The current capital markets indicate that an 8.88% return on equity for investing in a regulated utility is conservative and arguably high. Equity investors are paying a higher price for earnings than the historical average, and they expect low volatility (low volatility means low risk) which indicates a lower cost of equity than the historical average.

Market data in the following three areas shows that stock markets are expensive (as indicated by price-to-earnings ratio), volatility expectations are low, interest rates remain low by historical standards, and utility stocks remain strong by historical standards as measured by the price-to-earnings ratio, historical and forecasted.

1. **STOCKS ARE EXPENSIVE.** As the S&P 500, Dow Jones Industrial Average and other stock indices make new highs, investors are paying more for the same earnings, including for utility stocks, than average indicating that the cost of equity is lower than average.
2. **VOLATILITY**. The standard deviation in returns is a proxy for risk in portfolio theory. As indicated by the VIX Index,[16] otherwise known as the "Fear Index", investors expect stock price volatility to be considerably lower than average.
3. **INTEREST RATES.** Long-term U.S. Treasury yields are near historic lows (See Chart 5 in "Interest Rates" section of by testimony blow) and Federal Reserve

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[16] The VIX is a measure of the implied volatility of S&P 500 index options representing the market's expectation of stock market volatility over the next 30 day period. It is quoted in percentage points and then annualized. For a more detailed explanation, please see the next page of my testimony.

Chair Janet Yellen said on May 22, 2015 that when the Fed starts to raise interest rates she said "the pace of normalization will be gradual" and objectives will be met by "proceeding cautiously".[17] Future market data indicate that investors believe Ms. Yellen will keep to her word.[18]

I will discuss each of these three areas in more detail later in my testimony. In addition, I will show how allowed returns have trended over time in relation to market data.

Q. HOW DOES YOUR SUMMARY OF THE CURRENT FINANCIAL MARKET RELATE TO YOUR APPROACH TO CALCULATING CPA'S COST OF EQUITY?

A. My role is to determine a return on equity ("ROE") consistent with observable market data. Because the cost of equity is not a published figure like a bond yield, some interpretation is required to determine what the appropriate market based ROE is. It behooves us to respect and recognize the unpredictability of what market prices will be in the future and to use the information in current market prices as our best guide to the cost of equity. Interpretations, opinions and forecasts must never substitute market data.

Q. ARE YOU AWARE OF STUDIES THAT HAVE SHOWN THE CHALLENGES OF FORECASTING FINANCIAL MARKETS?

A. Yes. A Duke University study demonstrated U.S. financial executives were over confident in their ability to predict financial markets. The Chief Financial Officers

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[17] http://www.federalreserve.gov/newsevents/speech/yellen20150522a.htm

[18] "Fed Hones Tricky Message as It Nears Boosting Rates, June 14, 2015

"(CFOs") in the study estimated the returns of Standard and Poor's Index over the following year. The 80% confidence interval provided by the CFOs contained only 33% of the realized returns.[19] The correlation between their estimates and true value was slightly less than zero.

An additional study conducted by McKinsey and Company to determine the accuracy of analysts' earnings forecasts found they were overly optimistic, slow to revise their forecasts and prone to making increasingly inaccurate forecasts during economic downturns. And as indicated by P/E ratios investors' expectations were more conservative.[20]

STOCKS ARE EXPENSIVE

Q. WHAT, IF ANYTHING, DOES THE STOCK MARKET DATA INDICATE WITH REGARD TO THE COST OF EQUITY?

A. A rise in stock prices to all-time highs does not necessarily indicate a decrease in the cost of equity, as expectations regarding earnings could be increasing at a faster rate. However, at the time of filing this testimony there is evidence to suggest that as investors are bidding up stock prices, they are in turn, paying an increased amount for the same earnings.

Q. WHAT EVIDENCE DO YOU HAVE THAT SUPPORTS THAT STOCKS ARE EXPENSIVE?

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[19] Itzhak Ben-David, John R. Graham, Campbell R. Harvey, *Managerial Miscalibration*, July 2010.

[20] Marc H. Goedhart, Rishi Raj and Abhishek Saxena, *Equity Analysts: Still too bullish*, Spring 2010.

A. A common way to measure if stocks are expensive is to look at how much investors are willing to pay for earnings. As shown below, the price-to-earnings ratio and the Shiller ratio for the S&P 500 are high by historical measures and have been increasing lately.

Q. PLEASE EXPLAIN WHAT THE SHILLER RATIO IS.

A. The Shiller ratio is the Price-to-earnings ratio based on average inflation-adjusted earnings from the previous 10 years. The Shiller ratio is known as the cyclically adjusted price to earnings ratio. A recent Wall Street Journal article stated the Shiller ratio is "one of the most widely followed ways of measuring stock valuations."[21]

Q. WHAT ARE THE PRICE-TO-EARNINGS RATIOS INDICATING FOR THE BROADER MARKET?

A. The current Price-to-earnings ratio of the S&P 500 is 20.67 and the Shiller Ratio is 26.63. The long-term average since 1881 is 16.6 (See Chart 1 below) indicating that stocks are expensive, investors are willing to pay more for the same earnings and thus the cost of equity is lower than average.

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[21] "Stock Prices: Is 'Quite High' Too High?, Wall Street Journal, May 15, 2015

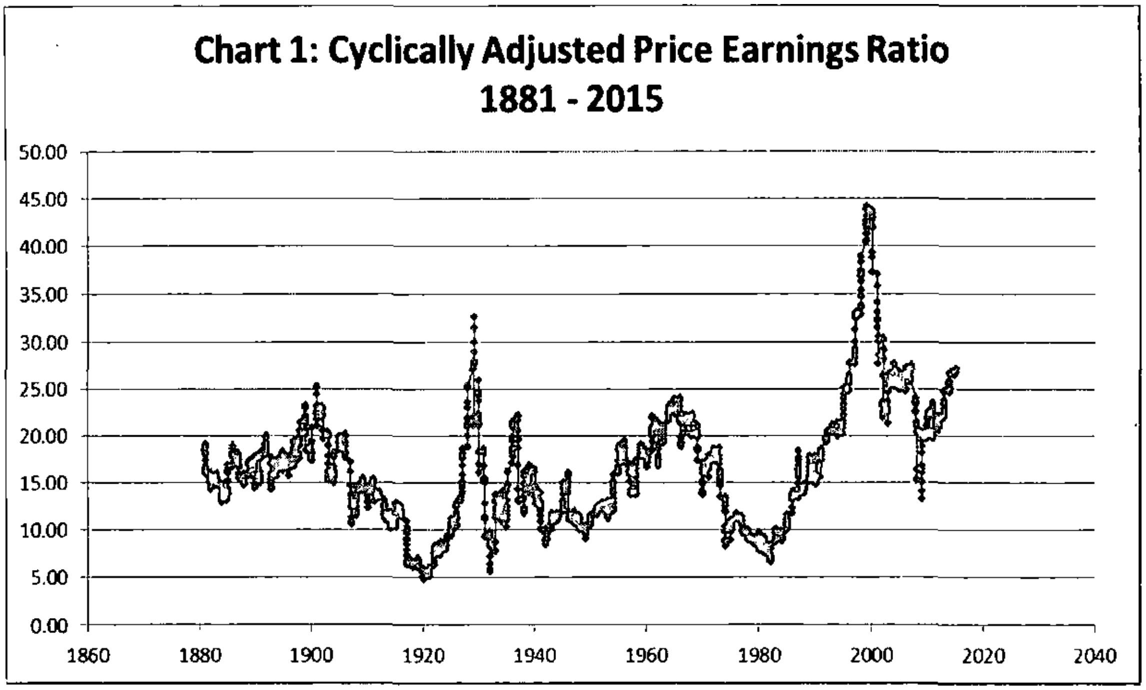
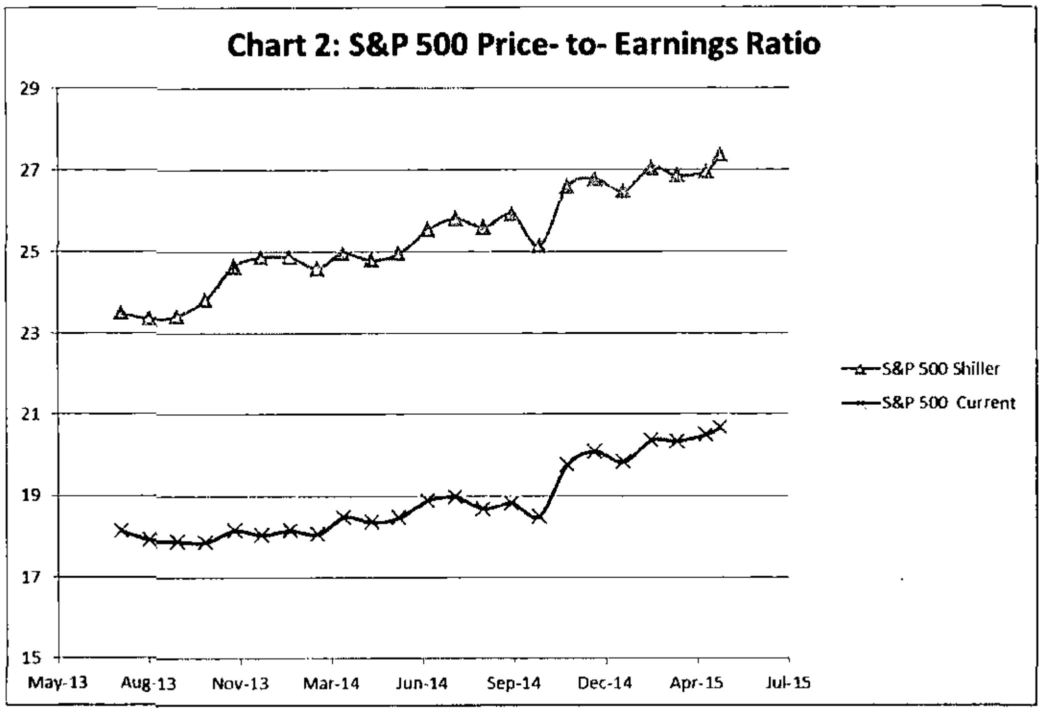


Chart 1: Cyclically Adjusted Price Earnings Ratio 1881 - 2015

As shown in Chart 2 below, the price-to-earnings ratios (as measured by the Shiller-ratio and the current price-to-earnings ratio) has been increasing as major stock market indices including the S&P 500 and Dow Jones Industrial Average have been reaching new highs in recent years.



Q. WHAT IS THE MARKET DATA INDICATING REGARDING HOW EXPENSIVE UTILTY STOCKS ARE?

A. Chart 3 below shows the relative performance of investing the same dollar amount ($9,000)[22] in the Gas Group (Proxy Group Mr. Moul and I used to calculate our cost of equity recommendations), S&P 500 and the Dow Jones Utility Average.

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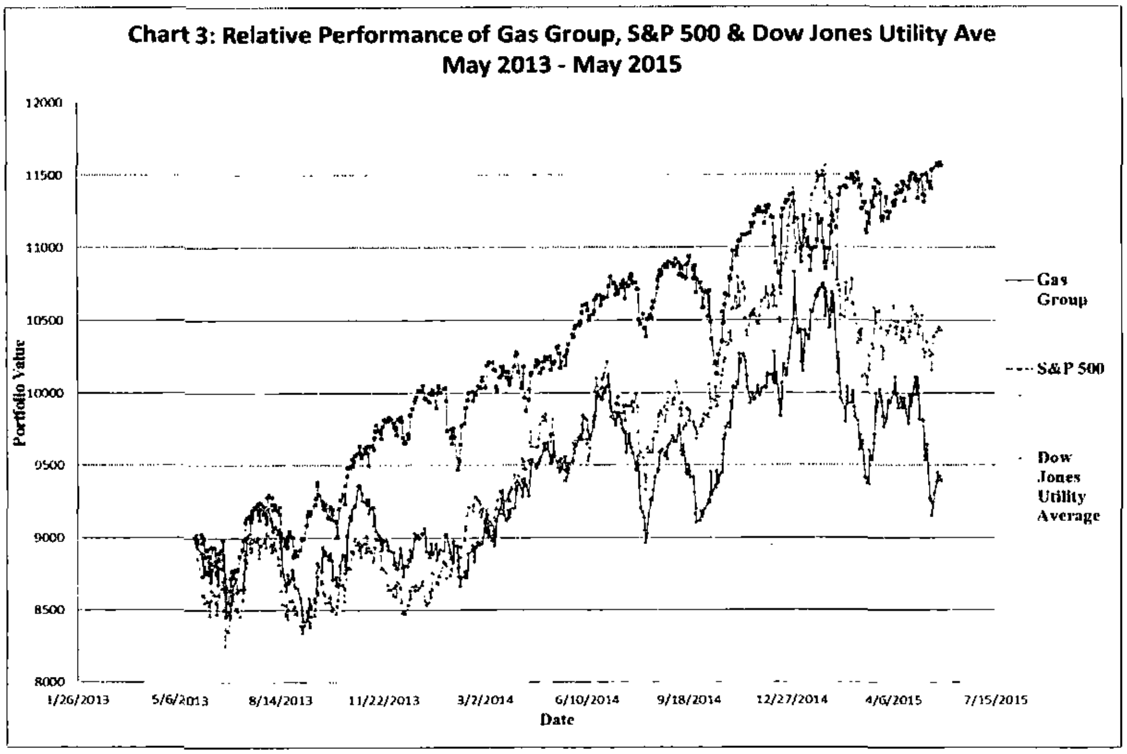
[22] I arbitrarily assigned a $1,000 investment in each of the 9 companies in the Gas Group and thus a total of $9,000 for the S&P 500 and Dow Jones Utility Average for consistency. The relative performance shown in chart 4 would not be impacted by the size of the investment.



The price-to-earnings ratio of utility stocks remain high by historical measures. The forward price-to-earnings ratio for utilities stock is 16.5 and has averaged 14.1 over the past 15 years,[23] and as shown in Chart 4 below, the cyclically adjusted price-to-earnings ratio has increased over the past couple years.

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[23] Guide to the Markets, U.S. 2Q 2015, J.P. Morgan Asset Management

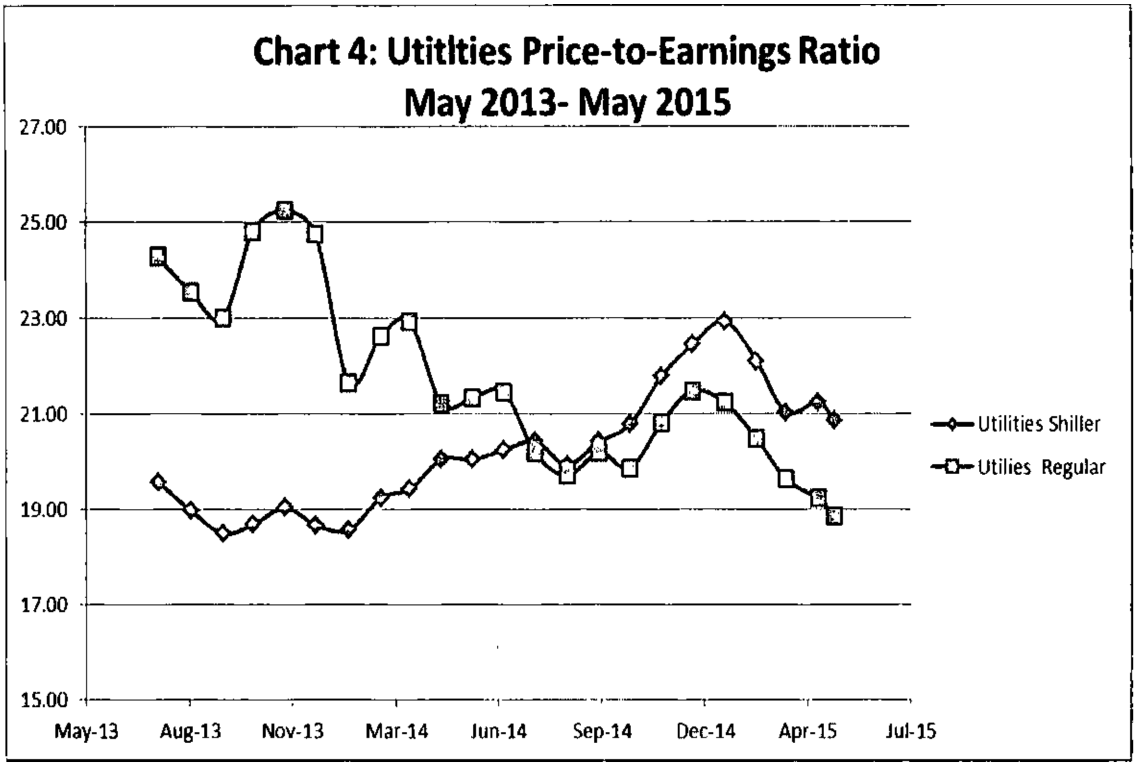


Chart 4 also indicates that investors are paying a higher cyclically adjusted price-to-earnings ratio (Shiller ratio) than two years ago (May 2013) and much of last year, indicating that the cost of equity for utility companies has decreased since the Pennsylvania Commission allowed an ROE under 10% in the Columbia Water case in January 2014.

VOLATILITY IS DOWN

Q. WHAT IS YOUR BASIS FOR CLAIMING THAT INVESTORS VIEW THE MARKETS AS LESS RISKY?

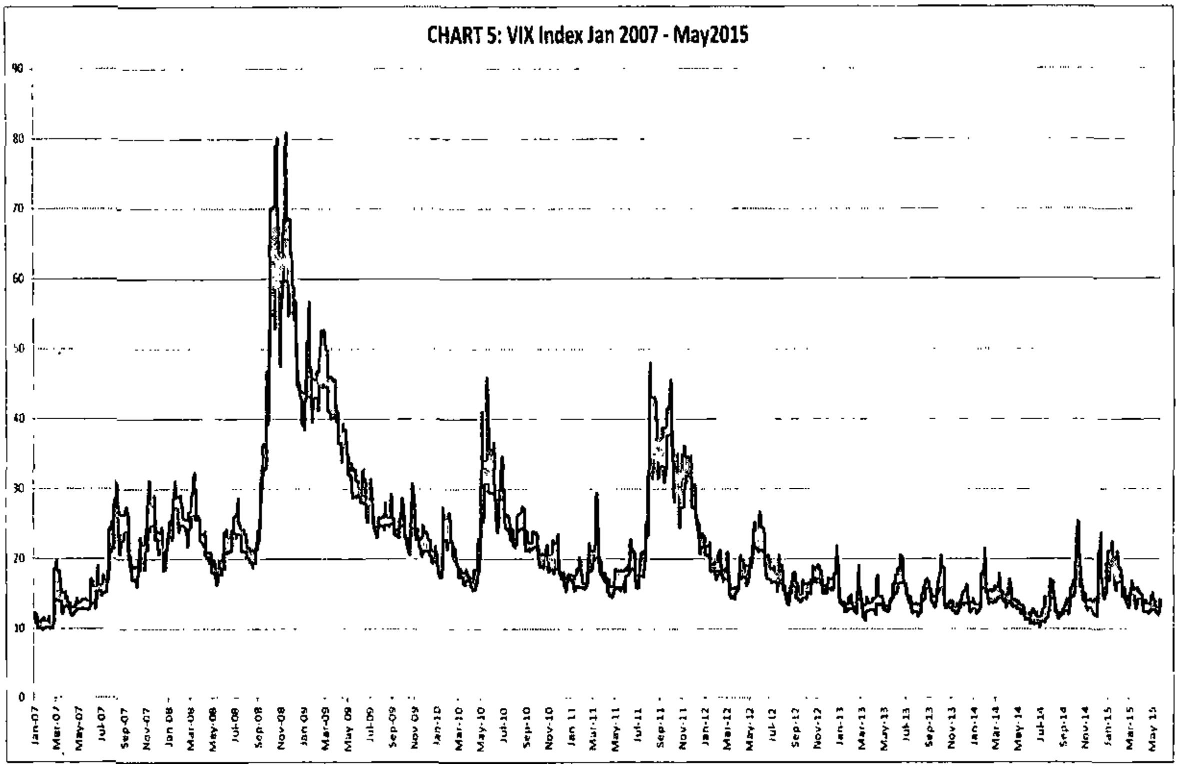
A. The VIX index is a market indicator that allows us to see what investors expect volatility to be in the future. Volatility, uncertainty and risk are synonymous. Therefore, the VIX index can be a valuable tool to determine investors' assessment of the riskiness of financial markets. This is a more direct route than trying to monitor world events, expert forecasts and surveys. This direct route has not only proven to be more accurate than forecasts and interpretations, but is also aligned with the principle that the cost of capital is a market-based concept. The market index is indicating that investors' perception of future volatility has decreased significantly. This market index is called the VIX Index and was initiated in 1993.

Q. PLEASE EXPLAIN FURTHER WHAT THE VIX INDEX IS AND HOW IT IS ESTABLISHED.

A. The Chicago Board Options Exchange ("CBOE") Market Volatility Index ("VIX") is based on options on the S&P 500 Index and reflects the market consensus expected volatility in the S&P 500 over the next 30 days on an annual basis. It is sometimes known as the "fear index."

Q. WHAT IS THE MARKET PRICE OF THE VIX CURRENTLY AND HOW DOES THIS COMPARE TO PRICES DURING THE GREAT RECESSION?

A. As of May 31, 2015, the VIX Index was trading at 13.84, indicating that investors expect an annualized change of 13.84% over the next 30 days. At the height of the financial crisis in 2008, the VIX Index was trading at over 80, indicating that investors expected an annualized change of over 80% over the same 30 day period. As can readily be seen in the chart below, the VIX Index is significantly lower than it was during the financial crisis and is nearing pre-crisis levels.



Q. IS THERE MARKET DATA AVAILABLE THAT SHOWS WHAT THE MARKET EXPECTATION IS FOR VOLATILITY OVER A LONGER PERIOD THAN 30 DAYS?

A. Yes. A volatility index, under the ticker symbol "VXV," is based on the same methodology as the VIX but structured to measure the markets expectation of 3-month volatility.

Q. IS THE VXV ALSO INDICATING THAT INVESTORS' EXPECTATIONS OF VOLATILITY ARE DOWN?

A. Yes. As of May 31, 2015, the VXV was trading at 15.38 indicating investors expect an annualized change of 15.38% over the next 90 days on an annual basis. This is down from a high of over 60 during the financial crisis in 2008 and near historic lows since the index was initiated.

Q. WHAT, IF ANYTHING, DOES A LOW VIX INDEX INDICATE WITH REGARD TO THE COST OF EQUITY?

A. Studies have shown that there is a positive correlation between the equity risk premium and the expected volatility as indicated by the VIX index.[24] As the VIX decreases, investors view the market as less risky and therefore generally demand a lower premium to purchase equities, over U.S. Treasuries or other lower risk investment, indicating a lower cost of equity.

INTEREST RATES

Q. DO INVESTORS EXPECT U.S. GOVERNMENT BOND YIELDS TO STAY AT THESE LOW LEVELS?

A. Yes. The yields on short term U.S. Treasuries are still being kept at near zero by the United States Government and yields on long-term U.S. government bonds have been decreasing in recent months. The market data are consistent with recent comments made by Federal Reserve Chairman Janet Yellen who stated at a presentation on May 22, 2015 regarding raising interest rates, "After we begin raising the federal funds rate, I anticipate that the pace of normalization is likely to be gradual."[25] Fed-funds futures are indicating that investors believe there is 31% chance that the Federal Reserve will increase rates in

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[24] Aswath Damodaran, *Equity Risk Premiums (ERP): Determinates, Estimation and Implications* – The 2014 Edition (paper updated, March 2015). Pages 98-101.

[25] http://www.federalreserve.gov/newsevents/speech/yellen20150522a.htm

September 2015 [26] and the market expects rates to be increased more gradually than published Federal Reserve projections.[27]

Q. WHAT DO LOW U.S. TREASURY YIELDS MEAN FOR THE COST OF EQUITY?

A. Historical market data indicate that a low interest rate environment, like we have now, indicates a low cost of equity. Chart 6 below shows that as interest rates decrease the yield credit spread between Baa rated corporate bonds and U.S Treasuries, which is a proxy for the cost of equity, has remained relativity stable (except for the great recession). This chart indicates that the cost of equity decreases as interest rates decrease because the extra yield investors demand to purchase Baa, Corporate bonds, and equities, is over a lower "risk free" rate of return.

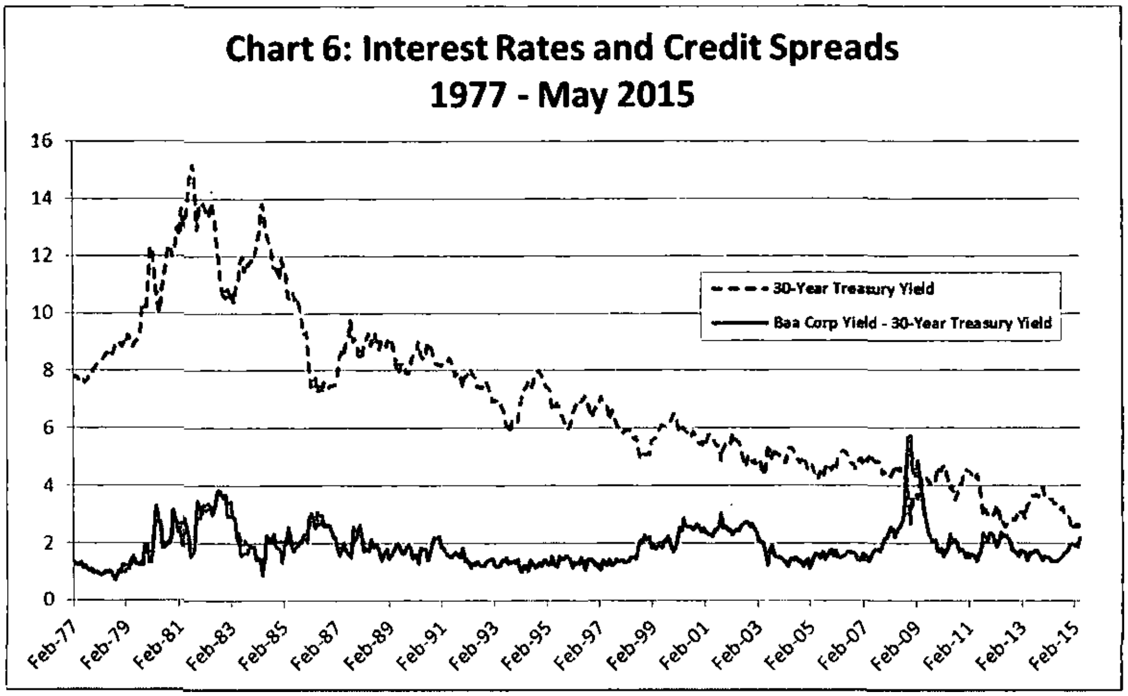

Chart 6: Interest Rates and Credit Spreads
1977 - May 2015

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[26] "U.S Stocks Ease on Rate Worries" Wall Street Journal June 5, 2015.

[27] "Fed Hones Tricky Message as It Nears Boosting Rates, June 14, 2015

Q. CAN YOU PLEASE PUT THE CURRENT INTEREST RATE ON 30-YEAR U.S. TREASURY BONDS INTO HISTORICAL PERSPECTIVE?

A. The following graph shows that, as of May 2015 the yield on 30-year Treasury bonds is low by historical standards. The rate has been in a long-term downward trend since the very early 1980's when the annual yield peaked just below 14%. As shown in the chart below, yields on 30-year U.S. Treasury Bonds have increased from about 2.9% in April 2013 to nearly 4.0% by the end of 2013 and has fallen to under 2.8% in May 2015.

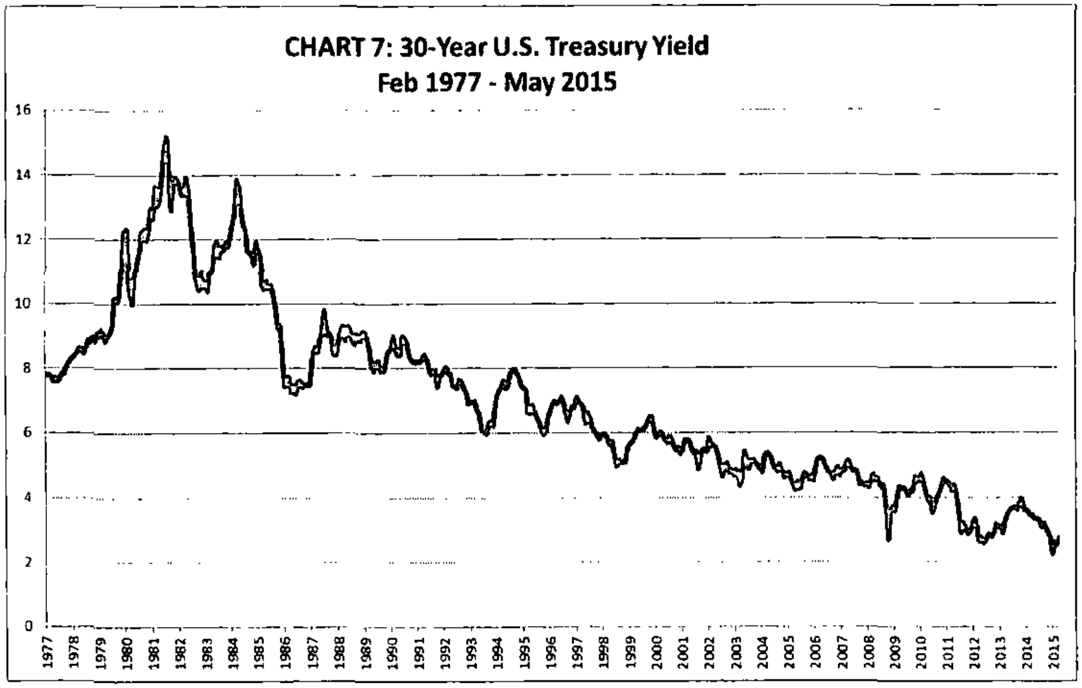
CHART 7: 30-Year U.S. Treasury Yield
Feb 1977 - May 2015

Q. DO YOU KNOW WHAT INTEREST RATES WILL BE IN THE FUTURE?

A. No. Although Janet Yellen has indicated that it may be appropriate to start raising the federal funds rate this year, she emphasized the uncertainty surrounding forecasting the economy and the financial markets in a recent speech in Providence Rhode Island, stating:

> I am describing the outlook that I see as most likely, but based on many years of making economic projections, I can assure you that any specific projections I write down will turn out to be wrong, perhaps markedly so.

Many economists and forecasters will continue to be quoted in the press even regarding developments that are unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[28]

Daniel Kanheman found that the trading industry is based on an "allusion of skill." His research showed no correlation between the performances of advisors from year to year indicating that the results resembled what you would expect from a "dice rolling contest, not a game of skill," stating:

> The evidence from more than fifty years of research is conclusive: for a large majority of fund managers, the selection of stocks is more like rolling dice than like playing poker.[29]

CPA's cost of capital is based on the current capital markets and we should not fall into the trap of giving weight to forecast or expert opinion. Such forecasts have been found to be inaccurate. In addition, the utilization of these forecasts violate rate making principles; namely that the cost of equity should be market based.

Q. HAVE UTILITY COMMISSIONS FOLLOWED THE DOWNWARD TREND IN INTEREST RATES WITH AN ASSOCIATED DOWNWARD TREND IN AUTHORIZED RETURNS?

A. Yes, but considering the magnitude of the decrease in bond yields, in far from direct proportion. The following graph shows the relationship between the average allowed

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[28] Daniel Kahneman, *Thinking Fast and Slow* (New York: Farrar, Straus and Gigoux, 2011): 212.

[29] Ibid: 215

return on common equity awarded to regulated electric utility companies and the interest rate on long-term U. S. Treasury bonds. Even with the increase in interest rates in 2013, the spread between average allowed returns in ten year US Treasury Yields is 764 basis points.[30]

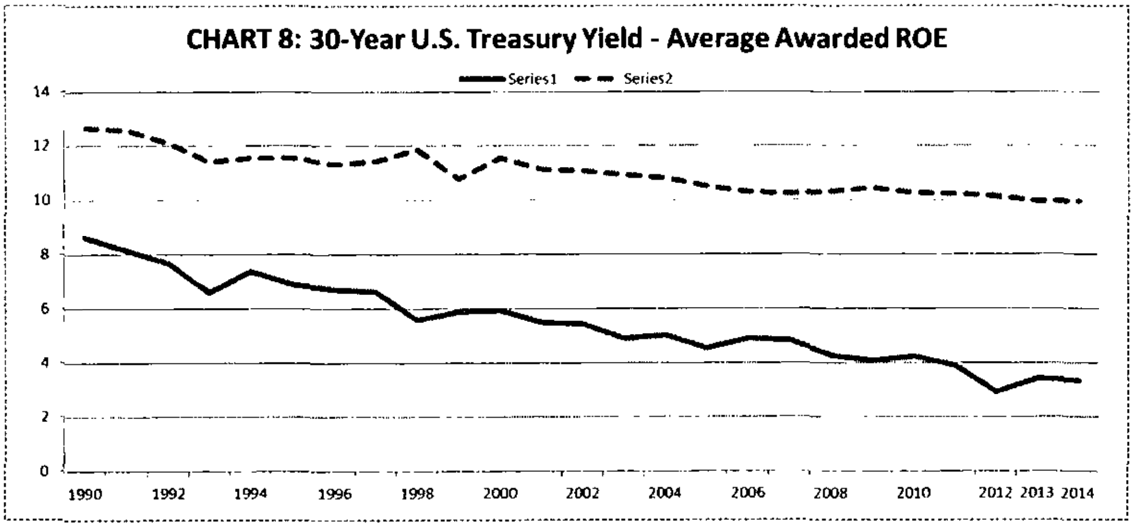

CHART 8: 30-Year U.S. Treasury Yield - Average Awarded ROE

Q. HAVE SOME PUBLIC UTILITY COMMISSIONS ISSUED DETERMINATIONS WHERE A COMPANY'S RETURN ON EQUITY IS LESS THAN THE AVERAGE AWARD OF ABOUT 10%?

A. Yes. Because we have been speaking about an average as well as an average that is declining, a number of Commissions have obviously made determinations of companies' cost of equity at below 10%, including the Pennsylvania Commission.

Chart 8 above demonstrates that allowed returns trended in the same general direction as long-term interest rates until about 2006, but once the average allowed return reached about 10%, the average stopped tracking the 30-year U.S. Treasury Yields. Even

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[30] 9.99% Average Allowed Electric ROE in 2013 – 2.35% Average Yield on 10 Year U.S. Treasury bond in 2013.

though interest rates continued to drop since 2005, average allowed returns are just starting to drop below10%. The Ibbotson SBBI 2013 Classic Yearbook states:

> The average target return on equity that regulators granted utilities dropped to 9.9% during the second quarter, its lowest level in at least 20 years. Even *with this drop, the spread between these allowed returns and* the 10-year U.S. Treasury yield remains at all-time highs near 800 basis points.[31] For the first quarter of 2015 the average allowed return for gas distribution companies was 9.47%.[32]

Q. FROM YOUR EXPERIENCE IN UTILITY REGULATION, WHY DO YOU THINK THE AVERAGE ALLOWED RETURN HAS JUST RECENTLY DROPPED BELOW 10%?

A. While no reasons are provided to explain the significant lag between the actual decrease in the cost of equity in the markets and the average return to regulated utilities allowed by public utility commissions, as company witnesses often contend, there is a persistent disbelief that interest rates could stay as low as they have for as long as they have. The end result is that, on average, allowed returns have been artificially kept higher than necessary. As discussed earlier, although interest rates have increased in 2013, spreads between allowed returns and interest rates are still near historical highs. As quoted earlier, the Fed Chairman indicated "the pace of normalization is likely to be gradual" and it is possible the low interest rate environment will remain for some time.

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[31] Ibbotson SBBI 2013 Classic Yearbook, page 28.

[32] Mr. Moul's response to Question No. OCA 6-003

V. COST OF EQUITY CALCULATION

a. DISCOUNTED CASH FLOW

Q. WHICH COMPANIES DID YOU INCLUDE IN YOUR COMPARABLE GROUP OF UTILITY COMPANIES TO DETERMINE YOUR COST OF EQUITY RECOMMENDATION?

A. I included the nine U.S. gas utility companies, referred to as the Gas Group, used by Company Witness Mr. Moul as shown on schedule 3 page 2 of 2 of his direct testimony.

Q. HOW DID YOU ARRIVE AT YOUR COST OF EQUITY RECOMMENDATIONS?

A. I used the constant growth form of the Discounted Cash Flow ("DCF") method that determines growth based on the sustainable retention growth procedure. I used a non-constant DCF method as a check. Later in my testimony I explain the theory behind the DCF method and why it is the best way to determine investor expected returns.

Q. WHAT IS THE DISCOUNTED CASH FLOW METHOD?

A. The Discounted Cash Flow, or DCF method is an approach to determining the cost of equity which recognizes that investors purchase common stock to receive future cash payments. These payments come from: (a) current and future dividends; and (b) proceeds from selling stock. A rational investor will buy stock to receive dividends and to ultimately sell the stock to another investor at a gain. The price the new owner is willing to pay for stock is related to the future flow of dividends and the future expected selling price. The value of the stock is the discounted value of all future dividends until the stock is sold plus the value of proceeds from the sale of the stock. For example, if the cost of equity is 9% and the dividend is $1 per share, then the $1 dividend paid out next year is today worth $1/[$1+.09] which equals $0.92 reflecting the discounted present value.

Q. HAVE INVESTORS ALWAYS USED THE DCF METHOD?

A. While investors who buy stock have always done so for future cash flow, the DCF approach first appeared in the 1937 Harvard Ph.D. thesis of John Burr Williams titled *The Theory of Investment Value*. "Williams' model for valuing a security calls for the investor to make a long-run projection of a company's future dividend payments ..."[33] The Williams DCF model separately discounts each and every future expected cash flow. Its accuracy is therefore unaffected by non-constant growth rates. Myron Gordon and Eli Shapiro who helped to make this method widely used, referred to Williams' work in their paper published in 1956 "Equipment Analysis: The Required Rate of Profit."

Q. HOW DID INVESTORS EVALUATE STOCKS BEFORE WILLIAMS INTRODUCED THE DCF METHOD?

A. Before the DCF method, investors used methods such as P/E ratios (or its reciprocal the E/P ratio, or earnings yield), or dividend yield (D/P). While these methods are still used today, knowledgeable investors are aware that they are very incomplete and provide only rough guidelines to investment value.

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[33] P. BERNSTEIN, *Capital Ideas: The Improbable Origins of Modern Wall Street* (The Free Press, © 1992).

The appropriate P/E ratio for a company with high growth prospects can be much higher than for a company with meager growth opportunities. Therefore, P/E ratios alone do not predict the total return an investor expects to earn from purchasing stock in that company. Similarly, the D/P analysis cannot distinguish important differences between companies with similar D/P ratios but vastly different prospects for future dividend payments. By concentrating on both current dividends and future expected dividend payments, the Williams or non-constant DCF model filled in the major gaps in the P/E ratio and D/P methods. I will discuss the use of the non-constant growth form of the DCF model in detail later in my testimony.[34]

b. CONSTANT GROWTH FORM OF THE DCF MODEL

Q. YOU STATE YOU USED THE CONSTANT GROWTH FORM OF THE DCF MODEL. WHAT IS THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. The constant growth form of the DCF model is a form of the DCF method that can be used in determining the cost of equity when investors can reasonably expect that growth of retained earnings and dividends will be constant.

Q. WHAT ARE RETAINED EARNINGS?

A. Retained earnings are funds that a company keeps to grow and invest in business or pay off debt.

Q. WHY DO INVESTORS LOOK AT THE GROWTH OF RETAINED EARNINGS?

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[34] I use the result of my non-constant growth method as a check on my constant growth DCF result. See Schedule ALR 2 for the results of both of these methods.

A. Retained earnings show investors whether the company is growing which, in turn, is a measure of the future indicator of the value of a company's stock.

Q. DESCRIBE HOW THE CONSTANT GROWTH MODEL WORKS.

A. The constant growth model is described by this equation k= D/P + g, where:[35]

k= cost of equity;
D=Dividend rate; and
P=Market price of stock.

In the above equation:

g=the growth rate, where g= br + sv;
b=the earnings retention rate;
r=rate of return on common equity investment;
v=the fraction of funds raised by the sale of stock that increases the book value of the existing shareholders' common equity; and
s=the rate of continuous new stock financing.

The constant growth model is therefore correctly recognized to be:

$k=D/P + (br + sv)$

Q. WHAT OTHER FACTORS IMPACT THE USE OF THE CONSTANT GROWTH FORM OF THE DCF MODEL

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[35] M. GORDON, *Cost of Capital to a Public Utility*, at 32-33 (MSU Public Utility Studies 1974).

A. Sufficient care must be taken to be sure that the growth rate "g" is representative of the constant sustainable growth required for the answer from the constant growth form of the DCF model to be meaningful. In order to obtain a creditable constant growth DCF result the mathematical relationship between earnings, dividends, book value and stock price must be respected.

For example, suppose one is faced with a situation where Value Line forecasts are being used as a source for inputs and Value Line projects different growth rates for earnings per share and dividends per share. Under such conditions, the earnings per share growth rate does not provide a reasonable proxy for earnings per share growth, and dividends per share and stock price growth as well. Consider the following:

1. It is the lower dividend growth rate that makes it possible for more earnings to be retained, which in turn makes the earnings per share growth rate higher than it would be if dividends had in fact been modeled by Value Line to keep pace with earnings per share growth.

2. The lower dividend growth rate than both the earnings per share growth rate and the stock price growth rate means that the dividend yield will be going down. Yet, the constant growth form of the DCF model has no mechanism to account for the lower dividend yield investors would get if the Value Line projections were correct.

Using an earnings per share growth rate in the constant growth form of the DCF model will therefore result in an overstatement of the cost of equity whenever the earnings per share growth rate that has been modeled by the analyst was derived along with an expectation of a lower dividend growth rate. This is because under these conditions, the dividend yield portion of the constant growth form of the equation will be overstated.

The basic difference between the use of an analysts earnings per share growth rate in the constant growth DCF formula and using the "br" (b=the earnings retention rate X the rate of return on common equity investment) approach is that the "br" form if properly applied eliminates the mathematical error caused by an inconsistency between the expectations for earnings per share growth and dividends per share growth. Because of the elimination of mathematical problems in the constant growth form due to inconsistencies between the earnings per share and dividends per share growth rate, the accuracy of the results of a properly applied "br" approach will be superior and often materially superior to the answer obtained from other approaches to the constant growth form of the DCF model. This is not to say that even a properly applied "br" approach will be perfect. The self-correcting nature of a properly applied "br" to forecasted differences in earnings per share and dividends per share growth rates is a big help in mitigating the resultant computational error but should not be viewed as the perfect way to quantify the impact of expected non-constant growth rates.

As I will discuss later, Mr. Moul fails to use a growth rate "g" that is representative of the constant sustainable growth required for the answer from the constant growth form of the DCF model to be meaningful. However, this is one of the rare times when equity analyst's 5 year EPS growth forecast is in line with appropriately calculated growth rate.

Q. HOW CAN INACCURACIES IN THE DCF RESULT, CAUSED BY FORECASTED DIFFERENCES BETWEEN THE EPS GROWTH RATE AND THE DIVIDENDS PER SHARE GROWTH RATE, BE ELIMINATED?

A. One way to correct such a problem is to reject the constant growth DCF model in favor of the non-constant growth DCF model. The non-constant growth DCF model separately discounts the anticipated cash flow in each subsequent year so that changes in the dividend payout ratio and anticipated changes in the earned return on book equity can both be quantified in a way that retains mathematical accuracy. The simplest way to avoid adding this extra complexity in a way that, especially for regulated public utilities, will generally retain mostly all of the accuracy obtainable from the non-constant growth model is to quantify growth by using "br" + "sv," in which:

1. The retention rate "b" is the earnings retention ratio computed to be consistent with the dividend rate used in the D/P term of the constant growth DCF formula, and

2. It is recognized that at any point in time, the price investors are willing to pay for a company's stock relates to what earnings are expected at that time. The only relevant estimate of the return on equity "r" that should be used in the DCF formula is the one that investors expect to be on average earned at the time of the quantification of the stock price used in the DCF formula.

By following these two relatively simple guidelines, the accuracy of the DCF method will in most cases be highly dependent on the estimate for the value of the future expected return on book equity, "r."

Q. ARE YOU AWARE OF CLAIMS THAT A PROBLEM WITH THE "BR" APPROACH TO THE CONSTANT GROWTH DCF MODEL IS THAT IT RELIES ON THE VALUE OF THE FUTURE EXPECTED RETURN ON BOOK EQUITY "r" TO ESTIMATE WHAT THE EARNED RETURN ON EQUITY SHOULD BE?

A. Yes. There are multiple reasons why this concern is unfounded:

1. The constant growth form of the equation using br is:

$$k= D/P + (br + sv).$$

In this equation, k is the variable for the cost of equity, and r is the future expected return on equity. The cost of equity, "k," is not the same variable as the future expected earned return on equity, "r." In fact, there often is a large difference between the two.

2. The correct value to use for "r" is the return on book equity expected by investors as of the time the stock price and dividend data is used to quantify the D/P term in the equation. Therefore, even if future events occur that may change what investors expect for "r", the computation of the cost of equity "k" remains correct as of the time the computation was made.

3. The ability of a commission decision to influence future cash flow expectations is not unique to the retention growth approach to the DCF method. The five-year analysts' earnings per share growth rate is a computation that is directly influenced by what earnings per share will be in five years. A change in

what analysts expect will be the allowed return on equity for earnings generated five years from now will change not only the expected earnings per share five years from now, but will also change the five year earnings per share growth rate.

Q. CAN CHANGES IN THE OVERALL EARNED RETURN IMPACT GROWTH ABOVE AND BEYOND WHATEVER GROWTH RESULTS FROM EARNINGS RETENTION?

A. Yes, but one-time changes in EPS caused by a perceived change in the future expected earned returns are unsustainable. The new perceived earned return on book equity should be part of the computation, but the one-time growth spurt to get there is no more indicative of the sustainable growth required in the constant growth DCF formula than the temporary negative growth that occurs when a company has a bad year.

Q. HOW HAVE YOU IMPLEMENTED THE CONSTANT GROWTH FORM OF THE DCF MODEL IN THIS CASE?

A. I have applied the constant growth form of the DCF model by staying true to the mathematically derived "k=D/P + (br + sv)" form of the DCF model. I have also taken care to fully allocate all future expected earnings to either future cash flow in the form of dividends ("D") or to retained earnings (the retention rate, "b"). This extra accuracy is obtained only when the retention rate "b" is derived from the values used for "D" and "r" rather than independently.

This DCF method was applied to a proxy group (Gas Group) of 9 U.S. gas utilities used by Company witness Mr. Moul.

Q. PLEASE EXPLAIN HOW YOU OBTAINED THE VALUES TO INPUT INTO THE CONSTANT GROWTH FORM OF THE DCF METHOD.

A. The DCF model generally calls for the use of the dividend expected over the next year. A reasonable way to estimate next year's dividend rate is to increase the quarterly dividend rate by ½ of the current actual quarterly dividend rate. This is a good approximation of the rate that would be obtained if the full prior year's dividend were escalated by *the entire growth rate.*[36]

I obtained the stock price "P" used in my DCF analysis from the closing prices of the stocks on May 31, 2015. I also obtained an average stock price for the 12 months ending May 31, 2015 by averaging the high and low stock prices for the year.

I based the value of the future expected return on equity, "r", on the average return on book equity expected by Value Line. I also made a computation that was based on a review of both the earned return on equity consistent with analysts' consensus earnings growth rate expectations and on the actual earned returns on equity. For a stable industry such as utility companies, investors will look at typical actual earned returns on

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[36] For example, assume a company paid a dividend of $0.50 in the first quarter a year ago, and has a dividend growth rate of 4 % per year. This dividend growth rate equals (1.04)^4-1=0.00985 % per quarter. Thus, the dividend is $.5049 in the second quarter, $.5099 in the third quarter, and $0.5149 in the fourth quarter.

If that 4 % per annum growth continues into the following year, then the dividend would be $0.5199 in the 1st quarter, $0.5251 in the 2nd quarter, $0.5303 in the 3rd quarter, and $0.5355 in the 4th quarter. Thus, the total dividends for the following year equal $2.111 (0.5199 + 0.5251 + 0.5303 + 0.5355). I computed the dividend yield by taking the current quarter (the $0.5149 in the 4th quarter in this example), and multiplying it by 4 to get an annual rate of $2.06. I then escalated this $2.06 by ½ the 4 % growth rate, which means it is increased by 2 %. $2.06 x 1.02= $2.101, which is within one cent of the $2.111 obtained in the example.[36]

equity as one meaningful input into what can be expected for future earned returns on book equity. See Schedule ALR 4, page 1.

This return on book equity expectation used in the DCF method to compute growth must *not* be confused with the cost of equity. Since the stock prices for the comparative companies are considerably higher than their book value, the return investors expect to receive on their market price investment is considerably less than whatever is the anticipated return on book value. If the market price is low, the cost of equity will be higher than the future expected return on book equity, and if the market price is high, then the return on book equity will be less than the cost of equity.

In addition to growing through the retention of earnings, utility companies also grow by selling new common stock. I quantified this growth caused by the sale of new common stock above book value by multiplying the amount that the actual market-to-book ratio exceeds 1.0 by the compound annual growth rate of stock that Value Line forecasts. The results of that computation are shown on line 4 of Schedules ALR 4, page 1.

Pure financial theory tends to prefer concentrating on the results from the most current price because investors cannot purchase stock at historical prices. Others are concerned about the potential distortion of using just a spot price. I present both so the Commission can use the perspective it feels is most appropriate. As shown on Schedule ALR 2, my DCF method, applied to the Gas Group, the DCF result based on the year-end stock price and the DCF result based on average prices for the year ending May 31, 2015 is 8.87% and as of May 31, 2015 the result is 8.90%. Schedule ALR 4, page 1 shows more of the specifics of how I implemented the constant growth form of the DCF model for the Gas Group.

Q. PLEASE EXPLAIN HOW YOU DETERMINED WHAT VALUE TO USE FOR "R" WHEN COMPUTING GROWTH IN YOUR CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The inputs I considered are shown in Footnote [A] of Schedule ALR 4, page 1. The value of "r" that is appropriate to use in the DCF formula is the value anticipated by investors to be maintained on average in the future. This schedule shows that the average future return on equity forecast by Value Line on average for the Gas Group for 2017-2019/2018-2020 is 10.22%. The same footnote also shows that the future expected return on equity derived from the Zacks consensus forecast is 8.89%, and that the actual returns on equity earned on average by the Gas Group were 9.92% in 2012, 9.02% in 2013 and 9.95% in 2014. Based on the combination of the forecast return on equity derived from the Zacks consensus, the recent historical actual earned returns and Value Line's forecast, I made the DCF growth computation using a 10.50% value of "r".

Q. WHAT COST OF EQUITY IS INDICATED BY THE CONSTANT GROWTH FORM OF THE DCF METHOD THAT YOU RELY ON FOR YOUR RECOMMENDATION?

A. The result of my DCF analysis using the Constant Growth form of the DCF indicates a cost of equity range of between 8.87% and 8.90% for the Gas Group.[37] Since these DCF findings use analysts' forecasts to derive sustainable growth in the Retention Growth

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[37] Schedule ALR 2

DCF method and relies on analysts' forecasts of dividend growth and book value growth in the non-constant form of the DCF method, the results should be considered as conservatively high.

It should be noted that the results I have obtained are not as influenced by over-optimistic analysts' forecasts as would have been the case if I had merely used analysts' five year earnings growth rate forecasts as a proxy for long-term growth. This is because the DCF methods I use compute sustainable growth rates rather than growth rates that exaggerate the growth rate due to end-point distortion.

c. NON-CONSTANT GROWTH FORM OF THE DCF MODEL

Q. WHAT IS THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL?

A. The non-constant growth form of the DCF model is a method that accounts for growth rates that change over time.

Q. EARLIER YOU STATE THAT YOU USED THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL AS A CHECK. PLEASE EXPLAIN HOW YOU DID THAT.

A. The non-constant growth form of the DCF model determines the return on investment expected by investors based on an estimate of each separate annual cash flow the investor expects to receive. For the purpose of this computation, I relied on Value Line's detailed annual forecasts to arrive at the specific non-constant growth expectations that an investor who trusts Value Line would expect. This implementation is shown on schedule ALR 4, page 2. The first cash flow entry is the cash outflow an investor would experience when buying a share of stock at the market price. The subsequent years of cash flow are equal to the dividends per share that Value Line forecasts. For the intermediate years of the forecast period in which Value Line does not provide a specific dividend, the annual dividends were obtained by estimating that dividend growth would persist at a compound annual rate. The cash flow at the end of the forecast period consists of both the last year's dividend forecast by Value Line and the proceeds from the sale of the stock. The stock price used to determine the proceeds from selling the stock was obtained by estimating the stock price would grow at the same rate Value Line forecasts book value to grow.

Q. WHY DID YOU USE BOOK VALUE GROWTH TO PROVIDE THE ESTIMATE OF THE FUTURE STOCK PRICE?

A. For any given earned return on book equity, earnings are directly proportional to the book value. Furthermore, book value growth is the net result after the company produces earnings, pays a dividend and also perhaps either sells new common stock at market price or repurchases its own common stock at market price.

Once these cash flows are entered into an Excel spreadsheet, the compound annual return an investor would achieve as a result of making this investment was obtained by using the Internal Rate of Return (IRR) function built into the spreadsheet. As shown on Schedule ALR 4, page 2 this multi-stage DCF model produced an average indicated cost of equity of 8.95% for the Gas Group.

Q. YOUR NON-CONSTANT GROWTH DCF MODEL USES ANNUAL EXPECTED CASH FLOWS. SINCE DIVIDENDS ARE PAID QUARTERLY RATHER THAN ANNUALLY, HOW DOES THIS SIMPLIFICATION IMPACT YOUR RESULTS?

A. I used the annual model because it is easier to both input the data and for observers to visualize what is happening. By modeling cash flows to be annual rather than when they actually are expected to occur causes a small overstatement of the cost of equity.

Q. WHY IS IT A SMALL OVERSTATEMENT IF YOU HAVE MODELED DIVIDENDS TO BE RECEIVED SOME MONTHS AFTER INVESTORS ACTUALLY EXPECT TO GET THEM?

A. The process of changing from an annual model to a quarterly model would require two changes, not just one. A quarterly model would show dividends being paid sooner and would also show earnings being available sooner. A company that receives their earnings sooner, rather than at the end of the year, has the opportunity to compound them. Since revenues and therefore earnings are essentially received every day, a company that is supposed to earn an annual rate of 9.00% on equity would only have to earn 8.62% if the return were compounded daily.[38] This reduction from 9.00% to 8.62% would then be partially offset by the impact of the quarterly dividend payment to bring the result of switching from the simplifying annual model closer to, but still a bit below, 9.00%.

Q. BY USING CASH FLOW EXPECTATIONS AS THE VALUATION PARAMETER, DOES THE NON-CONSTANT DCF MODEL STILL RELY ON EARNINGS?

A. It relies on an expectation of future cash flows. Future cash flows come from dividends during the time the stock is owned and the proceeds from the sale of the stock once it is

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[38] (1+.0862/365)^365=1.09=9.00 %.

sold. Since earnings impact both dividends and stock price, the non-constant DCF model still relies on earnings

Every dollar of earnings is used for the benefit of stockholders, either in the form of a dividend payment or earnings reinvested for future growth in earnings and/or dividends. Earnings paid out as a dividend have a different value to investors than earnings retained in the business. Recognizing this difference and properly considering it in the quantification process is a major strength of the DCF model, and is why the non-constant DCF model is as I have set forth an improvement over either the P/E ratio or D/P methods.

Q. WHY IS THERE A DIFFERENCE TO INVESTORS IN THE VALUE OF EARNINGS PAID OUT AS A DIVIDEND COMPARED TO THE VALUE OF EARNINGS RETAINED IN THE BUSINESS?

A. The return on earnings retained in the business depends upon the opportunities available to that company. If a regulated utility reinvests earnings in needed used and useful utility assets, then those reinvested earnings earn at whatever return is consistent with the ratemaking procedures allowed and the skill of management.

When an investor receives a dividend, he can either reinvest it in the same or another company or use it for other things, such as paying down debt or paying living expenses. Although an investor could theoretically use the proceeds from any dividend payments to simply buy more stock in the same company, when an investor increases his investment in a company by purchasing more stock the transaction occurs at market price. However, when the same investor sees his investment in a company increase because earnings are retained rather than paid as a dividend, the reinvestment occurs at book value. Stated within the context of the DCF terminology: earnings retained in the business earn at the future expected return on book equity "r," and dividends used to purchase new stock earn at the rate "k." When the market price exceeds book value (that is, the market-to-book ratio exceeds 1.0), retained earnings are worth more than earnings paid out as a dividend because "r" will be higher than "k." Conversely, when the market price is below book value, "k" will be higher than "r," meaning that earnings paid out as a dividend earn a higher rate than retained earnings.

Q. IF RETAINED EARNINGS WERE MORE VALUABLE WHEN THE MARKET-TO-BOOK RATIO IS ABOVE 1.0, WHY WOULD A COMPANY WITH A MARKET-TO-BOOK RATIO ABOVE 1.0 PAY A DIVIDEND RATHER THAN RETAIN ALL OF THE EARNINGS?

A. Retained earnings are only more valuable than dividends if there are sufficient opportunities to profitably reinvest those earnings. Regulated utility companies are only allowed to earn the cost of capital on assets that are used and useful in providing safe and adequate utility service. Investing in assets that are not needed may not produce any return at all.

Opportunities for unregulated companies to reinvest funds are limited by the demands of the business. How many new computer chips can Intel profitably develop at the same time?

Q. IS THE DCF METHOD STILL VALID WHEN MARKET-TO-BOOK RATIOS ARE DIFFERENT THAN ONE?

A. Yes. It is old methods like the P/E ratio whose accuracy deteriorates as the market-to-book ratio varies from unity. The DCF model is specifically designed to recognize the difference in the value of earnings paid out as a dividend and retained earnings, a properly applied DCF model maintains its accuracy irrespective of the market-to-book ratio.

Q. HAVE YOU SEEN WITNESSES IN PUBLIC UTILITY RATE PROCEEDINGS CLAIM THAT THE DCF METHOD LOSES ITS ACCURACY AS THE MARKET-TO-BOOK RATIO VARIES FROM 1.0?

A. Yes. However, such statements are unwarranted. The basis for and the very development of the DCF model is to provide a mathematical model that produces a reliable result irrespective of the market to book ratio. It is the older, more basic, Earnings to Price ratio method that the DCF method replaced which suffers from the problem of needing a market to book ratio of 1.0 to work.

Q. UNDER THE NON-CONSTANT DCF MODEL, IS IT NECESSARY FOR EARNINGS AND DIVIDENDS TO GROW AT A CONSTANT RATE FOR THE MODEL TO BE ABLE TO ACCURATELY DETERMINE THE COST OF EQUITY?

A. No. Because the non-constant form of the DCF model separately discounts each and every future expected cash flow, it does *not* rely on any assumptions of constant growth. The dividend yield can be different from period to period, and growth can bounce around in any imaginable pattern without harming the accuracy of the answer obtained from quantifying those expectations. When the non-constant DCF model is correctly used, the answer obtained is as accurate as the estimates of future cash flow.

Q. IS THE NON-CONSTANT FORM OF THE DCF MODEL GENERALLY USED IN UTILITY RATE PROCEEDINGS?

A. Both forms are used, but the constant growth formula is more common (often referred to as the Gordon model).[39]

Q. HOW DID YOUR USE OF THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL CONFIRM YOUR RECOMMEDEND ROE.

A. By using the non-constant growth form of the DCF, the ROE for the Gas Group was between 8.28%[40](Median) and 8.95%[41](Mean). These results are directly derived from the Value Line forecasts of future cash flows and earnings projections.

d. EQUITY FINANCING COSTS

Q. HAVE YOU DETERMINED THE AMOUNT OF FINANCING COSTS TO BE INCLUDED IN THE COST OF EQUITY COMPUTATION?

A. The common stock of water companies is currently selling at a market price that is approximately 100% above book value.[42] As a result, when a water company sells new common stock, the effect is for the book value per share to increase. This makes selling

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[39] The constant growth model is generally recognized as first having been used in a utility rate proceeding by Dr. Myron Gordon. He demonstrated that it was possible to simplify the Williams DCF model for application to public utility companies.

[40] Schedule ALR 4, Page 2

[41] Ibid.

[42] Schedule ALR 3, page 1

new common stock a net profit center rather than a contributor to costs. Therefore, it is not necessary at this time to add any common equity financing cost allowance.

VI. ADDITIONAL COST OF EQUITY RISK FACTORS

Q. ARE THERE OTHER FACTORS ADDRESSED IN THIS PROCEEDING THAT COULD IMPACT CPA'S COST OF EQUITY?

A. Yes. CPA's Distribution System Improvement Charge (DSIC), use of a fully forecasted rate year, weather normalization adjustment (WNA) and CPA's proposed increased customer charge. Below I explain how each of these factors could impact CPA's cost of equity.

Q. WHAT IS THE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)?

A. The DSIC allows CPA to use a surcharge on customers' bills to accelerate the replacement of existing aging facilities without having to file a rate case. There is a 5% cap on DSIC surcharges and it does not permit O&M costs.

Q. DOES THE DSIC REDUCE CPA'S COST OF CAPITAL?

A. Yes. Bond rating agencies view provisions like the DSIC as credit positive for utilities, reducing their cost of capital. Moody's Investor Service[43] states "Because interim rate relief has a positive impact on utility cash flows and coverage metrics and reduces regulatory lag, Moody's views interim rate relief as a positive credit consideration."[44] They give a 25% weighting to cost recovery provisions and automatic adjustment clauses

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[43] Major credit rating agency

[44] Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, Moody's Investor Service, June 18, 2010

like the DSIC when determining the credit quality and credit rating in the regulated utility sector.[45]

Q. DOES MR. MOUL REDUCE HIS COST OF CAPITAL RECOMMENDATION TO ACCOUNT FOR RISK REDUCTIONS FROM CPA'S DSIC?

A. No. Regarding the DSIC and the CPA's cost of equity, Mr. Moul states "...whatever the benefit of a DSIC...that impact is already reflected in the market evidence of the cost of equity for the proxy group."[46]

Q. HAVE YOU DONE AN ANALYSIS TO DETERMINE TO WHAT DEGREE THE DSIC IS REFLECTED IN THE PROXY GROUP?

A. Yes. I determined that 42%[47] of the revenues of the companies in the proxy group (i.e., the Gas Group) are from non-regulated operations. Therefore, even if all the companies in the Gas Group apply a DSIC, or similar mechanism, to 100% of their regulated operations, 42% of revenues could not be impacted by such a regulatory mechanism.

Q. DOES THE USE OF A FUTURE FORECASTED TEST YEAR REDUCE CPA'S COST OF CAPITAL?

A. Yes. Like interim rate relieve, Moody's Investor Services views the use of forecasted test years as supporting a higher credit rating. Moody's makes the following statement regarding test years and credit ratings:

> ... Forward test years help to reduce regulatory lag and ensure that utility earns closer to its allowed rate of return. As a result, from a credit standpoint, Moody's

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[45] Ibid.
[46] Mr. Moul's Direct testimony, page 9, lines 22-24
[47] Schedule ALR 8

> views the use of forward test years as more supportive of utility credit quality than historical test years.[48]

Mr. Moul states "Knowledge of a company's credit quality is important because the cost of each type of capital is directly related to the associated risk of the firm" and "...these relative risk assessments also bear upon the cost of equity".[49]

Q. DOES AN INCREASED CUSTOMER CHARGE DECREASE CPA'S COST OF CAPITAL?

A. Yes. Fixed revenues are more protected from down turns in the overall economy than revenues based on usage. Therefore, if CPA's request to increase its customer charge from $16.75 to $20.60 is approved, CPA should receive a corresponding decrease in its cost of capital as its risk has been reduced. I note that OCA witness Jerome D. Mierzwa testified in OCA Statement 3 that CPA currently has the highest residential customer charge in the Commonwealth. This suggests that CPA's risk is already reduced, justifying a lower cost of capital.

Q. DOES CPA'S WEATHERIZATION NORMALIZATION ADJUSTMENT (WNA) DECREASE CPA'S COST OF CAPITAL?

A. In general, investors only demand compensation for non-diversifiable risks, i.e., risks that are tied to the overall economy. Normalizing revenues based on weather in general has nothing to do with the overall economy and thus nothing to do with non-diversifiable risks. However, as stated above, Moody's investor service does consider automatic adjustment clauses in their credit rating determinations and therefore a weather

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[48] Cost Recovery Provisions key to Investor Owned Utility Ratings and Credit Quality, Moody's Investors Service, June 18, 2010, page 8 of 19

[49] Mr. Moul's Direct testimony, page 13, lines 17-23

normalization clause such as the one used by CPA may have a slight positive increase in their credit rating and therefore a slight decrease in their cost of capital.

VII. MANAGEMENT PERFORMANCE

Q. SHOULD CPA'S COST OF EQUITY BE INCREASED TO ACCOUNT FOR THE COMPANY'S CLAIMED SUPERIOR PERFORMANCE?

A. No. The cost of equity for CPA should be based only on the return equity investors demand to invest in companies with similar risk to CPA. Mr. Moul claims that his proposed return fulfills the standards established by the landmark Bluefield and Hope cases. Regarding these cases he states:

> The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms.[50]

Charging consumers an additional return for management performance is inconsistent with the Bluefield and Hope cases. Furthermore, Mr. Moul presented no analysis on how he valued CPA's claimed superior performance to be 25 basis points, nor is there any indication that Mr. Moul evaluated whether CPA's performance is superior to, or more efficient, than those companies in the Gas Group.

VIII. ADDITIONAL COMMENTS ON MR. MOUL'S TESTIMONY

Q. PLEASE SUMMARIZE THE TESTIMONY OF MR. MOUL.

A. Mr. Moul has recommended that the Company be allowed a return on equity of 10.95%. He calculated an overall cost of capital of 6.69% with an 8.86% cost of equity. See

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[50] Mr. Moul's Direct testimony, page 3, lines 19-24 and page 4, lines 1-3

Schedule 1, page 1 of Mr. Moul's direct testimony. He arrived at his recommendation based upon his own versions of the Discounted Cash Flow ("DCF") Model, Risk Premium approach, Capital Asset Pricing Model ("CAPM Analysis") and the Comparable Earnings approach. Mr. Moul testified that, "...no one method or model of the cost of equity can be applied...rather, informed judgment must be used..."[51] Mr. Moul adds a leverage adjustment to his DCF result, a credit quality adjustment to his Risk Premium approach and the size adjustment to his CAPM method.

Mr. Moul applied his four cost of equity methods to his "Gas Group" of nine Gas Utility companies. Mr. Moul removed 2 of the 11 Gas Utility companies covered by The Value Line Investment Survey Standard Addition. NiSource was removed because of its electric, natural gas pipeline, and storage operations. UGI Corporation was removed because it is highly diversified. See Schedule 3, page 2 of 2 of Mr. Moul's direct testimony.

Below are the results of Mr. Moul's four cost of equity methods.

Method	**Gas Group**
DCF	10.05%
RP	11.75%
CAPM	11.90%
Comparable Earnings	13.55%

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[51] Mr. Moul's Direct Testimony, page 22, lines 18-20

Q. WHAT IS YOUR OVERALL REACTION TO MR. MOUL'S TESTIMONY?

A. Mr. Moul's cost of equity methods overstate the cost of equity, as I will explain below. His recommendations double charge consumers by adding 0.50% to account for "... the lower credit quality of CPA's parent company,"[52] while asking consumers to pay for expensive equity (1,402 basis points more than NiSource) of a capital structure that is much lower risk than the capital structure used by NiSource.

Mr. Moul's DCF result is 8.83% (8 basis points lower than my ROE recommendation) before adding 0.72% for a "leverage adjustment" and a "credit quality" adjustment. Mr. Moul's DCF result is reasonable in this case (8.83%[53]), before including his inappropriate adjustments. Below I will explain why Mr. Moul's adjustments are inappropriate and the flaws in Mr. Moul's DCF method despite getting a reasonable result this time.

DCF Method

Q. DOES MR. MOUL CONSIDER THE DCF METHOD HIS PRIMARY METHOD FOR DETERMINING THE COST OF EQUITY?

A. No. He claims that the DCF method has limitations.

Q. WHAT FORMULA DOES MR. MOUL USE IN HIS DCF ANALYSIS?

A. Dividend Yield (D/P) + Growth Rate (g) + leverage Adjustment (lev).[54]

Q. DOES MR. MOUL PROPERLY APPLY THE SIMPLIFIED OR CONSTANT DCF METHOD?

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[52] Mr. Moul's Direct testimony, page 18, line 18

[53] Ibid Schedule 1, page 2 of 2

[54] Ibid, page 36, lines 18-21

A. No. Mr. Moul adds a growth component to a divided yield even though his growth analysis gives earnings per share growth forecasts by analysts the greatest emphasis.[55] It is only a DCF method if the dividend yield is computed properly, and the growth rate used is derived from a careful study of what future sustainable growth in cash flow is anticipated by investors.

Q. HOW DID MR. MOUL CALCULATE HIS GROWTH RATE FOR HIS DCF METHOD?

A. On page 27, line 23 of Mr. Moul's testimony he says "...IBES/First Call, SNL Financial, Zacks, and Morning Star represent reliable authorities of projected growth upon which investors rely." On page 30, lines 8-11 Mr. Moul states, "Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is a reasonable growth rate for Columbia generated by accelerated investment in infrastructure." Below are the five-year projected earnings per share rates by the four investment research firms he chose:

IBES/First Call EPS:	5.11%
SNL:	5.04%
Zacks EPS:	5.11%
Morning Star:	5.19%
Value Line EPS:	6.94%
Value Line DPS:	4.44%
Value Line BVPS:	5.22%
Value Line CFPS:	5.83%
Value Line BxR:	5.06%

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[55] Mr. Moul's Direct testimony, page 28, lines 14-17

Source: Schedule 9, page 1 of 1, of Mr. Moul's direct testimony.

Only 2 forecasts out of 9 considered are higher than Mr. Moul's growth rate of 5.25%.

Q. IS MR. MOUL'S METHODOLOGY TO DETERMINE THE GROWTH RATE TO USE IN HIS DCF MODEL APPROPRIATE?

A. No. Mr. Moul mentions the "b x r" method on page 26 of his direct testimony but he does not use it. As stated above, Mr. Moul makes the error of using analyst five-year earnings per share growth without even attempting to reconcile the retention rate use for computing growth with the retention rate he used to compute the dividend yield. This is analogous to failing to reconcile the money you are taking out of your checking account with your future balance, i.e. the basic balancing of a checkbook.

Q. CAN YOU PLEASE SUMMARIZE WHY A FUTURE ORIENTED "B X R" METHOD IS SUPERIOR TO A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE FORECAST IN PROVIDING A LONG-TERM SUSTAINABLE GROWTH RATE?

A. Yes. The primary cause of sustainable earnings growth is the retention of earnings. A company is able to create higher future earnings by retaining a portion of the prior year's earnings in the business and purchasing new business assets with those retained earnings. There are many factors that can cause short-term swings in earnings growth rates, but the long-term sustainable growth is caused by retaining earnings and reinvesting those earnings. Factors that cause short-term swings include anything that causes a company to earn a return on book equity at a rate different from the long-term sustainable rate. Assume, for example, that a particular utility company is regulated so that it is provided with a reasonable opportunity to earn 9.0% on its equity. If the company should experience an event such as the loss of several key customers, or unfavorable weather conditions which cause it to earn only 6.0% on equity in a given year, the drop of 9% earned return on equity to a 6% earned return on equity would be concurrent with a very large drop in earnings per share. In fact, if accompany did not issue any new shares of stock during the year, a drop form a 9% earned return on book equity to a 6% earned return on book equity would result in a 33.3% decline in earnings per share over the period.[56] However, such a drop in earnings would not be any indication of what is a long-term sustainable earnings per share growth rate. If the drop were caused by weather conditions, the drop in earnings would be immediately offset once normal weather conditions return. If the drop were from the loss of some key customers, the company would replace the lost earnings by filing for a rate increase to bring revenues up to the level required for the company to be given a reasonable opportunity to recover its cost of equity.

For the above reasons, changes in earnings per share growth rates that are caused by non-recurring changes in the earned return on book equity are inconsistent with long-term sustainable growth, but changes in earnings per share because of the reinvestment of additional assets is a cause of sustainable earnings growth. The "b x r" term in the DCF equation computes sustainable growth because it measures only the growth which a company can expect to achieve when its earned return on book equity "r" remains in equilibrium. If analysts have sufficient data to be able to forecast varying values of "r" in future years, then a complex, or multi-stage DCF method must be used to accurately quantify the effect. Averaging growth rates over sub-periods, such as averaging growth

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[56] By definition, earned return on equity is earnings divided by book value. Therefore, whatever level of earnings is required to produce earnings of 6% of book would have to be 33.3% lower that the level of earnings required to produce a return on book equity of 9%.

over the first five years with a growth rate expected over the subsequent period, will not provide an appropriate representation of the cash flows expected by investors in the future and, therefore, will not provide an acceptable method of quantifying the cost of equity using the DCF method. The choices are either a constant growth DCF, in which one "b x r" derived growth rate should be used, or a complex DCF method in which the cash flow anticipated in each future year is separately estimated. Mr. Moul has done neither.

Q. WHY ARE ANALYSTS FIVE-YEAR CONSENSUS GROWTH RATES NOT INDICATIVE OF LONG-TERM SUSTAINABLE GROWTH RATES?

A. Analysts' five-year earnings per share growth rates are earnings per share growth rates that measure earnings growth from the most currently completed fiscal year to projected earnings five years into the future. These growth rates are not indicative of future sustainable growth rates in part because the sources of cash flow to an investor are dividends and stock price appreciation. While both stock price and dividends are impacted in the long-run by the level of earnings a company is capable of achieving, earnings growth over a period as short as five years is rarely in synchronization with the cash flow growth from increases in dividends and stock prices. For example, if a company experiences a year in which investors perceive that earnings temporarily dipped below normal trend levels, stock prices generally do not decline at the same percentage that earnings decline, and dividends are usually not cut just because of a temporary decline in a company's earnings. Unless both the stock price and dividends mirror every down swing in earnings, they cannot be expected to recover at the same growth rate that earnings recover. Therefore, growth rates such as five-year projected growth in earnings per share are not indicative of long-term sustainable growth rates in cash flow. As a result, they are inapplicable for direct use in the simplified DCF method.

Q. IS THE USE OF FIVE-YEAR EARNINGS PER SHARE GROWTH RATES IN THE DCF MODEL ALSO IMPROPER?

A. A raw, unadjusted, five-year earnings per share growth rate is usually a poor proxy for either short-term or long-term cash flow that an investor expects to receive. When implementing the DCF method, the time value of money is considered by equating the current stock price of a company to present value of the future cash flows that an investor expects to receive over the entire time that he or she owns the stock. The discount rate required to make the future cash flow stream, on a net present value basis, equal to the current stock price is the cost of equity. The only two sources of cash flow to an investor are dividends and the net proceeds from the sale of stock at whatever time in the future the investor finally sells. Therefore, the DCF method is discounting future cash follows that investors expect to receive from dividends and from the eventual sale of the stock. Five-year earnings growth rate forecasts are especially poor indicators of cash flow growth even over the five years being measured by the five-year earnings per share growth rate number.

Q. WHY IS A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATOR OF THE FIVE-YEAR CASH FLOW EXPECTATION FROM DIVIDENDS?

A. The board of directors changes dividend rates based upon long-term earnings expectations combined with the capital needs of a company. Most companies do not cut the dividend simply because a company has a year in which earnings were below sustainable trends, and similarly they do not increase dividends simply because earnings for one year happened to be above long-term sustainable trends. Therefore, over any give five-year period, earnings growth is frequently very different from dividend growth. In order for earnings growth to equal dividend growth, at a minimum, earnings per share in the first year of the five-year earnings growth rate period would have to be exactly on the long-term earnings trend line expected by investors. Since earnings in most years are with above or below the trend line, the earnings per share growth rate over most five-year periods is different from what is expected for earnings growth.

Q. WHY IS THE FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATION OF FUTURE STOCK PRICE GROWTH?

A. If a company happens to experience a year in which earnings decline below what investors believe are consistent with the long-term trend, then the stock price does not drop anywhere near as much as earnings drop. Similarly, if a company happens to experience a year in which earnings are higher than the investor-perceived long-term sustainable trend, then the stock price will not increase as much as earnings. In other words, the P/E (price/earnings) ratio of a company will increase after a year in which investors believe earnings are below sustainable levels, and the P/E ratio will decline in a year in which investors believe earnings are higher than expected. Since it is stock price that is one of the important cash flow sources to an investor, a five-year earnings growth rate is a poor indicator of cash flow both because it is a poor indicator of stock price growth over the five years being examined and is equally a poor predictor of dividend growth over the period.

Q. ARE YOU SAYING THAT ANALYSTS' CONSENSUS EARNINGS PER SHARE GROWTH RATES ARE USELESS AS AN AID TO PROJECTING THE FUTURE?

A. No. Analysts' EPS growth rates are, however, very dangerous if used in a simplified DCF without proper interpretation. While they are not useful if used in their "raw" form, they can be useful in computing estimates of what earned return on equity investors expect will be sustained in the future, and as such, are useful in developing long-term sustainable growth rates.

Q. BESIDES GROWTH RATE, ARE THERE ANY OTHER DCF ANALYSIS INPUTS THAT MR. MOUL HAS ESTIMATED INCORRECTLY?

A. Yes. Mr. Moul made an unjustifiable "leverage adjustment."

Q. PLEASE DESCRIBE THE LEVERAGE ADJUSTMENT PROPOSED BY MR. MOUL IN THIS PROCEEDING.

A. Mr. Moul has proposed a leverage adjustment addition to his DCF derived cost of equity, stating "In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used with modification." See page 33, lines 1-3 of Mr. Moul's direct testimony. He then goes on to say there is: "Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity." See Page 33, lines 18-21 of Mr. Moul's direct testimony. Because of this alleged higher financial risk, Mr. Moul recommends adding 0.72%[57] to the DCF derived cost of equity.

Q. JUST BECAUSE THE MARKET VALUE CAPITAL STRUCTURE CONTAINS A HIGHER PERCENTAGE OF COMMON EQUITY THAN BOOK VALUE CAPITAL STRUCTURE, DOES THIS MEAN THE MARKET VALUE CAPITAL STRUCTURE HAS LOWER FINANCIAL RISK THAN THE BOOK VALUE CAPTIAL STRUCTURE?

A. No. Market value capital structure and book value capital structure are two completely different ways of measuring the same thing. Concluding that a market value capital structure is lower in risk because it contains more equity than the book value based capital structure for the same company is as inconsistent and illogical as claiming that a person who weighs 150 pounds could lose weight simply by stepping on a scale that measures weight in kilos instead of pounds. Financial risk is determined by a company's ability to meet its cash flow obligations. The most common and perhaps most important single measure of financial risk is the pretax interest coverage ratio. The interest coverage ratio is computed by dividing the sum of interest expense and pre-tax income by interest expense. This number is useful because it gives bondholders a sense of how far earnings would have to decline before a company would not be able to meet its interest payments. For example, if a company has an interest coverage ratio of 3.0, this means that at its current earnings rate, its earnings available for both payment of interest and pre-tax earnings is three times as much as is needed to make its interest payments.

Q. DOES A DECLINE IN MARKET PRICE LOWER THE COVERAGE RATIO?

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[57] Mr. Moul's Direct testimony, page 36, lines 1-2

A. Lowering of the market value does not directly cause a change in the coverage ratio computation. Therefore, changing from a market value orientation to a book value orientation does not more to change a company's financial risk than the weight of a person was influenced by switching to a scale calibrated in kilos instead of pounds.

Q. DO INVESTORS UNDERSTAND THAT AS PART OF THE REGULATORY PROCESS ALLOWED RETURNS ARE APPLIED TO BOOK VALUE?

A. Yes they do. This is a process that has been going on for decades and it is hard to argue that investors are not aware of this. By recommending this leverage adjustment, Mr. Moul is implying that investors forget this after each rate case. Evaluating the cost of equity based on a comparative group is like taking a snapshot of their expectations. After this snapshot it taken, it is then applied to the individual company so even if the allowed return affected the expectation of the investors in the comparative group it would be after the snapshot was taken.

Q. DOES MR. MOUL'S LEVERAGE ADJUSTMENT GO AGAINST ORIGNAL COST RATEMAKING?

A. Yes. Mr. Moul says on page 31, lines 17-21 of his direct testimony that, "If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital based on a book value capital structure used for rate setting purposes, the utility will not, by definition, recover its risk-adjusted capital cost." In other words, Mr. Moul is saying that as a consequence of original cost ratemaking an upward adjustment is needed. When a company has a market to book value above 1, and is thus over earning, applying the correct rate of return to the book value could have downward pressure on the stock price. No matter what logic is applied to the reason for adding a value to the rate of return, the leverage adjustment distorts the natural market dynamic between a regulated utility's stock price and its allowed rate of return.

Risk Premium Method

Q. PLEASE EXPLAIN MR. MOUL'S VERSION OF THE RISK PREMIUM METHODS, AS PRESENTED IN HIS DIRECT TESTIMONY.

A. Mr. Moul calculates an equity risk premium of large company stocks over long-term corporate bonds based on historical data between 1926-2013 and presents the results in three categories based on the relative level of interest rates.

Category	Equity Risk Premium
Low Interest Rate	7.60%
Average Across All Interest Rates	5.79%
High Interest Rates	3.98%

See Schedule12, page 1 of Mr. Moul's direct testimony.

He adds an additional 50 basis points to account for the Company's relative credit quality for the period as he does for the DCF method.[58]

Q. PLEASE COMMENT ON MR. MOUL'S RISK PREMIUM METHOD.

A. Mr. Moul's equity risk premium of 6.50%[59] is out of line with market data, academic studies and surveys of CFOs and global managers. The Campbell and Harvey Survey of CFOs (2014) showed an average equity risk premium estimate of 3.73%. From a historical perspective, Roger Ibbotson has stated that the historical equity risk premium is

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[58] Mr. Moul's Direct Testimony, Schedule 1, Page 2 of 2

[59] Mr. Moul's Direct Testimony, Page 42, line 6

the geometric difference between company stock returns and U.S. Treasury returns.[60] Calculated this way, the historical risk premium for large company stocks is 4.10% with long-term government bond returns as the risk free rate.[61]

CAPM Method

Q. PLEASE SUMMARIZE MR. MOUL'S CAPM METHOD.

A. Mr. Moul explains that, "to compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return."[62] He uses a risk free rate of 3.75% based on interest rate forecasts and recent trends in long term Treasury yields.[63] The market premium portion of his CAPM analysis is done based on both historical data (Value Line and S&P 500 returns) and forecasted returns (DCF analyses for both the S&P 500 Index and Value Line data).[64] He adds a "mid-cap adjustment" of 1.14% to account for the average equity capitalization of the Gas Group.[65]

Q. DO YOU AGREE WITH THE RESULTS OF MR. MOUL'S CAPM ANALYSIS?

A. No, I do not agree with results of Mr. Moul's CAPM analysis because I believe that they significantly and inaccurately overstate the Company's cost of equity.

1. The arithmetic average return that Mr. Moul uses overstates the historical risk premium by 200 basis points. The Ibbotson SBBI® 2013 Classic Yearbook shows that investors actually earned a compounded annual return of 9.8%

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[60] Ibbotson SBBI® 2013 Classic Yearbook, page 64

[61] Ibid 9.8 (compound annual return of large company stocks – 1926-2012) – 5.7 (compound annual return of long-term government bonds)

[62] Ibid. Page 43, lines 4-7

[63] Ibid. Page 45, lines 21-22

[64] Ibid. Page 46, lines 1-3 and lines 16-22

[65] Ibid. Page 47, lines 15-16

between 1926 and 2012. The arithmetic mean return of 11.8% is possibly valuable to stock brokers and fund managers attempting to predict future bonuses, but not for calculating the cost of equity. A Dow Jones Newswire article stated, "Some financial advisers rely too heavily on a formula known as the arithmetic average, which can be misleading when investing for the long term. Financial advisors who use this formula may be overstating your potential profit and leading you to take risks you might otherwise avoid..."[66]

2. His prospective risk premium calculation is based on a DCF analysis that is not based on sustainable growth. His DCF analysis based on the Value Line data has a growth component of an astounding 10.88% and his DCF results for the S&P 500 Index also include an unreasonably high growth rate of 9.59%.[67]

Q. IS MR. MOUL'S ADDER FOR A SMALL SIZE EFFECT AN APPROPRIATE PART OF A CAPM ANALYSIS?

A. No, Mr. Moul's premium adder for the relative small size of CPA is unjustifiable. A proper analysis of the data from Ibbotson SBBI/Morningstar shows that size is a diversifiable risk and therefore does not impact the cost of equity. Professor Aswath Damodaran said the following regarding the supposed "small cap premium:

> Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is an extremely sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor).[68]

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[66] Kaja Whitehouse, To Financial Advisors and Fuzzy Math, Dow Jones Newswires October 8, 2003

[67] Mr. Moul's Testimony, Schedule 13, page 2 of 3

[68] Aswath Damodaran, Equity Risk Premiums (ERP): Determinates, Estimation and Implications – The 2014 Edition (paper updated, March 2015). Page 42

Comparable Earnings Method

Q. PLEASE EXPLAIN THE COMPARABLE EARNINGS METHOD PRESENTED BY MR. MOUL.

A. Mr. Moul selected a group of non-regulated companies that he believes to be of comparable risk to the Gas Group. After selecting the companies, he presents the historic and Value Line expected return on book equity. See Schedule 14, page 2 of 2 of Mr. Moul's direct testimony. The final column of numbers on this table is the "Projected 2017-19." However, what he labels as the projected 2017-19 return is actually the return on book equity that Value Line forecasts, not the return that Value Line projects investors will receive on their investment as a result of purchasing the common stock at current prices. According to Mr. Moul's Schedule 14, the total return expected by Value Line on the book equity of these industrial companies is between a 9.50% and a high of 37.0%, for an average of 19.3% (13.6% excluding companies with values > 20%).

Q. IS THIS METHOD VALID?

A. No. Mr. Moul has attempted to determine the cost of equity that would be demanded by investors on the market price of a company comparable to CPA by comparing it to the historic and projected returns on book equity of a selection of industrial companies. Leaving aside the problems with actually being able to select companies that are comparable, the overriding problem with Mr. Moul's comparable earnings analysis is that it did not address the cost of equity at all. It simply considered the returns on book equity that were achieved, and are expected to be achieved by Value Line in the next 3 to 5 years. The earned return on book equity is an entirely different concept from the cost of equity.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. MOUL'S TESTIMONY.

A. Mr. Moul recommends that the Company be allowed a return on equity of 10.95%. Mr. Moul's DCF result of 10.05% is high because he adds a leverage adjustment that misrepresents the basics of evaluating a company's cost of equity, and a "credit quality" premium based on the credit quality of the parent NiSource while recommending a capital structure with consider more equity. Without his leverage adjustment and credit quality addition is DCF result is 8.83%.

Mr. Moul's Risk Premium method was developed based upon an improper mathematical approach to quantifying historic actual returns. Mr. Moul's CAPM approach relies on invalid implementations of the DCF method to quantify the projected cost of equity, an improper inflation of the "beta"[69]because of a high market-to-book ratio, and he adds the invalid "size premium." The incorrect claim that investors demand a higher cost of equity to invest in a small company (referred to as "size premium") is manufactured by an incorrect use of data. Mr. Moul's Comparable Earnings method is not really an equity costing method at all, as no consideration was given to investor's reactions to the earned returns on book equity.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. Based on the evidence presented in my testimony I conclude that the cost of equity allowed for the Company should be 8.88% and an overall cost of capital of 6.72% (See Schedule ALR 1, page 1) based on the actual capital structure of the Gas Group. If

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[69] Beta is a measure of non-diversifiable risk.

the Commission decides that the evidence of this specific case supports the use of the Company's requested capital structure I recommend using a lower cost of equity (8.34%) to set rates to account for the lower financial risk of a higher common equity ratio results in an overall cost of capital of 6.76%. This recommendation is contingent on acceptance of the OCA's recommendation to retain the current residential customer charge.

Mr. Moul's cost of equity recommendation of 10.95% is unreasonably high because of errors in his cost of equity calculations as I explained in my testimony. His recommendation double charges consumers by adding 0.50% to account for "... the lower credit quality of CPA's parent company"[70] while asking consumers to pay for expensive equity (1,402 basis points more than NiSource[71]) of a capital structure that is much lower risk[72] than the capital structure used by NiSource.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[70] Ibid. Page 18, line 18

[71] 52.21% (Mr. Moul's recommended common equity ratio) – 38.18% (NiSource's common equity ratio) = 1,402 basis points

[72] Mr. Moul states "...a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk". See pages 15, line 21 and page 16, lines 1-2 of Mr. Moul's Direct Testimony.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Aaron L. Rothschild, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 2, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: Aaron L. Rothschild
Aaron L. Rothschild

Consultant Address:
15 Lake Road
Ridgefield, CT 06877

DATED: 6/18/2015

OCA STATEMENT No. 2

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
v. :
: Docket No. R-2015-2468056
:
Columbia Gas of Pennsylvania, Inc. :

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

AARON L. ROTHSCHILD

ON BEHALF OF

THE OFFICE OF CONSUMER ADVOCATE

June 19, 2015

Columbia Gas of Pennsylvania, Inc.
Overall Cost of Capital
Actual GAS Group Capital Structure Ratios

	Ratios	Cost Rate	Weighted Cost Rate [D]
Long-Term Debt	42.57% [A]	5.31% [B]	2.26%
Short-Term Debt	10.69% [A]	2.86% [B]	0.31%
Common Equity*	46.75% [A]	8.88% [C]	4.15%
	100.0%		6.72%

*Includes Preferred stock totally less than 0.2% of the total capital structure

Source:

[A]	SCHEDULE ALR 6, Page 1
[B]	Mr. Moul's Direct Testimony, Schedule No. 1, page 1 of 2
[C]	SCHEDULE ALR 2
[D]	Ratios times Cost Rate

Columbia Gas of Pennsylvania, Inc.
Overall Cost of Capital
Company Requested Capital Structure
December 31, 2016 Company's Fully Forecasted Rate Year

	Ratios	Cost Rate	Weighted Cost Rate [C]
Long-Term Debt	42.65% [A]	5.31% [A]	2.26%
Short-Term Debt	5.14% [A]	2.86% [A]	0.15%
Common Equity*	52.21% [A]	8.34% [B]	4.35%
	100.0%		6.76%

Source:

[A] Mr. Moul's Direct Testimony, Schedule No. 1, page 1 of 2
[B] SCHEDULE ALR 2
[C] Ratios times Cost Rate

SCHEDULE ALR 2

COLUMBIA GAS OF PENNSYLVANIA, INC.

COST OF EQUITY SUMMARY

	Average for Year ending 5/31/15		As of 5/31/2015	
SIMPLIFIED, OR CONSTANT GROWTH DCF (D/P +g) RESULTS:				
GAS GROUP	8.87%	[A]	8.90%	[A]
NON-CONSTANT GROWTH DCF METHOD				
GAS GROUP			8.95%	[B]
Indicated Cost of Equity		8.87%	to	**8.90%**
	Midpoint of Range		**8.88%**	
Cost of Equity Reduction for Lower Risk of Requested Capital Structure:		[C]	**0.55%**	

[A] SCHEDULE ALR 4, page 1
[B] SCHEDULE ALR 4, Page 2
[C] (52.21% - 46.25%)*.01.
Based on Rothschild Financial Consulting Study regarding
The relationship between cost of equity and capital common
equity ratios

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
			Book	Book	Book	Book	Market Price			Market to Book			Dividend Yield	
		VL Issue	Per Sh. Dec. 11	Per Sh. Dec. 12	Per Sh. Dec. 13	Per Sh. Dec. 14	At 05/31/15	High for Year	Low for Year	At 05/31/15	Avg. for Year	Div. Rate	At 5/31/2015	Avg. for Year
			[A]	[A]	[A]	[A]	[B]	[B]	[B]	[C]	[C]	[A]	[D]	[D]
FINANCIAL DATA FOR GAS GROUP														
AGL Resources	GAS		$28.33	$28.96	$30.54	$31.63	$50.37	$57.75	$46.50	1.59	1.68	$2.04	4.05%	3.91%
Atmos Energy Corp	ATO		$24.98	$26.14	$28.47	$30.74	$54.02	$59.35	$46.64	1.76	1.79	$1.56	2.89%	2.94%
Laclede Group	LG		$25.56	$26.67	$32.00	$34.93	$53.51	$55.75	$44.96	1.53	1.50	$1.84	3.44%	3.65%
NRG Energy	NRG		$32.61	$31.82	$31.70	$36.15	$25.20	$38.09	$22.78	0.70	0.90	$0.58	2.30%	1.91%
N.W. Nat'l Gas	NWN		$26.70	$27.23	$27.77	$28.60	$44.70	$52.57	$41.81	1.56	1.67	$1.86	4.16%	3.94%
Piedmont Nat'l Gas	PNY		$13.79	$14.21	$15.87	$16.80	$37.29	$41.09	$33.38	2.22	2.28	$1.28	3.43%	3.44%
South Jersey Inds.*	SJI		$20.66	$23.26	$25.28	$26.45	$26.39	$61.23	$25.63	1.00	1.68	$2.05	7.77%	4.72%
Southwest Gas	SWX		$26.66	$28.35	$30.47	$31.95	$54.46	$64.20	$47.21	1.70	1.78	$1.62	2.97%	2.91%
WGL Holdings	WGL		$23.49	$26.64	$24.65	$24.08	$57.54	$59.08	$37.77	2.39	1.99	$1.85	3.22%	3.82%
	AVERAGE		$24.75	$25.92	$27.42	$29.04	$44.63	$54.35	$38.52	1.61	1.70	$1.63	3.80%	3.47%
	MEDIAN									1.59	1.68		3.43%	3.65%

*Dividend rate based on Value 2015 Forecast

Sources:		
	[A]	Most current Value Line at time of prep. of schedule. Most current quarterly dividend rate X 4 For South Jersey Industries, used 2015 annual figure because quarterly dividend data was not available
	[B]	Yahoo Finance -- Historical Prices
	[C]	Market price divided by book value
	[D]	Dividend rate divided by market price

GAS GROUP
EARNINGS PER SHARE AND RETURN ON EQUITY

		[1] EPS 2011	[2] EPS 2012	[3] EPS 2013	[4] EPS 2014	[5] Return on Eq. 2013	[6] Return on Eq. 2014	[7] Value Line Future Exp. Return on Eq.	[8] Return on Equity 2012
		[A]	[A]	[A]	[A]	[B]		[A]	
AGL Resources	GAS	$2.12	$2.31	$2.64	$4.71	8.87%	15.15%	11.50%	8.06%
Atmos Energy Corp	ATO	$2.26	$2.10	$2.50	$2.96	9.16%	10.00%	10.50%	8.22%
Laclede Group	LG	$2.86	$2.79	$2.02	$2.35	6.89%	7.02%	8.50%	10.68%
NRG Energy	NRG	$0.78	$2.35	$1.22	$0.23	3.84%	0.68%	4.50%	7.29%
N.W. Nat'l Gas	NWN	$2.39	$2.22	$2.24	$2.25	8.15%	7.98%	9.00%	8.23%
Piedmont Nat'l Gas	PNY	$1.57	$1.66	$1.78	$1.84	11.84%	11.26%	10.50%	11.86%
South Jersey Inds.*	SJI	$2.90	$3.03	$3.03	$3.13	12.48%	12.10%	14.50%	13.80%
Southwest Gas	SWX	$2.43	$2.86	$3.11	$3.01	10.57%	9.64%	12.00%	10.40%
WGL Holdings	WGL	$2.25	$2.68	$2.31	$2.68	9.01%	11.00%	11.00%	10.69%
	AVERAGE	$2.17	$2.44	$2.32	$2.57	8.98%	9.43%	10.22%	9.92%
	MEDIAN					9.01%	10.00%	10.50%	10.40%

Source:	[A] Most current Value Line at time of prep. of schedule.
	[B] Earnings Per Share divded by average book value. Book value shown on

RETURN ON EQUITY IMPLIED IN ZACKS GROWTH RATES

GAS GROUP

EARNINGS PER SHARE AND RETURN ON EQUITY

		Dec. 14 Y/E Book [3] [A]	Earnings 2014 [A]	Dividends [A]	Analyst 5 Year Growth Rate [B]	Y/E Book in 2018 at Zack's Growth Before SV [C]	Y/E Book in 2019 at Zack's Growth Before SV [C]	Growth In Book Value From SV	Y/E Book in 2014 at Zack's Growth Including SV	Earnings 2019 at Zack's Growth [C]	Return on Equity to achieve Analysts' Growth [C]	VALUE LINE BETA [A]
AGL Resources	GAS	$31.63	$4.71	$2.04	6.00%	$44.01	$47.58	106.45%	$48.75	$6.30	12.93%	0.80
Atmos Energy Corp	ATO	$30.74	$2.96	$1.56	7.00%	$37.39	$39.35	132.11%	$50.70	$4.15	8.19%	0.85
Laclede Group	LG	$34.93	$2.35	$1.84	4.90%	$37.23	$37.88	105.84%	$39.75	$2.99	7.51%	0.70
NRG Energy	NRG	$36.15	$0.23	$0.58		$34.75	$34.40	100.62%	$34.79	$0.23	0.66%	0.95
N.W. Nat'l Gas	NWN	$28.60	$2.25	$1.86	4.00%	$30.32	$30.80	116.85%	$35.71	$2.74	7.67%	0.70
Piedmont Nat'l Gas	PNY	$16.80	$1.84	$1.28	5.00%	$19.33	$20.05	100.93%	$19.87	$2.35	11.82%	0.80
South Jersey Inds.*	SJI	$26.45	$3.13	$2.05		$30.77	$31.85	100.00%	$31.31	$3.13	10.00%	0.80
Southwest Gas	SWX	$31.95	$3.01	$1.62	5.50%	$38.32	$40.13	110.09%	$43.18	$3.93	9.11%	0.85
WGL Holdings	WGL	$24.08	$2.68	$1.85	6.00%	$27.92	$29.03	109.23%	$31.10	$3.59	11.53%	0.75
	AVERAGE	$29.04	$2.57	$1.63	5.49%	$33.34	$34.56	114.80%		$3.27	8.82%	0.80
	MEDIAN				5.50%						9.11%	0.80

[A] Most Current Value Line

[B] Most Current - Zacks.com

Zacks published "NA" for NRG Energy and Sourth Jersey Inds.

[C] Projected return on equity is obtained by escalating both dividends and earnings per share by the stated growth rate, and adding earnings and subtracting

SCHEDULE ALR 4, page 1

CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) INDICATED COST OF EQUITY GAS GROUP

		BASED ON AVERAGE *MARKET PRICE* FOR Year Ending 5/31/15	BASED UPON *MARKET PRICE* AS OF 5/31/2015
1 Dividend Yield On Market Price	[B]	3.47%	3.80%
2 Retention Ratio:			
a) Market-to-book	[B]	1.70	1.61
b) Div. Yld on Book	[C]	5.89%	6.11%
c) Return on Equity	[A]	10.50%	10.50%
d) Retention Rate	[D]	43.88%	41.83%
3 Reinvestment Growth	[E]	4.61%	4.39%
4 New Financing Growth	[F]	0.70%	0.61%
5 Total Estimate of Investor Anticipated Growth	[G]	5.30%	5.00%
6 Increment to Dividend Yield for Growth to Next Year	[H]	0.09%	0.10%
7 Indicated Cost of Equity	[I]	8.87%	8.90%

Some of the Considerations for determining Future Expected Return on Equity:

			Median	Mean	Source:
[A]	Value Line Expectation		**10.50%**	**10.22%**	SCHEDULE ALR 3, Page 2
	Return on Equity to Achieve Zack's Growth		9.11%	8.82%	SCHEDULE ALR 3, Page 3
	Earned Return on Equity in	2014	10.00%	9.43%	SCHEDULE ALR 3, Page 2
	Earned Return on Equity in	2013	9.01%	8.98%	SCHEDULE ALR 3, Page 2
	Earned Return on Equity in	2012	10.40%	9.92%	SCHEDULE ALR 3, Page 2

[B] SCHEDULE ALR 3, Page 1

[C] Line 1 x Line 2a

[D] 1- Line 2b/Line 2c

[E] Line 2c x Line 2d

[F] S X V (S = the rate of continuous new stock financing, V = rate of return on common equity investment)

[M/B X (Ext. Fin Rate+1)/(M/B + Ext. Fin. Rate-1) Ext. Fin. rate used = 1.00% [J]

[G] Line 3 + Line 4

[H] Line 1 x one-half of line 5

[I] Line 1 + Line 5 + Line 6

[J] SCHEDULE ALR 5, page 1

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) INDICATED COST OF EQUITY
BASED ON VALUE LINE'S FORECAST
GAS GROUP

		AGL Resources **GAS**	**Atmos Energy Corp** **ATO**	**Laclede Group** **LG**	**New Jersey Res.** **NGR**	**N.W. Nat'l Gas** **NWN**	**Piedmont Nat'l Gas** **PNY**	**South Jersey Inds.** **SJI**	**Southwest Gas** **SWX**	**WGL Holdings** **WGL**	Source
Value Line Date		**3/6/2015**	**3/6/2015**	**3/6/2015**	**3/27/2015**	**3/6/2015**	**3/6/2015**	**3/6/2015**	**3/6/2015**	**3/6/2015**	
Dividend	2015	$2.04	$1.56	$1.84	$0.62	$1.87	$1.31	$2.05	$1.62	$1.85	Value Line
	2016	$2.10	$1.64	$1.92	$0.70	$1.91	$1.35	$2.20	$1.74	$1.87	Based on Value Line, assuming constant dividend growth
	2017	$2.20	$1.72	$2.01	$0.74	$1.97	$1.39	$2.34	$1.85	$1.87	Based on Value Line, assuming constant dividend growth
	2018	$2.30	$1.81	$2.10	$0.79	$2.03	$1.43	$2.49	$1.97	$1.87	Value Line
	2019	$2.40	$1.90	$2.20	$0.84	$2.10	$1.47	$2.65	$2.10	$1.87	
Forecasted dividend growth rate		4.55%	5.03%	4.64%	6.27%	3.21%	2.88%	6.40%	6.47%	0.00%	Compound annual rate of growth in dividends from 2014 to 2017
Book Value											
	2015	$35.35	$31.85	$36.20	$37.25	$29.65	$17.40	$28.55	$32.30	$25.15	Value Line
	2019	$40.70	$36.65	$48.10	$43.95	$36.15	$20.40	$34.20	$32.65	$30.00	Value Line
Total return on equity to investor who purchased stock on 4/30/15 and sold stock on 4/30/2019 assuming Value Line projections of dividends and book value are correct and assuming stock price grows at same rate as book value											
Stock Price	5/31/2015	$50.37	$54.02	$53.51	$25.20	$44.70	$37.29	$26.39	$54.46	$57.54	SCHEDULE ALR 3, Page 1
	5/31/2019	$57.99	$62.16	$71.10	$29.73	$54.50	$43.72	$31.61	$55.05	$68.64	Increase in stock price at same rate as forecasted increase in book value
VL Midpoint stock price forecast		$70.00	$62.50	$65.00	$30.00	$55.00	$37.50	$70.00	$62.50	$50.00	
Cash Flow from purchasing stock in 2015, receiving dividends through 2019, and selling the stock in 2019 Negative number in 2015 reflects cash outflow required to purchase stock Cash flow sources are 1) dividends, and 2) proceeds of stock sale											
	1Q Dividend	0.51	0.39	0.46	0.145	0.465	0.32	0	0.365	0.463	
Cash flow does not include 1Q dividend paid on March 31, 2015	2015	($48.84)	($52.85)	($52.13)	($24.73)	($43.30)	($36.30)	($24.34)	($53.21)	($56.15)	
	2016	$2.10	$ 1.56	$ 1.84	$ 0.62	$ 1.87	$ 1.31	$ 2.05	$ 1.62	$ 1.85	
	2017	$2.20	$ 1.64	$ 1.92	$ 0.70	$ 1.91	$ 1.35	$ 2.20	$ 1.74	$ 1.87	
	2018	$2.30	$ 1.72	$ 2.01	$ 0.74	$ 1.97	$ 1.39	$ 2.34	$ 1.85	$ 1.87	
	2019	$ 60.29	$ 63.97	$ 73.20	$ 30.52	$ 56.53	$ 45.15	$ 34.10	$ 57.02	$ 70.51	
	DCF	8.65%	7.13%	11.43%	7.40%	10.05%	8.28%	15.19%	4.18%	8.24%	This DCF result is an Internal Rate of Return *computation made by the "IRR" function* built into the Microsoft Excel spreadsheet it is based on the actual cash flows shown from 2015 to 2019.
	Average DCF Result		**8.95%**								
	Median DCF Result		**8.28%**								

EXTERNAL FINANCING RATE
(Millions of Shares)

		Common Stock Outstanding 2014	2018-20	Compound Annual
GAS GROUP				
AGL Resources	GAS	119.65	125.00	0.88%
Atmos Energy Corp	ATO	100.39	120.00	3.63%
Laclede Group	LG	43.18	45.00	0.83%
NRG Energy	NRG	336.66	340.00	0.20%
N.W. Nat'l Gas	NWN	27.00	28.00	0.73%
Piedmont Nat'l Gas	PNY	77.88	80.00	0.54%
South Jersey Inds.	SJI	34.00	38.00	2.25%
Southwest Gas	SWX	46.52	52.00	2.25%
WGL Holdings	WGL	51.76	52.00	0.09%
			Average	1.27%
			Median	0.83%
			Round to	**1.00%**

Source: Most Current Value Line

SCHEDULE ALR 6, Page 1

Actual Capital Structure
GAS GROUP

	% Common Equity						Quantity					Percentage			
	2010	2011	2012	2013	2014	*($ millions)* Total Debt	LT Debt	ST Debt	Pfd Stock ($ millions)	Equity	Total Capital	LT Debt	ST Debt	Pfd Stock	Equity Ratio With ST Debt
AGL Resources	52.0%	48.2%	50.6%	48.8%	51.2%	$ 5,754.0	$ 3,602.0	$ 2,152.0	$ -	$ 3,779.1	$ 9,533.1	37.8%	22.6%	0.0%	**39.6%**
Atmos Energy Corp	54.6%	50.6%	54.7%	51.2%	55.7%	$ 3,006.0	$ 2,455.1	$ 550.9	$ -	$ 3,086.9	$ 6,092.9	40.3%	9.0%	0.0%	**50.7%**
Laclede Group	59.5%	61.1%	63.9%	53.4%	44.9%	$ 2,248.5	$ 1,736.3	$ 512.2	$ -	$ 1,414.9	$ 3,663.4	47.4%	14.0%	0.0%	**38.6%**
NRG Energy*					57.3%	$ 20,374.0	$ 19,900.0	$ 474.0	$ 249.0	$ 27,047.6	$ 47,670.6	41.7%	1.0%	0.5%	**56.7%**
N.W. Nat'l Gas	53.9%	52.7%	51.5%	52.4%	52.5%	$ 851.7	$ 621.7	$ 230.0	$ -	$ 687.1	$ 1,538.8	40.4%	14.9%	0.0%	**44.7%**
Piedmont Nat'l Gas	59.0%	59.6%	51.3%	50.3%	47.9%	$ 1,779.4	$ 1,424.4	$ 355.0	$ -	$ 1,309.6	$ 3,089.0	46.1%	11.5%	0.0%	**42.4%**
South Jersey Inds.	62.6%	59.5%	55.0%	54.9%	48.5%	$ 1,158.8	$ 935.4	$ 223.4	$ -	$ *880.9*	$ *2,039.7*	*45.9%*	*11.0%*	*0.0%*	***43.2%***
Southwest Gas	50.9%	56.8%	50.8%	50.6%	47.3%	$ 1,449.0	$ 1,437.7	$ 11.3	$ -	$ 1,290.4	$ 2,739.4	52.5%	0.4%	0.0%	**47.1%**
WGL Holdings	65.0%	66.2%	67.3%	69.8%	63.8%	$ 1,345.6	$ 975.6	$ 370.0	$ 28.2	$ 1,769.1	$ 3,142.9	31.0%	11.8%	0.9%	**56.3%**
	57.2%	**56.8%**	**55.6%**	**53.9%**	**52.1%**	**$ 37,967**	**$ 33,088**	**$ 4,879**	**$ 277**	**$ 41,266**	**$ 79,510**				
											Average	**42.57%**	**10.69%**	**0.16%**	**46.59%**
											Median	**41.74%**	**11.49%**	**0.00%**	**44.65%**

Source: Most Current Value Line

**Value Line does not have a common equity ratio figure for NRG Energy*

Estimated Common equity ratio by dividing the "Shr. Euity" from 2014 by "Total Debt" as of 12/31/14

Note: NRG has 4,450 ($mil) in working capital in 2015 according to Value Line

Actual Capital Structure - Without Short Term Debt
GAS GROUP

	% Common Equity					($ millions)	LT Debt	ST Debt	Pfd Stock	Equity	Total	LT Debt	ST Debt	Pfd Stock	Equity Ratio
	2010	2011	2012	2013	2014	Total Debt			($ millions)		Capital				With ST Debt
AGL Resources	52.0%	48.2%	50.6%	48.8%	51.2%	$ 5,754.0	$ 3,602.0		$ -	$ 3,779.1	$ 7,381.1	48.8%		0.0%	51.2%
Atmos Energy Corp	54.6%	50.6%	54.7%	51.2%	55.7%	$ 3,006.0	$ 2,455.1		$ -	$ 3,086.9	$ 5,542.0	44.3%		0.0%	55.7%
Laclede Group	59.5%	61.1%	63.9%	53.4%	44.9%	$ 2,248.5	$ 1,736.3		$ -	$ 1,414.9	$ 3,151.2	55.1%		0.0%	44.9%
NRG Energy*					57.3%	$ 20,374.0	$ 19,900.0		$ 249.0	$ 27,047.6	$ 47,196.6	42.2%		0.5%	57.3%
N.W. Nat'l Gas	53.9%	52.7%	51.5%	52.4%	52.5%	$ 851.7	$ 621.7		$ -	$ 687.1	$ 1,308.8	47.5%		0.0%	52.5%
Piedmont Nat'l Gas	59.0%	59.6%	51.3%	50.3%	47.9%	$ 1,779.4	$ 1,424.4		$ -	$ 1,309.6	$ 2,734.0	52.1%		0.0%	47.9%
South Jersey Inds.	62.6%	59.5%	55.0%	54.9%	48.5%	$ 1,158.8	$ 935.4		$ -	$ 880.9	$ 1,816.3	51.5%		0.0%	48.5%
Southwest Gas	50.9%	56.8%	50.8%	50.6%	47.3%	$ 1,449.0	$ 1,437.7		$ -	$ 1,290.4	$ 2,728.1	52.7%		0.0%	47.3%
WGL Holdings	65.0%	66.2%	67.3%	69.8%	63.8%	$ 1,345.6	$ 975.6		$ 28.2	$ 1,769.1	$ 2,772.9	35.2%		1.0%	63.8%
	57.2%	**56.8%**	**55.6%**	**53.9%**	**52.1%**	**$ 37,967**	**$ 33,088**	**$ -**	**$ 277**	**$ 41,266**	**$ 74,631**				
											Average	47.71%		0.17%	52.12%
											Median	48.80%		0.00%	51.20%

Source: Most Current Value Line

**Value Line does not have a common equity ratio figure for NRG Energy*

Estimated Common equity ratio by dividing the "Shr. Euity" from 2014 by "Total Debt" as of 12/31/14

Note: NRG has 4,450 ($mill) in working capital in 2015 according to Value Line

Actual Capital Structure
NiSource

	% Common Equity					($ millions)	LT Debt	ST Debt	Pfd Stock	Equity	Total	LT Debt	ST Debt	Pfd Stock	Equity Ratio
	2010	2011	2012	2013	2014	Total Debt			($ millions)		Capital				With ST Debt
NiSource	45.3%	44.4%	44.9%	43.7%	43.1%	$ 9,999.4	$ 8,155.9	$ 1,843.5	$ -	$ 6,177.8	$ 16,177.2	50.4%	11.4%	0.0%	38.2%
	45.3%	**44.4%**	**44.9%**	**43.7%**	**43.1%**	**$ 9,999.4**	**$ 8,156**	**$ 1,844**	**$ -**	**$ 6,178**	**$ 16,177**				
											Average	**50.42%**	**11.40%**	**0.00%**	**38.19%**
											Median	**50.42%**	**11.40%**	**0.00%**	**38.19%**

Source: Most Current Value Line

Actual Capital Structure -<u>Without Short-Term Debt</u>
NISource

	% Common Equity					($ millions)									
	2010	2011	2012	2013	2014	Total Debt	*LT Debt*	*ST Debt*	*Pfd Stock* ($ millions)	*Equity*	*Total* Capital	*LT Debt*	*ST Debt*	*Pfd Stock*	*Equity Ratio* With ST Debt
NiSource	45.3%	44.4%	44.9%	43.7%	43.1%	$ 9,999.4	$ 8,155.9		$ -	$ 6,177.8	$ 14,333.7	56.9%		0.0%	43.1%
	45.3%	**44.4%**	**44.9%**	**43.7%**	**43.1%**	**$ 9,999.4**	**$ 8,156**	**$ -**	**$ -**	**$ 6,178**	**$ 14,334**				
											Average	**56.90%**		**0.00%**	**43.10%**
											Median	**56.90%**		**0.00%**	**43.10%**

Source: Most Current Value Line

SCHEDULE ALR 7

VALUE LINE COMPOUND ANNUAL GROWTH RATES
FROM 2012-2014 TO 2018-2020

		Earnings	Dividend	Book Value	Value Line Source Report Date
GAS GROUP					
AGL Resources	GAS	6.5%	4.5%	5.0%	4/6/2015
Atmos Energy Corp	ATO	7.0%	5.0%	4.5%	4/6/2015
Laclede Group	LG	10.0%	4.5%	7.5%	4/6/2015
NRG Energy*	NRG	18.0%	22.0%	4.5%	4/27/2015
N.W. Nat'l Gas	NWN	5.5%	2.5%	4.0%	4/6/2015
Piedmont Nat'l Gas	PNY	3.0%	3.0%	4.5%	4/6/2015
South Jersey Inds.	SJI	7.5%	7.0%	6.0%	4/6/2015
Southwest Gas	SWX	6.0%	7.5%	3.0%	4/6/2015
WGL Holdings	WGL	4.5%	3.0%	3.5%	4/6/2015
	AVERAGE	**7.56%**	**6.56%**	**4.72%**	

*From 2011-2103 to 2018-2020

VALUE LINE COMPOUND ANNUAL EPS GROWTH RATES
FROM 2014 TO 2016-2018

		EPS 2016	EPS 2018-2020	Compound Annual Growth from 2014 to 2016-2018	Value Line Source Report Date
GAS GROUP					
AGL Resources	GAS	$3.90	$4.65	6.04%	4/6/2015
Atmos Energy Corp	ATO	$3.20	$3.80	5.89%	4/6/2015
Laclede Group	LG	$3.10	$4.20	10.65%	4/6/2015
NRG Energy	NRG	$0.90	$2.00	30.49%	4/27/2015
N.W. Nat'l Gas	NWN	$2.60	$3.30	8.27%	4/6/2015
Piedmont Nat'l Gas	PNY	$2.00	$2.10	1.64%	4/6/2015
South Jersey Inds.	SJI	$3.70	$5.00	10.56%	4/6/2015
Southwest Gas	SWX	$3.50	$4.25	6.69%	4/6/2015
WGL Holdings	WGL	$3.05	$3.20	1.61%	4/6/2015
	AVERAGE			9.09%	

SCHEDULE ALR 8

Gas Group 2014 Revenues - Regulated and Non Regulated

		Regulated	Non Regul	Total	Intercompany
AGL Resources	GAS	$ 3,802	$ 1,667	$ 5,469	$ (84)
Atmos Energy Corp	ATO	3,380	2,067	5,447	(506)
Laclede Group	LG	1,462	164	1,626	-
NRG Energy	NRG	7,376	8,492	15,868	
N.W. Nat'l Gas	NWN	732	22	754	
Piedmont Nat'l Gas	PNY	1,196	275	1,471	-
South Jersey Inds.	SJI	502	425	927	(40)
Southwest Gas	SWX	1,382	740	2,122	
WGL Holdings	WGL	1,417	1,364	2,781	-
Total		$ 21,249	$ 15,216	$ 36,465	

Gas Group 2014 Revenues - Percentage From Regulated and Non Regulated Operations

		Regulated	Non Regulated
AGL Resources	GAS	70%	30%
Atmos Energy Corp	ATO	62%	38%
Laclede Group	LG	90%	10%
NRG Energy	NRG	46%	54%
N.W. Nat'l Gas	NWN	97%	3%
Piedmont Nat'l Gas	PNY	81%	19%
South Jersey Inds.	SJI	54%	46%
Southwest Gas	SWX	65%	35%
WGL Holdings	WGL	51%	49%
Total Gas Group		58%	42%

Source: Company Annual Reports

Appendix A

RESUME OF AARON LLOYD ROTHSCHILD

CONSULTING, EXPERT TESTIMONY, AND FINANCIAL ANALYSIS IN REGULATED UTILITY INDUSTRIES

- Recognized Subject Matter Expert with extensive experience providing financial analysis to technical and legal professionals in regulated industries, including electric, gas, water, and telecommunications
- Specialty provider of "rate of return" testimonies to state governments for utility rate hearings, assisting attorneys on all phases of rate case proceedings, including cross examination and financial modeling
- Represented consumer advocates in multiple jurisdictions; repeatedly reduced utility cost of equity approvals under 10% for first time in decades by applying innovative financial models
- Consumer Advocate role as business development manager for Competitive Local Exchange Carrier (CLEC) during implementation of Telecommunications Act of 1996
- International background includes business development and strategic planning in Asia-Pacific market for MCI during deregulation of telecom incumbents in Japan, Korea, Hong Kong and other countries

PROFESSIONAL EXPERIENCE

Rothschild Financial Consulting, Ridgefield, CT 2001-Present

Consultant

- Provide expert financial testimonies to state governments and consumer advocate groups in support of utility rate regulation
- Collaborate closely with client to prepare cross examination questions
- Prepare interrogatories and analysis reports of opposing witness testimony; write direct and surrebuttal testimony; attend hearings and submit to cross-examinations
- Developed ground-breaking testimony supporting use of consolidated capital structure in 2002 Verizon New Hampshire rate case
- Designing financing mechanism for renewable generation projects that aligns interests of consumers and investors by reducing investment risk and cost of capital (Panelist at NARUC/NASUCA Annual Meeting 2011)

360 Networks, Hong Kong 2001

Senior Manager

- Investment evaluation of $1B Japan-U.S. undersea cable, Intra Asia cable network expansion plans, cable landing stations, and partnership negotiations in Korea, Japan and other markets

Dantis, Chicago, IL 2000

Director

- Raised $100M from venture capital firm through valuation negotiations and internal strategic analysis

MCI, Chicago, Tokyo, Hong Kong 1996-2000

Senior Manager

- Head of Business Development for Japan Operations - $80M national fiber optic network expansion
- Business Development and Strategic Planning manager in U.S. and Hong Kong
- Developed partnerships with Telecommunication Firms in variety of Asia-Pacific markets

EDUCATION

MBA, Finance from Vanderbilt University, 1996 BA, Mathematics from Clark University, 1994

TESTIFYING EXPERIENCE OF AARON L. ROTHSCHILD
THROUGH JUNE 2015

COLORADO

Public Service Company of Colorado; Docket No. 11AL-947E, Rate of Return, March 2012

CONNECTICUT

United Water Connecticut; Docket No. 07-05-44, Rate of Return, November 2008
Valley Water Systems; Docket No. 06-10-07, Rate of Return, May 2007

DELAWARE

Tidewater Utilities, Inc.; PSC Docket No. 11-397, Rate of Return, April 2012
Delmarva Power & Light, PSC Docket No. 09-414, Rate of Return, February 2010
Delmarva Power & Light, PSC Docket No. 09-276T, Rate of Return, February 2010

FLORIDA

Florida Power & Light (FPL); Docket No. 070001-EI, October 1, 2007
Florida Power Corp; Docket No. 060001 Fuel Clause, September 2007

NEW JERSEY

Aqua New Jersey, Inc.; BPU Docket No. WR11120859, Rate of Return, April 2012

MARYLAND

Potomac Electric Power Company; Case No. 9311, Rate of Return, 2013
Delmarva Power & Light; Case No. 9317, Rate of Return, June 2013
Columbia Gas of Maryland; Case No. 9316, Rate of Return, May 2013
Delmarva Power & Light; Case No. 9285, Rate of Return, March 2012
Potomac Electric Power Company; Case No. 9286, Rate of Return, March 2012

NORTH DAKOTA

Northern States Power; Case No. PU-400-04-578, Rate of Return, March 2005

PENNSYLVANIA

Pike County Light & Power Company; Docket No. R-2013-2397237(electric), Rate of Return, April 29, 2014
Pike County Light & Power Company; Docket No. R-2013-2397353 (gas), Rate of Return, April 29, 2014
Columbia Water Company; Docket No. R-2013-2360798, Rate of Return, August 5, 2013
Peoples TWP LLC; Docket No. R-2013-2355886, Rate of Return, July 31, 2013
City of Dubois – Bureau of Water; Docket No. R-2013-2350509, Rate of Return, July 25, 2013
City of Lancaster – Sewer Fund, Docket No. R-2012-2310366, Rate of Return, December 2012
Citizens' Electric Company of Lewisburg, Pa; Docket No. R-2010-2172662, Rate of Return, September 2010
Wellsboro Electric Company; Docket No. R-2010-2172665, Rate of Return, September 2010
York Water Company; Docket No. R-2010-2157140, Rate of Return, August 2010
T.W. Phillips Gas and Oil Company; Docket No. R-2010-2167797, Rate of Return, August 2010
Joint Application of The Peoples Natural Gas Company, Dominion Resources, Inc. and Peoples Hope Gas Company LLC, Docket No. A-2008-2063737, Financial Analysis, December 2008
York Water Company; Docket No. R-2008-2023067, Rate of Return, August 2008

VERMONT

Central Vermont Public Service Corp., Docket No. 7321, Rate of Return, September, 2007

OCA Statement 2-S

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISION

Pennsylvania Public Utility Commission :

:

v. : Docket No. R-2015-2468056

:

Columbia Gas of Pennsylvania, Inc. :

SURREBUTTAL TESTIMONY
OF
AARON L. ROTHSCHILD

ON BEHALF OF
THE OFFICE OF CONSUMER ADVOCATE

RECEIVED
2015 AUG -7 PM 12 14
PA PUC
SECRETARY'S BUREAU

July 28, 2015

OCA Stmt. 2-S
R-2015-2468056
8-4-15
Harrisburg JS

Contents

I. SUMMARY OF MR. MOUL'S COMMENTS

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the following issues addressed in Mr. Moul's Rebuttal Testimony.

1. Capital structure.
2. Discounted cash flow method.
3. DCF growth rate.
4. DSIC adjustment.
5. WNA adjustment.
6. VIX index.

As addressed below, Mr. Moul's criticisms are unsupported and should be rejected.

II. CAPITAL STRUCTURE

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT EXCLUDING SHORT – TERM DEBT IS THE ONLY VALID METHOD FOR COMPARISON TO CONFIRM THE REASONABLENESS OF THE COMPANY'S REQUESTED CAPITAL STRUCTURE.

A. The fact that value line does not directly publish the average short-term debt balance is not an excuse to not attempt to compare the Company's requested capital structure to a barometer group (Gas Group in this proceeding).

Q. WERE YOU ABLE TO CALCULATE THE AVERAGE SHORT-TERM DEBT BALANCE OF THE BAROMETER GROUP (GAS GROUP)?

A. Yes. I was able to calculate the average short-term debt balance of the Gas Group by averaging the spot short-term debt levels for the last four value line publications (as of 03/31/15, 12/31/14, 09/30/14, 06/30/14).

Q. WHAT IS THE AVERAGE SHORT-TERM DEBT RATIO FOR THE GAS GROUP FOR THE PAST FOUR VALUE LINE PUBLICATIONS?

A. 11.1%.[1]

Q. WHAT DOES THIS SHORT-TERM DEBT RATIO OF 11.1% INDICATE REGARDING THE APPROPRIATE CAPITAL STRUCTURE TO USE FOR RATE MAKING PURPOSES FOR COLUMBIA GAS?

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[1] Schedule ALR SR1, page 1

A. This indicates that my recommended capital structure, which includes a short-term debt ratio of 10.69%[2], includes capital structure ratios that are comparable to the Gas Group and is appropriate for rate making purposes. The Company's requested capital structure, with a short-term debt ratio of 5.14%[3] (less than half the Gas Group's short-term debt ratio), is not appropriate for rate making purposes.

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT YOU IMPROPERLY ASSIGNED THE COMPANY'S ACTUAL COST OF LONG-TERM DEBT TO THE LONG-TERM DEBT RATIO IN YOUR RECOMMENDED CAPITAL STRCUTRE?

A. The actual long-term debt ratio used to raise capital for Columbia Gas is NiSource's long-term ratio of over 50%[4]. Mr. Moul is applying the "actual cost of long-term debt" to a 42.65% long-term ratio.

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT COMPARING THE CAPITAL STRUCTURE OF CPA TO ITS PARENT COMPANY, NISOURCE INC., IS NOT VALID?

A. Mr. Moul acknowledges in his direct testimony that Columbia Gas receives its external capital from NiSource[5] and its capital structure ratios impacts CPA's cost of equity[6]. NiSource finances non-regulated operations not included in rate base, but these riskier operations would require a higher common equity ratio, not less, than regulated utilities like Columbia Gas. Regarding the 2000 acquisition of Columbia Energy Group, he mentioned merger debt but he fails to mention the more than $3.6 billion in goodwill on NiSource's books, most of which is from the acquisition of Columbia on November 1, 2000[7]. Since goodwill cannot be included in rate base and it doesn't produce cash flow, it has the effect of increasing what NiSource's common equity ratio would be otherwise.

Further, on page 9 of Mr. Moul's Rebuttal Testimony he points out facts that support using a common equity below NiSource's common equity ratio of 38.18% for rate making purposes in this proceeding.

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[2] Schedule ALR 1

[3] Mr. Moul's Direct testimony, page 2

[4] Schedule ALR 6, page 3

[5] Mr.Moul's Direct Testimony, Page 14, Lines 5-6

[6] Ibid. Schedule 1, page 2 of 2, "Credit Quality"

[7] NiSource 2014 Annual Report, page 38

III. DISCOUNED CASH FLOW

Q. PLEASE RESPOND TO MR. MOUL'S COMMENTS REGARDING THE DCF METHOD AND MARKET-TO-BOOK RATIOS ON PAGES 15-16 OF HIS REBUTTAL TESTIMONY.

A. The cost of capital is market-based, and the price investors are willing to pay for a stock in relation to what they expect to receive in return is the information that is used to determine the cost of equity. For example, if investors are willing to pay more than book value for a utility company with an allowed return of 9%, generally this means that investors require less than a 9% return to be convinced to buy shares of this company. As investors bid up the price of a bond, its yield decreases. As stated on page 41, lines 2-5 of my Direct Testimony, "The DCF model is specifically designed to recognize the difference in the value of earnings paid out as a dividend and retained earnings, a properly applied DCF model maintains its accuracy irrespective of the market-to-book ratio."

IV. DCF GROWTH RATE

Q. ON PAGE 18 OF HIS REBUTTAL TESTIMONY, MR. MOUL CONCLUDES THAT "EARNINGS PER SHARE FORECASTS MUST BE GIVEN GREATEST WEIGHT" REGARDING THE APPROPRIATE GROWTH RATE TO USE IN THE DCF METHOD. HOW DO YOU RESPOND?

A. I disagree. There is a recent study that shows that earnings per share growth is not the best indicator of investor required returns. A study conducted by McKinsey & Company in 2010 found that "analysts have been persistently over optimistic for the past 25 years with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth."[8] Specifically, this study found the following:

> On average, analysts' forecasts have been almost 100 percent too high.
>
> Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999-2001, actual price-to-earnings ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts.[9]

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[8] Marc H. Goedhart, Rishi Raj and Abhishek Saxena, *Equity Analysts: Still too bullish*, Spring 2010.

[9] Ibid.

Even if equity analysts' forecasts are not upwardly biased, as discussed in my Direct Testimony, adding earnings per share growth forecasts to a dividend yield without considering the retention rate produces a flawed result.

V. LEVERAGE ADJUSTMENT

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. No. As stated in on pages 55-58 of my Direct Testimony, Mr. Moul's leverage adjustment goes against original cost rate making and should be rejected.

VI. DSIC ADJUSTMENT

Q. PLEASE RESPOND TO MR. MOUL'S COMMENT THAT YOUR PROPOSAL WOULD INFLUENCE THE RATE OF RETURN ALLOWED ON ALL CLASSES OF PROPERTY?

A. As stated in my Direct Testimony, bond rating agencies view provisions like the DSIC as credit positive for utilities, which reduces their cost of capital.

Q. PLEASE COMMENT ON MR. MOUL'S CLAIM THAT "MR. ROTHSCHILD INCORRECTLY ASSUMES ON AVERAGE 42% OF THE REVENUES OF THE COMPANIES IN THE BAROMETER GROUP ARE UNAFFECTED BY THE EXISTENENCE OF A DSIC."

A. In my Direct Testimony I determined (not assumed) that 42%[10] of the revenues of the companies in the proxy group (i.e., Gas Group) are from non-regulated operations. This equates to 58%, on average, of revenues from regulated operations. I obtained my data from the most recent annual reports for each of the companies in the Gas Group. Mr. Moul does not provide the source of data he used to calculate that 70%[11] of the Gas Group revenues are from regulated operations. I was therefore not able to determine how Mr. Moul calculated that 30% of revenues in the Gas Group are from non-regulated operations.

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[10] Schedule ALR 8

[11] Mr. Moul's Rebuttal testimony, Exhibit PRM-2R, page 8 of 29

VII. WNA ADJUSTMENT

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT NO ADJUSTMENT TO THE COST OF EQUITY IS WARRANTED FOR THE WNA BECAUSE THE RISK ATTRIBUTES OF THE WNA ARE FULLY REFLECTED IN THE COST OF EQUITY DETERMINATION WITH MARKET DATA DERIVED FROM THE GAS GROUP.

A. Mr. Moul states in his Rebuttal Testimony that on pages 8 and 9 of his Direct Testimony (Statement No. 8) he fully documents that no adjustment to the cost of equity is required for the WNA, but he leaves out that the Gas Group has significant non-regulated operations that could not possibly be influenced by a WNA adjustment. In his Rebuttal Testimony, in response to my determination that 42%[12] of the revenues of the companies in the proxy group (i.e., Gas Group) are from non-regulated operations, he addresses this critical data by stating "Mr. Rothschild's assumption is erroneous" and claims to show that it is in fact 30% (70% from regulated operations)[13]. Mr. Moul, however, does not provide the source of data he used to calculate that 70%[14] of the Gas Group revenues are from regulated operations. My calculations (not assumptions) are based on data from the most recent annual reports of the companies in the Gas Group.

VIII. THE VIX INDEX

Q. MR. MOUL COMMENTED THAT THE VIX INDEX HAS INCREASED SINCE YOU FILED YOUR DIRECT TESTIMONY. PLEASE RESPOND.

A. The VIX Index increased in late June and early July during Greece's negotiations with the EU-IMF for debt relief. The VIX Index has since decreased to levels similar to when I filed my Direct Testimony by the middle of July.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REACTION TO MR. MOUL' REBUTTAL TESTIMONY.

A. Mr. Moul's criticisms of my Direct Testimony are unsupported and should be rejected. As explained in my Direct Testimony, my DCF method maintains its accuracy irrespective of the market-to-book ratio of gas utility stocks. Mr. Moul's comparison of projected returns on book equity to DCF results leaves out the most important piece of information in determining the cost of equity which is: what are investors willing to pay for what they expect to receive in the future.

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[12] Schedule ALR 8

[13] Mr. Moul's Direct Testimony, page 41, lines 22-23.

[14] Mr. Moul's Rebuttal testimony, Exhibit PRM-2R, page 8 of 29

Return on book equity is not the cost of equity. Although I use my DCF analysis to determine my cost of equity recommendation, the 'cost of equity in today's financial market' shows that the fear index is down, stocks are expensive and interest rates remain near historic lows. My cost of equity recommendation of 8.88% is market-based and would allow Columbia Gas to raise capital on reasonable terms in to today's capital markets.

Further, as I discussed in my direct testimony, Mr. Moul's recommendation double charges consumers by adding 0.50% to account for "... the lower credit quality of CPA's parent company"[15] while asking consumers to pay for expensive equity (1,402 basis points more than NiSource) of a capital structure that is much lower risk than the capital structure used by NiSource.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

210630

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[15] Mr. Moul's Direct Testimony, page 18, line 18

OCA Statement 2-S

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2468056**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

SCHEDULES ACCOMPANYING THE
SURREBUTTAL TESTIMONY
OF
AARON L. ROTHSCHILD

ON BEHALF OF

THE OFFICE OF CONSUMER ADVOCATE

July 28, 2015

Gas Group Capital Structure Ratios

Average Spot Ratios from 6/30/2014, 9/30/2014, 12/21/2014 and 3/31/2015

	LT Debt	ST Debt	Pfd Stock	Equity
Average	**42.0%**	**11.1%**	**0.2%**	**46.7%**

NiSource Capital Structure Ratios

Average Spot Ratios from 6/30/2014, 9/30/2014, 12/21/2014 and 3/31/2015

	LT Debt	ST Debt	Pfd Stock	Equity
Average	**51.0%**	**8.8%**	**0.0%**	**40.2%**

Gas Group Capital Structure Ratios
As of 3/31/2015

		($ millions)	LT Debt	ST Debt	Pfd Stock	Equity	Total	LT Debt	ST Debt	Pfd Stock	Equity
		Total Debt			($ millions)		Capital				
AGL Resources	GAS	$ 4,711 0	$ 3 524 0	$1,187.0	$ -	$ 4 044	$ 8,755 3	40.2%	13.6%	0.0%	46.2%
Atmos Energy Corp	ATO	$ 2,680 2	$ 2 455 2	$ 225 0	$ -	$ 3,344	$ 6,024.5	40.8%	3.7%	0.0%	55 5%
Laclede Group	LG	$ 2,083 9	$ 1,736 3	$ 327.6	$ -	$ 1,557	$ 3,620 5	48.0%	9.0%	0.0%	43 0%
NRG Energy	NRG	$ 20,515 0	$ 20,050 0	$ 465.0	$ 249 0	$ 11,898	$ 32,661.6	61.4%	1.4%	0.8%	36 4%
N W. Nat'l Gas	NWN	$ 827.9	$ 621 7	$ 206 2	$ -	$ 793	$ 1,621 3	38 3%	12.7%	0.0%	48.9%
Piedmont Nat'l Gas*	PNY	$ 1,904 4	$ 1,424 4	$ 480.0	$ -	$ 1,357	$ 3,261.6	43.7%	14.7%	0.0%	41.6%
South Jersey Inds.	SJI	$ 1,281.8	$ 859 5	$ 422.3	$ -	$ 1,050	$ 2,331 8	36.9%	18.1%	0.0%	45.0%
Southwest Gas	SWX	$ 1,524 8	$ 1 506 8	$ 18 0	$ -	$ 1,651	$ 3,176 0	47.4%	0 6%	0.0%	52.0%
WGL Holdings	WGL	$ 1,170 5	$ 950 5	$ 220 0	$ 28 2	$ 1,215	$ 2,413 7	39 4%	9 1%	1.2%	50.3%
Average								**44.0%**	**9.2%**	**0.2%**	**46.6%**

Value Line: June 5, 2015
*As of 1/31/2015

Gas Group Capital Structure Ratios
As of 12/31/2015

		($ millions)	LT Debt	ST Debt	Pfd Stock	Equity	Total	LT Debt	ST Debt	Pfd Stock	Equity
		Total Debt			($ millions)		Capital				
AGL Resources	GAS	$ 5,754 0	$ 3 602 0	$2,152.0	$ -	$ 3,785	$ 9,538 5	37.8%	22.6%	0.0%	39 7%
Atmos Energy Corp	ATO	$ 3,006 0	$ 2.455 1	$ 550 9	$ -	$ 3,086	$ 6,092.0	40.3%	9.0%	0.0%	50.7%
Laclede Group	LG	$ 2,248 5	$ 1,736 3	$ 512.2	$ -	$ 1,508	$ 3,756 8	46.2%	13.6%	0.0%	40.1%
NRG Energy	NRG	$ 20,374 0	$ 19,900 0	$ 474.0	$ 249 0	$ 12,170	$ 32,793.3	60.7%	1.4%	0.8%	37.1%
N.W. Nat'l Gas	NWN	$ 851.7	$ 621 7	$ 230 0	$ -	$ 772	$ 1,623 9	38.3%	14 2%	0.0%	47.6%
Piedmont Nat'l Gas*	PNY	$ 1,779 4	$ 1 424 4	$ 355.0	$ -	$ 1,307	$ 3,086 4	46.2%	11.5%	0.0%	42.3%
South Jersey Inds	SJI	$ 1,158 8	$ 95 4	$1,063.4	$ -	$ 899	$ 2,058.1	4.6%	51.7%	0 0%	43.7%
Southwest Gas	SWX	$ 1,449 0	$ 1 437 7	$ 11.3	$ -	$ 1,466	$ 2,935.3	49 0%	0.4%	0.0%	50.6%
WGL Holdings	WGL	$ 1,345 6	$ 975 6	$ 370.0	$ 28 2	$ 1,246	$ 2,620 2	37.2%	14.1%	1.1%	47.6%
Average								**40.0%**	**15.4%**	**0.2%**	**44.4%**

Value Line: March 7, 2015
*As of 10/31/2014

Gas Group Capital Structure Ratios
As of 9/30/2015

		($ millions)	LT Debt	ST Debt	Pfd Stock	Equity	Total	LT Debt	ST Debt	Pfd Stock	Equity
		Total Debt			($ millions)		Capital				
AGL Resources	GAS	$ 5,098 0	$ 3 605 0	$1,493.0	$ -	$ 3,828	$ 8,926 0	40.4%	16.7%	0.0%	42.9%
Atmos Energy Corp	ATO	$ 2,455 9	$ 1 955 9	$ 500.0	$ -	$ 3,075	$ 5,531.2	35 4%	9 0%	0.0%	55.6%
Laclede Group	LG	$ 2,138 1	$ 1,851.0	$ 287.1	$ -	$ 1,509	$ 3,646 6	50.8%	7.9%	0.0%	41 4%
NRG Energy	NRG	$ 20,773 0	$ 19,919 0	$ 854 0	$ 249 0	$ 11,713	$ 32,734 6	60.8%	2.6%	0 8%	35.8%
N.W. Nat'l Gas	NWN	$ 851.7	$ 621 7	$ 230.0	$ -	$ 772	$ 1,623.9	38.3%	14.2%	0.0%	47.6%
Piedmont Nat'l Gas*	PNY	$ 1,664 9	$ 1 174.9	$ 490.0	$ -	$ 1 277	$ 2,941.7	39.9%	16.7%	0.0%	43 4%
South Jersey Inds.	SJI	$ 1,158 8	$ 935 4	$ 223 4	$ -	$ 899	$ 2,058 1	45.4%	10.9%	0.0%	43.7%
Southwest Gas	SWX	$ 1,449 0	$ 1 437 7	$ 11 3	$ -	$ 1 499	$ 2,948 3	48.8%	0.4%	0.0%	50.9%
WGL Holdings	WGL	$ 1,152 7	$ 679 2	$ 473.5	$ 28 2	$ 1 322	$ 2,503 4	27.1%	18.9%	1.1%	52.8%
Average								**43.0%**	**10.8%**	**0.2%**	**46.0%**

Value Line: December 5,2014
*As of 7/31/2014

Gas Group Capital Structure Ratios
As of 6/30/2014

		($ millions)	LT Debt	ST Debt	Pfd Stock	Equity	Total	LT Debt	ST Debt	Pfd Stock	Equity
		Total Debt			($ millions)		Capital				
AGL Resources	GAS	$ 4,779 0	$ 3 605 0	$1,174.0	$ -	$ 3,894	$ 8,673.0	41.6%	13.5%	0.0%	44.9%
Atmos Energy Corp	ATO	$ 2,455 9	$ 1 955 9	$ 500 0	$ -	$ 3,181	$ 5,636 7	34.7%	8.9%	0.0%	56 4%
Laclede Group	LG	$ 976 6	$ 976 6	$ -	$ -	$ 1,541	$ 2,517 4	38.8%	0.0%	0.0%	61.2%
NRG Energy	NRG	$ 18,998 0	$ 18,165 0	$ 833.0	$ 249 0	$ 11 081	$ 30,327 8	59.9%	2.7%	0.8%	36.5%
N W. Nat'l Gas	NWN	$ 795.9	$ 621 7	$ 174 2	$ -	$ 772	$ 1,568.1	39.6%	11.1%	0.0%	49.2%
Piedmont Nat'l Gas*	PNY	$ 1,544 9	$ 1,174 9	$ 370.0	$ -	$ 1 277	$ 2,821.7	41.6%	13.1%	0.0%	45.2%
South Jersey Inds	SJI	$ 1,097 1	$ 805 4	$ 291.7	$ -	$ 950	$ 2,046 8	39.3%	14.3%	0.0%	46.4%
Southwest Gas	SWX	$ 1,389 7	$ 1 365 9	$ 23 8	$ -	$ 1 525	$ 2,914 9	46.9%	0.8%	0.0%	52.3%
WGL Holdings	WGL	$ 966 7	$ 599 2	$ 367.5	$ 28 2	$ 1,329	$ 2,323 5	25.8%	15.8%	1.2%	57.2%
Average								**40.9%**	**8.9%**	**0.2%**	**49.9%**

Value Line September 5, 2014
*As of 4/30/2014

As of 3/31/2015

NiSource	NI	$ 8,734.6	$ 7,957.9	$ 776.7	$ -	$ 6,832	$ 15,566.6	51.1%	5.0%	0.0%	43.9%

Value Line: June 5, 2015

As of 12/31/2015

NiSource	NI	$ 9,999.4	$ 8,155.9	$1,843.5	$ -	$ 6,175	$ 16,174.8	50.4%	11.4%	0.0%	38.2%

Value Line: March 7, 2015

As of 9/30/2015

NiSource	NI	$ 9,727.2	$ 8,397.4	$1,329.8	$ -	$ 6,174	$ 15,901.2	52.8%	8.4%	0.0%	38.8%

Value Line: December 5,2014

As of 6/30/2014

NiSource	NI	$ 9,270.7	$ 7,640.6	$1,630.1	$ -	$ 6,174	$ 15,444.7	49.5%	10.6%	0.0%	40.0%

Value Line: September 5, 2014

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Aaron L. Rothschild, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 2-S, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: Aaron L. Rothschild
Aaron L. Rothschild

Consultant Address: Rothschild Financial Consulting
15 Lake Road
Ridgefield, CT 06877

DATED: July 28, 2015

OCA Statement No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2015-2468056
COLUMBIA GAS OF PENNSYLVANIA, INC.	)	

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

RECEIVED
2015 AUG -7 PM 12 15
PA PUC
SECRETARY'S BUREAU

June 19, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

OCA Stmt. 3
R-2015-2468056
8-4-15
Harrisburg

TABLE OF CONTENTS

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. (Exeter). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation (NFGD) as a Management Trainee in the Research and Statistical Services (RSS) Department. I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's (NFG Supply's) rate department where my responsibilities included utility cost-of-service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Purchased Gas Adjustment (PGA) filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD's 1307(f) proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1996, I became a Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost-of-service and rate design analyses, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and evaluation of customer choice natural gas transportation programs. A brief description of my professional background is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON UTILITY RATES IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony on more than 200 occasions in proceedings before the Federal Energy Regulatory Commission (FERC), utility regulatory commissions in Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Montana, Nevada, New Jersey, Ohio, Rhode Island, Texas, and Virginia, as well as before this Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On March 19, 2015, Columbia Gas of Pennsylvania, Inc. (CPA or Company) filed an application with the Commission to increase its distribution base rates by $46.2 million, or 13.4 percent. Exeter was retained by the Pennsylvania Office of Consumer Advocate (OCA) to review the cost-of-service studies and rate design proposals included in CPA's application, as well as the Company's proposals to expand the availability of natural gas service in its service territory. My testimony addresses CPA's allocated cost-of-service (ACOS) studies and rate design and service expansion proposals.

Q. HAVE YOU PREPARED EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes, I have. Schedules JDM-1 through JDM-5 are attached to my direct testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. Based on the results of my review and analysis, I have reached the following conclusions:

- Typical of a natural gas distribution company (NGDC), a significant percentage of CPA's plant, nearly 65 percent, is comprised of transmission and distribution mains.

- CPA is sponsoring ACOS studies in its application using two different methodologies, each at present and proposed rates. Under one method, distribution mains investment is allocated partially based on the number of customers and partially based on design day demands (Customer-Demand Study). Under the second method, distribution mains investment is allocated utilizing the Peak and Average method (Peak & Average Study). CPA's application also includes a third ACOS study which reflects an average of the Customer-Demand and Peak & Average ACOS studies (Average Study). CPA relies on the Average Study to support its proposed revenue distribution among the various customer classes.

- Under each of the Company's ACOS studies, distribution mains investment has been assigned to one of three categories, and the mains investment assigned to each category has been separately allocated to customer class consistent with the selected ACOS methodology (i.e., either the Customer-Demand or Peak & Average method). CPA's assignment of distribution mains to separate categories is unreasonable, and the Company's ACOS studies which rely on the assignment of distribution mains to separate categories should be rejected.

- In addition, the Company's Customer-Demand methodology misallocates distribution mains plant investment and related costs, and this method produces results that do not reasonably reveal an accurate indication of class-allocated cost responsibilities and should be rejected.

- The Peak & Average Study presented by the OCA in this proceeding reflects an allocation of distribution mains investment which is more consistent with established Commission precedent and cost-of-service principles.
- The OCA's Peak & Average Study produces results consistent with the ACOS study recently filed in a base rate proceeding by Columbia Gas of Massachusetts (CMA), which relies on the Proportional Responsibility method to allocate distribution mains investment.
- CPA's proposed revenue distribution, based on its Average Study, is not reasonably allocated among its customer classes.
- The revenue distribution in this proceeding should be guided by the results of the OCA's Peak & Average Study.
- CPA's proposed Residential customer charge is unreasonable and should be rejected.
- CPA proposals designed to expand the availability of natural gas in its service territory should be approved.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Including this introductory section, my testimony is divided into five sections. In the following section, I detail the reasons that support a finding that CPA's Average Study produces an inaccurate indication of the allocated costs of serving the various customer classes. The next section addresses class revenue requirement allocations. The fourth section of my testimony addresses CPA's proposed Residential rate design. The final section of my testimony addresses CPA proposals to expand the availability of natural gas service in its service territory.

II. COST ALLOCATION

Q. BRIEFLY DESCRIBE THE COST-OF-SERVICE STUDIES SUBMITTED BY CPA IN THIS PROCEEDING.

A. CPA submitted average embedded ACOS studies employing two different cost allocation methodologies. These cost allocation methods differ in the approach used to allocate distribution mains investment.

Q. PLEASE IDENTIFY THE CUSTOMER RATE CLASSES INCLUDED IN THE COMPANY'S ACOS STUDIES.

A. *The Company's ACOS studies include five rate classes:*

- Residential Sales Service and Residential Distribution Service (RSS/RDS);
- Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service (SGSS/SCDS/SGDS);
- Small Distribution Service and low volume, Large General Sales Service (SDS/LGSS);
- Large Distribution Service and high volume, Large General Sales Service (LDS/LGSS); and
- Main Line Sales Service and Main Line Distribution Service (MLS/MLDS).

Q. HOW DO THE ACOS STUDIES PREPARED BY CPA DIFFER?

A. In CPA's ACOS studies, the Company first identified and directly assigned the actual inventory of distribution mains for the MLS/MLDS rate class. Next, the Company assigned the remaining mains investment to one of four categories, including the transmission category and three different distribution categories:

- Low Pressure Distribution;

- Regulated Non-Low Pressure Distribution (Regulated Distribution); and
- Remaining Regulated Pressure Distribution.

CPA then prepared ACOS studies utilizing two different methods to allocate the mains investment assigned to each of the three distribution mains categories to rate class (excluding MLS/MLDS). Under both methods, transmission main investment was allocated based on design day demands. Both methods were used to prepare ACOS studies at present and proposed rates.

Under the first method, which I will refer to as the Customer-Demand method, the distribution mains investment assigned to each category is allocated to rate class partially based on the number of customers and partially based on the design day demands of the customers in each rate class that are served by each of the categories of distribution mains. Under the second method, which I will refer to as the Peak & Average method, distribution mains investment is allocated 50 percent based on the design day demands and 50 percent based on annual, or average daily, demands of the customers in each rate class that are served by each of the categories of distribution mains.

Q. BEFORE CONTINUING, PLEASE EXPLAIN HOW CPA DEFINES EACH OF THE FOUR MAINS CATEGORIES.

A. CPA has defined each of the four mains categories as follows:

Transmission Mains – Mains that do not serve any single customer directly, but rather are designed to serve an entire geographic area. These are the lines that are generally of higher pressure and larger diameter, and transport the gas into CPA's distribution network. The cost of these mains is allocated to all customers, except the directly assigned MLS/MLDS customers.

Low Pressure Mains – Mains that have been identified as only servicing low-pressure customers. These mains are downstream of regulator stations and are, themselves, low pressure. Due to their pressure, these mains do not serve any customer types other than low-pressure. The cost of these mains is only allocated to low-pressure customers.

Regulated Non-Low Pressure Mains – Mains that, due to their pressure, can serve all customer types except low-pressure customers. These mains can be either high-pressure, intermediate-pressure, or medium-pressure. The cost of these mains is allocated to all customers except for the customers served by the low-pressure mains and the directly assigned MLS/MLDS customers.

Remaining Regulated Pressure Mains – Mains that are not specifically assigned to one of the three groups identified above. Rather, they are mains that can either: (1) deliver gas to customers requiring high-pressure, intermediate-pressure, or medium-pressure service; or (2) deliver gas into downstream low pressure systems and regulated non-low-pressure systems. The cost of these mains is allocated to all customers, except the directly assigned MLS/MLDS customers.

Q. DO YOU AGREE WITH CPA'S PROPOSED ALLOCATION OF TRANSMISSION MAINS INVESTMENT IN ITS ACOS STUDIES?

A. No, I do not. As subsequently explained, the distribution of the revenue increase authorized in this proceeding should be based on the OCA's Peak & Average ACOS Study. As such, transmission mains should be allocated utilizing the Peak & Average method for the same reasons distribution mains should be allocated utilizing the Peak & Average method. I address why distribution mains should be allocated utilizing the Peak & Average method later in my testimony. However, reflecting this change to the allocation of transmission mains in the OCA's Peak & Average ACOS Study does not have a material impact on the study results.[1] Therefore, I am not challenging CPA's proposed allocation of transmission mains in this proceeding.

Q. DO YOU AGREE WITH CPA'S PROPOSED SEPARATE ASSIGNMENT AND ALLOCATION OF DISTRIBUTION MAINS INVESTMENT INTO THREE SEPARATE CATEGORIES IN EACH OF ITS ACOS STUDIES?

A. No, I do not. CPA's proposed separate assignment and allocation of distribution mains fails to consider the net investment of each distribution mains category.

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[1] A change to the allocation of transmission mains investment under the Peak & Average method results in a change of 0.1 percent to the allocation of total mains investment for the RSS/RDS class.

Q. WHAT ARE THE IMPLICATIONS OF FAILING TO CONSIDER THE NET INVESTMENT OF EACH DISTRIBUTION MAINS CATEGORY?

A. CPA uses the original cost of its distribution mains investment to develop its allocation factors for the three distribution mains categories. The allocation factors developed by CPA assume that all distribution mains of similar size and type (plastic or steel) cost the same per foot, are of the same vintage, and have the same depreciation expense per foot. This fails to recognize that low-pressure mains are generally older, are more fully depreciated, and that the net investment associated with the low-pressure system is likely less than that of the regulated pressure system. This is important because rates in this proceeding will be set based on net investment, not original costs.

Q. DID YOU ATTEMPT TO DETERMINE THE NET INVESTMENT OF EACH DISTRIBUTION MAINS CATEGORY?

A. Yes. In OCA-8-003, CPA was requested to provide the net investment associated with each mains category. The Company indicated that the requested information was not maintained at this detailed level.

Q. WHAT EVIDENCE IS THERE THAT THE LOW-PRESSURE SYSTEM IS OLDER AND MORE FULLY DEPRECIATED THAN THE REGULATED PRESSURE SYSTEM?

A. CPA mains are almost exclusively either plastic or steel (>99.9 percent). The average in-service date of the Company's plastic mains is 1995, and the average in-service date of the Company's steel mains is 1952. Approximately 55 percent of the low-pressure system consists of steel mains and 45 percent is plastic. For the regulated pressure system, approximately 35 percent is steel and 65 percent is plastic. This indicates that the low-pressure system is older and more fully depreciated than the regulated pressure system.

Q. HOW DID CPA DETERMINE THE CUSTOMER COMPONENT OF DISTRIBUTION MAINS INVESTMENT UNDER THE CUSTOMER-DEMAND METHOD?

A. The Company utilized a minimum-sized unit approach to separately determine the customer component of mains investment for each of the three distribution mains categories. More specifically, CPA determined the installed unit cost per foot of distribution main by pipe size for each of the three distribution mains categories. Pipe sizes generally ranged in diameter from 2-inch pipe to 20-inch pipe. Next, using the average cost of 2-inch-sized pipe in each category, the Company multiplied the unit cost of the installed 2-inch-sized pipe by the total number of feet of pipe installed for each category to determine the cost of the minimum system for that category. This was then compared to the total cost of all of that category of pipe on the CPA system to determine the percentage of that category of distribution mains investment that should be considered customer-related. Table 1 summarizes the approach used by the Company and the percentages of distribution mains investment, by category, that were determined to be customer-related and allocated to customer class based on the number of customers served by those distribution mains.

Table 1.
CPA Analysis of Customer Component of Distribution Mains

Category	Unit Cost of 2-Inch-Sized Pipe	Total Feet of Type of Pipe Installed	Cost of Minimum System	Total Cost of Type of Pipe Installed	Percent
(a)	(b)	(c)	(d) = (b) x (c)	(e)	(f) = (d)/(e)
Low Pressure	$8.34	12,114,210	$101,032,511	$217,938,408	46.4%
Regulated Pressure	9.73	22,157,125	215,593,692	379,849,758	56.8
Remaining Regulated Pressure	11.19	5,385,168	60,260,027	160,511,272	37.6
Total	**$9.50**	**39,656,503**	**$376,886,230**	**$758,299,438**	**49.7%**

To further explain CPA's approach, by way of example, the Company determined the cost to install 2-inch low-pressure distribution mains to be $8.34 per foot. This cost was then multiplied by the total number of feet of low-pressure distribution mains installed (12,114,210 feet) to determine the minimum system component cost of low-pressure distribution mains to be $101,032,511. The Company compared the minimum system component of low-pressure distribution mains to the total cost of low-pressure distribution mains ($217,938,408) to claim that 46.4 percent of CPA's low-pressure distribution mains investment was customer-related.

Q. DO YOU AGREE WITH CPA'S CUSTOMER CLASSIFICATION OF DISTRIBUTION MAINS?

A. No. Allocating distribution mains investment on the basis of the number of customers in each class misallocates these costs of providing service. Distribution mains are not sized for the number of customers served from them, but for the loads placed upon them. This is made clear in the following example: Located along one city block are ten Residential customers with a coincident peak demand of one Mcf each. The distribution main running down the street would have to be capable of delivering 10 Mcf at peak. On another city block is only a small plastics factory that exhibits a maximum demand of 10 Mcf. The main for that one customer has to be sized to deliver 10 Mcf when the plastics factory demand peaks. It is clear that the mains investment is driven by the loads placed upon it—not by the number of customers served from it. 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 Mcf. Again, the main that is sized to deliver 10 Mcf is adequate. 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.

Viewed alternatively, what CPA's minimum system analysis purportedly indicates is that the Company incurs a certain amount of minimum costs *per foot* to install each category of distribution mains, regardless of main size. It is this cost that CPA contends is customer-related, and it is this cost that is allocated to customer classes based on the number of customers. This allocation procedure assigns the same quantity of each category of distribution pipe to each customer in each category, and fails to recognize differences in customer density. CPA's minimum system approach assigns 11.6 feet of low-pressure distribution mains to each customer served by that category of pipe, and 83.5 feet of regulated-pressure distribution mains to each customer served by that category of pipe. It is simply unreasonable to believe that each rate class served by CPA required the same length of main extension by distribution mains category in order to be connected to CPA's system. Non-Residential customers are typically located farther apart than Residential customers and, as such, would generally require more main to be connected to the CPA system. Moreover, this disparity in the feet assigned to low-pressure customers and regulated-pressure customers further illustrates the unreasonableness of the Company's distribution mains assignment/customer component allocation approach.

Q. DOES ANY RECOGNIZED AUTHORITY AGREE WITH YOUR CONCLUSION THAT IT IS IMPROPER TO ALLOCATE A PORTION OF THE MAINS DISTRIBUTION SYSTEM ON THE BASIS OF BEING CUSTOMER-RELATED?

A. Yes. Professor James Bonbright, at pages 491 and 492 of his *Principles of Public Utility Rates*, utilizing an example from the electric industry, states:

> But the really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.
>
> What this last-named cost imputation overlooks, of course, is the **very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system**. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the Company's entire service area stays fixed, an increase in number of customers

> does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.
>
> While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. [Emphasis added]

Professor Bonbright clearly agrees that distribution costs, except for those costs that can be definitely earmarked to benefit specific customers, are not properly classified as customer costs.

Q. HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE ALLOCATION OF DISTRIBUTION MAINS INVESTMENT BASED ON THE NUMBER OF CUSTOMERS?

A. Yes. In Philadelphia Gas Works, Docket No. R-00061931, 2007 Pa. PUC Lexis 46 (2007), the Commission found that mains allocations based on the number of customers are not acceptable.

Q. WOULD AN NGDC LIKE CPA ALWAYS INVEST IN DISTRIBUTION MAINS TO ATTACH A NEW CUSTOMER TO ITS SYSTEM?

A. No. At times, no incremental distribution mains investment is required to extend service to a new customer. In addition, at other times, CPA makes distribution mains investment for purposes other than to connect new customers. For example, CPA has, and expects to make, significant distribution mains investment to replace existing mains. In fact, since 2003, CPA has invested over $633 million in distribution mains, which represents an increase of 170 percent of its total original investment, but the number of customers served has only increased approximately 5 percent.

Q. CAN THE DEMANDS OF RESIDENTIAL CUSTOMERS BE SERVED FROM CPA'S CUSTOMER COMPONENT OF DISTRIBUTION MAINS?

A. Yes. CPA's minimum system consists of 2-inch mains. It is common for many Residential customers to be provided with all of their gas service requirements from a 2-inch main.

Q. IN CPA'S CUSTOMER-DEMAND STUDIES, DID THE COMPANY PROPERLY CONSIDER CUSTOMER DEMANDS THAT CAN BE MET FROM 2-INCH MAINS WHEN IT DETERMINED ITS ALLOCATION OF THE DEMAND-RELATED PORTION OF DISTRIBUTION MAINS COSTS?

A. No. For example, all (or nearly all) Residential customers could be provided service through 2-inch mains. This being the case, there would be little to no unmet Residential gas service requirements that would be dependent upon demand-related pipe costs. However, Residential customers are still allocated nearly 50 percent of non-customer, demand-related distribution mains costs in the Company's Customer-Demand ACOS studies. Clearly, under the Customer-Demand Study, Residential customers should be given credit for their demands that can be met with the so-called minimum system when it comes to determining who is responsible for the remaining portion of distribution mains classified as demand-related. In performing its Customer-Demand ACOS studies, CPA has failed to consider any Residential demand crediting when determining Residential demands that are responsible for, or cause, costs classified as being demand-related. Failing to provide a demand credit results in a double allocation of costs to Residential customers. This issue was addressed by George J. Sterzinger in his article, "The Customer Charge and Problems of Double Allocation of Costs" published in the July 2, 1981 edition of *Public Utilities Fortnightly*.

Q. WHAT DO YOU CONCLUDE REGARDING CPA'S ALLOCATION OF 50 PERCENT OF ITS DISTRIBUTION MAINS COST ON A CUSTOMER-RELATED BASIS IN ITS CUSTOMER-DEMAND ACOS STUDIES?

A. First, I conclude that it is incorrect to consider distribution mains as being customer-related. This is so because mains investment is undertaken when annual gas consumption is high enough to warrant the investment, and mains are sized to meet expected demand levels, independent of the number of customers. In addition, CPA's allocation of 50 percent of its distribution mains cost on the basis of number of customers, combined with its failure to consider the demands that can be met with that investment when it allocates the remainder of its mains costs on a demand basis, is improper.

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. Therefore, CPA's Customer-Demand method should be given zero weight by the Commission.

Q. WOULD IT BE REASONABLE TO ALLOCATE DISTRIBUTION MAINS INVESTMENT BASED SOLELY ON DESIGN PEAK DAY DEMANDS, AS CPA HAS DONE FOR A PORTION OF DISTRIBUTION MAINS INVESTMENT IN ITS CUSTOMER-DEMAND ACOS STUDIES?

A. No. The design day demands utilized in CPA's Customer-Demand ACOS studies are based on a day with a 1-in-15 probability of occurrence. If an allocation of the Company's distribution mains costs on the basis of design peak demands was in accordance with the principle of cost-causality,[2] then demands for natural gas deliveries only under design peak day weather conditions would have to be the only cause for the existence and customer utilization of CPA's distribution mains for gas delivery service. Design peak day demands represent the maximum demands that are expected under the most severe weather assumptions used for planning purposes. While a portion of CPA's distribution mains costs are associated with, and hence should be, allocated on design peak demands, it is obviously wrong to profess that most distribution mains costs are caused by consumer demands on the coldest day experienced in CPA's service territory every 15 years or so. Quite simply, if CPA's customers had a demand for gas only on days that occur every 15 years, there would not be a CPA gas distribution system. The costs of delivered gas supplies on that one design peak day would be prohibitively high, and the cost of delivering gas through CPA's distribution system on that one day simply could not compete with alternative energy costs. For example, CPA's claimed annual cost of providing service is approximately $350 million and its projected design day demands are 791,995 Mcf. This implies a cost of $490 to meet design day demands. If a design day occurred only once every 15 years, this would imply a cost of $6,600 to meet demands on that single day.

Q. IF LOCAL GAS DISTRIBUTION SYSTEMS ARE NOT BUILT TO MEET THE COLDEST DAY WHICH MAY BE EXPERIENCED EVERY 15 YEARS, WHY DO NGDCs INCUR DISTRIBUTION MAINS INVESTMENT COSTS?

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[2] The principle of cost-causality requires costs to be allocated to customers on the basis of the customers' relative use of the service units that gave rise to the costs in the first place.

A. The basic reason why NGDCs like CPA invest in their distribution systems is to meet the annual demands for gas by end-use customers. This is the reason for the existence of the NGDC in the first place. Without sufficient annual gas usage over which to amortize the annual costs of providing service, there would be no gas distribution system. Additionally, as I will describe later, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design day demands in excess of annual demands. Because distribution mains exist and are related to both annual demands and peak demands, both annual and peak demands must be recognized in the allocation of distribution mains costs if the allocation is to be in accordance with the principle of cost causality.

Q. DOES CPA'S MAINS EXTENSION POLICY CONSIDER DESIGN PEAK DEMANDS IN THE COMPANY'S DECISION-MAKING PROCESS?

A. No. The net present value (NPV) of base rate revenues are considered in CPA's mains extension decision-making process. The Company's base rate revenues are primarily collected on a volumetric basis. This policy is described in Section 8.2 of the Company's tariff. Without sufficient annual demands, CPA has no responsibility to extend its system to potential customers, and would not incur the costs to meet customer demands for gas only on one day. CPA may require a contribution-in-aid-of-construction (CIAC) if the NPV of an extension is less than zero.

Q. WHY IS IT PROPER TO ALLOCATE DISTRIBUTION MAINS INVESTMENT ON THE BASIS OF ANNUAL AS WELL AS PEAK DEMANDS?

A. The allocation of mains investment costs on the basis of both annual and peak demands is in accordance with the principle of allocating costs on the basis of cost causality. Natural gas is of little to no value to the customer if that gas cannot be delivered to the location of the gas-burning equipment. CPA's distribution system imparts locational value to the natural gas delivered across that system by allowing for the movement of that gas from its acquisition source to each customer's location. CPA's distribution system exists, and related costs are incurred, to deliver gas to its customers whenever, over the course of each year, its customers demand gas. In other words, CPA's system was built and costs were incurred to deliver gas; both at the time of peak system demand and generally throughout the year. 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.

Q. PLEASE EXPLAIN YOUR STATEMENT THAT COSTS ARE INCURRED TO DELIVER BOTH ANNUAL AND PEAK VOLUMES ACROSS CPA'S SYSTEM.

A. The customers included in CPA's ACOS studies, excluding MLS/MLDS customers, are projected to move approximately 81,800,000 Mcf across CPA's system during the fully forecasted future test period. This equates to an average demand of about 224,110 Mcf each day. CPA's design demand is about 792,000 Mcf. CPA cannot meet its customers' annual gas demands with a system capability any smaller than 224,110 Mcf. In other words, if there were no variance in the daily demands on CPA's system, the capacity of that system would have to be designed to accommodate the daily movement of 224,110 Mcf just to meet the annual demands. To meet peak demands, CPA's system capacity must be 3.5 times larger than 224,110 Mcf. Thus, some costs are related to the average deliveries each day on the CPA system, and some costs are related to the movement of gas when demands are above the average demand.

Rational investment decision analysis requires the consideration of annual volumes delivered across an NGDC's system. A gas distribution system would not exist if all demand-related costs were the responsibility of design peak demands. Customers would simply choose other energy alternatives. A viable gas market is dependent upon the ability to amortize delivery costs over a sufficient volume of service so as to result in a unit cost that can be recovered at a price at which gas can be sold and still compete with other energy sources. The association of costs with annual as well as peak demands, and the allocation of costs on the basis of both annual and peak demands for gas, are absolutely essential to the economic feasibility of a gas delivery system. To largely ignore annual demands and allocate total mains costs on peak demands would be inconsistent with the consideration of annual demands which are absolutely essential to the economic justification of the very costs being allocated.

Q. HOW DO THE COSTS OF PROVIDING FOR THE MOVEMENT OF GAS TO MEET DESIGN PEAK DEMANDS COMPARE TO THE COSTS OF PROVIDING FOR THE MOVEMENT OF GAS TO MEET LESSER DEMANDS?

A. Many of the costs associated with the distribution delivery system do not depend upon pipe sizes. These costs would include planning, surveying, excavation, hauling, pipe bed preparation, unloading and stringing of pipe, municipal inspection, backfill, and pavement and sidewalk replacement. Since a portion of total costs does not vary with pipe size, or are fixed costs, total costs do not increase at a 1-to-1 ratio with increases in maximum demands. The additional costs associated with meeting elevated demands are largely related to the cost of the pipe itself.

Moreover, throughput capability increases not at a 1-to-1 ratio with the size of the pipe, but at a rate equal to the square of pipe diameter. Doubling the diameter of a pipe, for example, increases its capacity by four times the original capacity. Thus, the additional costs of providing additional capacity are lower than the average costs of providing capacity. This means that the costs associated with providing capacity for the movement of average demands are greater on a unit basis than are the costs associated with providing capacity for additional demands. CPA's distribution system exists to deliver annual system requirements. There are costs that are uniquely associated with meeting peak demands, and as such, peak demands should bear some cost responsibility.

Q. ARE GAS FLOWS DURING THE DESIGN PEAK SO IMPORTANT THAT MOST OF CPA'S TOTAL DISTRIBUTION SYSTEM COSTS ARE DIRECTLY RELATED TO, AND CAUSED BY, PEAK DAY DEMAND REQUIREMENTS?

A. No. Peak demands are not the major cause of CPA's demand-related mains cost, and it would be wrong to allocate distribution mains-related costs largely on the basis of peak demands. Only the marginal costs incurred to meet peak demands above other demands are caused by, or directly related to, peak requirements. CPA's gas delivery system simply would not be viable and simply would not exist if the only demand for gas was the demand associated with extreme weather conditions. CPA's delivery system exists because the total annual demand for gas is sufficient to warrant its existence. Because CPA's system exists to deliver annual gas requirements, but some additional costs are related to the delivery of gas during periods of elevated demand, it is appropriate to allocate its distribution mains costs on both annual and peak demands. The allocation of distribution system-related costs only on the basis of peak demands misallocates substantial costs.

Q. TO WHAT EXTENT DO THE COSTS OF MEETING PEAK GAS FLOW REQUIREMENTS EXCEED THE COSTS OF MEETING AVERAGE GAS FLOW REQUIREMENTS?

A. As noted, CPA's design peak day peak demand is about 3.5 times its average demand. A pipe's cross-sectional area, and correspondingly its capacity, varies with the square of its radius. Therefore, doubling the size of a pipe's radius (or diameter) increases the capacity of the pipe four-fold. For example, doubling the diameter of a 2-inch pipe to 4 inches increases the capacity by four times the capacity of the 2-inch pipe. Increasing the diameter of a 2-inch pipe to 8 inches increases the capacity by 16 times. The costs of meeting increased flow requirements that are caused by, or associated with, elevated demands is answered by the relationship of the change in total capacity costs to the change in capacity.

I explained earlier that since many capacity costs are essentially fixed, the increased costs associated with meeting increased capacity requirements is expected to be small. Indeed, it is largely these economies of scale that lead to falling average costs of service and the provision of gas distribution service more economically by one monopoly provider, like CPA, rather than by many competing providers.

Q. DO YOU HAVE CPA-SPECIFIC DATA IDENTIFYING THE COSTS ASSOCIATED WITH MEETING INCREASED CAPACITY REQUIREMENTS?

A. Yes. The most common category of distribution mains installed by CPA is regulated-pressure mains, and the most common type of this category of distribution mains is plastic. In the minimum system analysis prepared by CPA, provided in the response to OCA-1-003, the Company determined the per-foot cost to install plastic regulated-pressure distribution mains. Those costs are reflected in Table 2 for those pipe sizes with a total investment in excess of $25 million.

Table 2.
CPA Cost of Installed Regulated Pressure Mains

Diameter (inches)	Average Cost (per foot)
2	$12.75
4	$37.40
6	$60.29
8	$89.24

As shown on Table 2, the average cost of installing a 2-inch main was approximately $13 per foot, while the average cost of installing a 4-inch main was approximately $37 per foot. Thus, for a four-fold increase in capacity, CPA's total average costs increased by 185 percent (($37 - $13) / $13). Based on this example, a doubling of the pipe size (and hence a quadrupling of capacity) increased capacity costs by 185 percent, indicating that increased demands above average demands can be accommodated at increased distribution mains costs that are 46 percent (185 percent / four-fold increase in capacity) of the costs of meeting average demands:

Cost per Foot				Capacity Increase	Cost of Peak
2-inch	4-inch	Increase	Percent		
(a)	(b)	(c) = (b)-(a)	(d) = (c)/(a)	(e)	(f) = (d)/(e)
$13.00	$37.00	$24.00	185%	4	46%

Table 2 indicates that the average cost of installing an 8-inch main was approximately $90 per foot. Thus, for a 16-fold increase in capacity, CPA's total average costs increased by 600 percent (($90 - $13) / $13) over the cost of a 2-inch pipe. Based on this example, a quadrupling of pipe size (and hence a 16-fold increase in capacity) increased capacity costs by about 600 percent, indicating that increased demands above average demands can be accommodated at an increased distribution mains costs that are 40 percent (600 percent / 16-fold increase in capacity) of the costs of meeting average demands:

Cost per Foot				**Capacity Increase**	**Cost of Peak**
2-inch	**8-inch**	**Increase**	**Percent**		
(a)	(b)	(c) = (b)-(a)	(d) = (c)/(a)	(e)	(f) = (d)/(e)
$13.00	$90.00	$77.00	600%	16	37.5%

Given these two CPA-specific examples above, less than half of distribution mains costs are associated with meeting elevated peak demand requirements and could be allocated based on peak demands, and the remainder is related to customers' annual demands for natural gas and could be allocated on average demands.

Q. HOW CAN DISTRIBUTION MAINS INVESTMENT COSTS BE PROPERLY ALLOCATED?

A. The additional costs of providing capacity in order to meet peak demands, as opposed to lesser demands, should be allocated on a peak demand basis. As I just demonstrated, less than half of CPA's distribution mains costs are associated with meeting increased demands; hence, a portion of mains costs should be allocated on the basis of peak demands. I recommend that 50 percent of CPA's distribution mains system costs, instead of a lesser amount, be allocated on the basis of peak demands. The remaining 50 percent of CPA's distribution mains costs, being related to, or caused by, CPA's annual gas requirements, should be allocated on annual, or average, demands.

Q. HAS THIS COMMISSION PREVIOUSLY APPROVED THE USE OF THE PEAK & AVERAGE METHOD?

A. Yes. The Commission has previously accepted the fact that distribution mains are built on the basis of year-round demands as well as peak demands. In NFGD's 1994 base rate proceeding, the Commission accepted the Peak & Average methodology, stating, "The Peak & Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact." *Pa. P.U.C. v. National Fuel Gas Distribution Co.*, 83 Pa. PUC 262, 360 (1994). See also *Pa. P.U.C. v. National Fuel Gas Distribution Co.*, 73 Pa. PUC 552 (1990); *Pa. P.U.C. v. Equitable Gas Co.*, 73 Pa. PUC 301 (1990); *Pa. P.U.C. v. National Fuel Gas Distribution Corp.* 72 Pa. PUC 1 (1989); and *Pa. P.U.C. v. CPA Gas Co.*, 69 Pa. PUC 138 (1989).

Q. HAVE OTHER COMMISSIONS ACCEPTED THE USE OF THE PEAK & AVERAGE METHOD?

A. Yes. The Indiana Utility Regulatory Commission (IURC) has strongly endorsed the use of the Peak & Average methodology. See *In re Citizens Gas & Coke Utility*, IURC Cause No. 42767 (Oct. 19, 2006). The IURC found that the Peak & Average method was the "equitable and realistic" method for allocating distribution mains costs, and provided the following analysis:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding.
>
> While we do not doubt that distribution mains must be constructed with peak demand in mind, distribution mains do not only serve customers on peak demand days. Therefore, a measure of the costs of distribution mains

> must be allocated to customers based on their usage that takes place on non-peak days. For example, a customer that does not take service at all on the peak demand day-and therefore contributes nothing to peak demand requirements of distribution mains-but receives service through distribution mains at other times should be responsible for some portion of distribution main costs.
>
> The OUCC's approach is much more equitable and realistic. Rather than allocating distribution main costs exclusively based on either peak demand day or average annual consumption, the OUCC used a compromise approach that allocated these costs based on both. Under the OUCC's cost-of-service study, 80% of distribution main costs are allocated based on average demand. (Public's Ex. No. 6 at 13.) In this way, the OUCC's approach allocates part of distribution main costs to customers who receive service through distribution mains throughout the year but who may not receive much or any service on the peak demand day.
>
> For the reasons set forth above, we find the OUCC's cost-of-service study most accurately reflects the manner in which distribution main costs are actually incurred. See, In Re Citizens Gas & Coke Utility, IURC Cause No. 39066, at 31 (Nov. 1, 1999). We therefore adopt the OUCC's cost-of-service study to implement the rates increase approved in this Cause.
>
> [*In re Citizens Gas & Coke Utility*, IURC Cause No. 42767, at 74-75 (Oct. 19, 2006)]

The Illinois Commerce Commission (ICC) has accepted the Peak & Average method for allocating transmission and distribution costs in the natural gas industry. The ICC explained the reasoning behind utilizing a Peak & Average methodology in their decision as follows:

> Generally, [Central Illinois Public Service Company or CIPS] and [Union Electric Company or UE] gas transmission and distribution facilities exist because there is a daily need for such facilities. Regardless of when CIPS and UE experience their respective peak and the level of the peak, customers depend on the continued operation of the Ameren gas transmission and distribution systems to

> meet their daily needs. On the day that the peak does occur. Ameren's own Mr. Carls testifies that CIPS' and UE's respective systems are built to accommodate the system peak without regard to each class' peak. In light of the nature in which the transmission and distribution systems are used and because of the relatively declining cost of increasing capacity, peak demand is not the appropriate emphasis in allocating demand costs...As the Commission concluded in Docket 94-0040, a utility can not justify its transmission and distribution investment on demands for a single day. The allocation method that properly weights peak demand is the [Average & Peak or A&P] method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.
>
> [*Central Ill. Pub. Service Co. Proposed General Increase in Natural Gas Rates, et al.*, 2003 Ill. PUC Lexis 824, 231-232 (2003)]

Finally, the Arkansas Public Service Commission (APSC) accepted the use of the Peak & Average method for allocating gas transmission and distribution plant, stating, "The average and peak method is one of the methods accepted by regulators for allocating demand costs." *In the Matter of the Applications of Ark. Western Gas Co. for Approval of a General Rate Change in Rates and Tariffs*, Docket No. 02-227-U; Order No. 17, 2003 Ark. PUC LEXIS 397,69 (2003).

Q. DOES THE COMPANY'S ACOS PEAK & AVERAGE STUDY REFLECT A REASONABLE ALLOCATION OF DISTRIBUTION MAINS INVESTMENT?

A. No, it does not. As indicated previously, in CPA's Peak & Average ACOS Study, distribution mains investment is separately assigned to one of three categories and each category is separately allocated to each rate class. As previously explained, this assignment is unreasonable. In addition, the Company has not appropriately assigned the costs associated with the Major Account Representatives that manage large Industrial and Commercial customer accounts.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S PEAK & AVERAGE COST-OF-SERVICE STUDY?

A. Table 3 below shows the results of CPA's Peak & Average Study at present rates.

Table 3.
Class Rates of Return
CPA Peak & Average Cost-of-Service Study Results
at Present Rates

Class	Rate of Return	Index
RSS/RDS	6.584%	1.09
SGSS/SCDS/SGDS	6.686	1.10
SDS/LGSS	4.814	0.79
LDS/LGSS	1.261	0.21
MLDS	219.470	36.21
Overall	**6.061%**	**1.00**

Q. HAVE YOU PREPARED A PEAK & AVERAGE ACOS STUDY THAT ELIMINATES THE SEPARATE ASSIGNMENT OF DISTRIBUTION MAINS TO CATEGORIES AND APPROPRIATELY ASSIGNS THE COSTS ASSOCIATED WITH MAJOR ACCOUNT REPRESENTATIVES?

A. Yes. Schedule JDM-1 present the results of a Peak & Average ACOS Study that eliminates the separate assignment of distribution mains to categories and assigns the costs associated with Major Account Representatives to the appropriate classes. This study provides a reasonable indication of the cost of service for each rate class. Table 4 provides a summary of the OCA's Peak & Average Study at present rates.

Table 4.
Class Rates of Return
OCA Peak & Average Cost-of-Service Study Results at Present Rates

Class	Rate of Return	Index
RSS/RDS	7.193%	1.19
SGSS/SCDS/SGDS	6.715	1.11
SDS/LGSS	3.754	0.62
LDS/LGSS	-0.317	-0.05
MLDS	210.935	34.80
Overall	**6.061%**	**1.00**

Q. CPA PRESENTED ACOS STUDIES USING TWO DIFFERENT ALLOCATION METHODS FOR MAINS INVESTMENT. ARE YOU PRESENTING AN ACOS STUDY IN THIS PROCEEDING USING AN ALLOCATION METHOD FOR DISTRIBUTION MAINS INVESTMENT OTHER THAN THE PEAK & AVERAGE METHOD?

A. Yes. In addition to presenting an ACOS study using the Peak & Average method at present rates, I am presenting an ACOS study allocating mains investment using the Proportional Responsibility (PR) method. I am presenting this additional study to support the reasonableness of the results of the ACOS study prepared using the Peak & Average method. I would note that the ACOS study presented by Columbia Gas of Massachusetts (CMA), CPA's affiliate, in its current base rate proceeding before the Massachusetts Department of Public Utilities (D.P.U.), utilized the PR method. (D.P.U. 15-50).

Q. DID CMA PRESENT ACOS STUDIES THAT WERE PREPARED USING A METHOD OTHER THAN THE PR METHOD IN D.P.U. 15-50?

A. No, it did not. CMA's witness in D.P.U. 15-50, Mr. Mark P. Balmert, claims that the PR has become D.P.U. precedent on cost allocation.

Q. PLEASE DESCRIBE THE PR METHOD.

A. Under the PR method, distribution mains investment is allocated to customer class on the basis of PR allocators. The PR method recognizes that capacity on the distribution system has some value each month throughout the year, although that value is diminished in the summer months when demands are much lower. The PR method was developed by Gary H. Grainer of the Wisconsin Public Service Commission.

Q. PLEASE EXPLAIN HOW THE PR ALLOCATORS ARE DEVELOPED.

A. Schedule JDM-2 presents a calculation of PR allocators for the assignment of distribution mains costs to CPA's rate classes using the method presented by CMA in D.P.U. 15-50. First, shown on Schedule JDM-2, normalized distribution sales volumes by month and by class are adjusted by the applicable fuel retention charge to develop normalized monthly sendout volumes by class and for the Company in total. Total sendout volumes by month are then ranked from highest to lowest (Column 2), and a percentage of each month's sendout compared to the peak month's sendout is calculated (Column 3).

For example, as shown on Schedule JDM-2, Column (2), February is CPA's peak month, and February sendout is 100.0000 percent of peak month sendout (Column 3) while May sendout is 37.1868 percent of peak month sendout (Column 3). In the next step (Column 4), the next lowest rank month is identified, and the percent of peak for the next ranked month (Column 5) is subtracted from each month's percent of peak (Column 3) to determine the incremental increase in each monthly percentage peak, which is shown in Column 6. For example, from the percent of peak for May which is the 7th highest ranked month, the percent of peak for October which is the 8th ranked month, is subtracted. The difference between the percent of peak of the current month and the next ranked month is then divided by the rank of the current month.

Using May as an example again, the difference between May's percent of peak and the next month's 8.9917 percent of peak divided by May's percent of peak ranking of 7 to arrive at an individual monthly weighting (Column 7). Cumulative total Company weightings for each month are then determined (Column 9). These weights are determined by starting at the lowest individual weighted month, which using CPA data is September at 1.8697 percent, and adding to the second lowest individual weighted month, the previous month's weighted average, which is on Schedule JDM-2, is August. Therefore, under the PR method, sendout in August would be weighted based on the individual weightings of September and August, and eventually February, the highest ranked month's weighting would be based on the cumulative weighting of all months. Thus, under the PR method, each higher ranked month is assigned a successively higher percentage allocation. The cumulative weighting for each month is then multiplied by each class' share of monthly sendout to develop individual class PR allocations (Column 10).

Q. HAVE YOU PREPARED AN ACOS STUDY USING THE PR METHOD?

A. Yes. Schedule JDM-3 presents the results of the PR study at present rates. Table 5 presents a summary of the PR study at present rates.

Table 5. CPA Class Rates of Return Proportional Responsibility Cost-of-Service Study at Present Rates		
Class	**Rate of Return**	**Index**
RSS/RDS	7.852%	1.30
SGSS/SCDS/SGDS	7.029	1.16
SDS/LGSS	3.750	0.62
LDS/LGSS	-1.581	-0.26
MLDS	210.935	34.80
Overall	**6.061%**	**1.00**

A comparison of Tables 4 and 5 reveals that the Peak & Average and PR methods produce very similar cost-of-service results.

III. CLASS REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE HOW CPA IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.

A. CPA generally sought to allocate the revenue increase toward the cost of service indicated by the results of its Average ACOS Study. The Company's proposed base rate revenue distribution is presented in Table 6. It should be noted that the CPA proposed amounts in Table 6 reflect the effect of the Company's proposed Customer Choice (CC), Choice Administrative Charge (CAC), Gas Procurement Charge (GPC), and Merchant Function Charge (MFC) riders.

Table 6.
CPA Proposed Revenue Distribution
($000)

Class	Present Rates	Proposed Rates	Increase	Percent
RSS/RDS	$221,762	$257,571	$35,810	16.1%
SGSS/SCDS/SGDS	57,705	63,843	6,138	10.6
SDS/LGSS	14,052	15,816	1,763	12.5
LDS/LGSS	15,770	18,152	2,382	15.1
MLDS	1,465	1,464	(1)	0.0
Total	**$310,754**	**$356,846**	**$46,902**	**14.8%**

Q. IS CPA'S PROPOSED REVENUE ALLOCATION REASONABLE?

A. No. CPA's revenue allocation is guided by the results of its Average Study. As explained in the prior section of my testimony, this study violates the principle of allocating costs on the basis of cost causality, and does not reasonably reflect the costs of providing service to the various customer classes. The OCA's Peak & Average Study should be used as a guide for the allocation of any increase authorized by the Commission in this proceeding.

Q. WHAT ARE SOME OF THE PRINCIPLES OF A SOUND REVENUE ALLOCATION?

A. A sound revenue allocation should:

- Utilize class cost-of-service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers or the utility (gradualism);
- Yield the total revenue requirement;
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability, and feasibility of application; and
- Reflect fairness in the apportionment of the total cost of service among the various customer classes.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE ALLOCATION OF CPA'S PROPOSED REVENUE INCREASE?

A. Table 7 below summarizes my recommended revenue distribution at proposed rates for the Company's claimed revenue deficiency. This distribution is developed on Schedule JDM-4.

Table 7.
OCA Proposed Revenue Distribution
($000)

Class	Proposed Rates	Increase	Percent
RSS/RDS	$252,415	$30,653	13.82%
SGSS/SCDS/SGDS	66,487	8,782	15.22
SDS/LGSS	17,654	3,601	25.63
LDS/LGSS	18,826	3,056	19.38
MLDS	1,464	(1)	(0.04)
Total	**$356,846**	**$46,092**	**14.8%**

Q. HOW DID YOU DEVELOP YOUR PROPOSED REVENUE DISTRIBUTION?

A. First, because the revenues currently being collected from the MLDS class significantly exceed the indicated cost of service, consistent with CPA's proposal, I assigned no increase to the MLDS class. I increased rates to the SDS/LGSS class to move this class approximately 50 percent toward the indicated cost of service because revenues currently being collected from the LDS/LGSS class are significantly less than the indicated cost of service. I assigned a rate increase to the LDS/LGSS consistent with the percentage increase I assigned to the SDS/LGSS class, with an adjustment to account for negotiated discounted rate (flex) customers. The remaining increase was assigned to the RSS/RDS and SGSS/SCDS/SGDS classes by reducing the current unitized rate of return at present rates toward unity by comparable percentages.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE SCALE-BACK OF YOUR PROPOSED REVENUE DISTRIBUTION TO REFLECT THE INCREASE ACTUALLY AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. In the event that CPA's authorized increase is less than its requested increase, I recommend a proportionate scale-back of the increase for each rate class.

IV. RATE DESIGN

Q. PLEASE DESCRIBE CPA'S CURRENT AND PROPOSED RESIDENTIAL RATES.

A. CPA's current Residential sales and transportation customer distribution rates consist of a $16.75-per-month customer charge and a single delivery charge of $4.2138 for each Mcf of gas delivered. CPA's proposed Residential rate would consist of a $20.60-per-month customer charge and a $4.7354-per-Mcf delivery charge. CPA justifies its proposed Residential customer charge as being within a calculated customer cost range of $18.15 to $35.90. The $18.15 charge is based on CPA's Peak & Average Study, while the $35.90 charge is based on CPA's Customer-Demand Study.

Q. DO YOU HAVE ANY INITIAL COMMENTS CONCERNING CPA'S PROPOSED RESIDENTIAL CUSTOMER CHARGE?

A. Yes. I would like to bring to the Commission's attention the fact that in 2010, CPA's Residential customer charge was $11.50 per month. Since that time, this unavoidable fixed monthly customer charge has increased by 46 percent to the current level of

$16.75 per month. The Company's proposed increase, in five years, would be 80 percent. This equates to an average annual growth rate in the customer charge of more than 15 percent. During the last five years, general inflation has only been in the 2 percent to 3 percent range. Clearly, CPA's desire to collect more and more of its revenue requirement from fixed monthly charges has not adhered to the concept of gradualism. In this regard, it is also important to note that in CPA's base rate proceeding at Docket No. R-2014-2407345 the parties agreed to a settlement in which the Commission approved a Weather Normalization Adjustment mechanism that eliminated virtually all risks associated with weather variability. Nevertheless, CPA continues to propose exceptionally large increases in the unavoidable fixed monthly customer charge paid by Residential consumers.

Q. SHOULD CPA'S PROPOSED RESIDENTIAL CUSTOMER CHARGE BE APPROVED?

A. No, for several reasons. First, CPA's customer cost calculations, which are relied upon to support the $20.60 Residential customer charge, are unreasonable because they include costs that are not customer costs. Second, CPA's Residential customer charge proposal is out of line with the Residential customer charges of other NGDCs in the Commonwealth. Third, as discussed in the testimony of OCA Witness Colton CPA's proposal will have a disproportionate impact on low-income customers. Finally, a high fixed monthly customer charge is inconsistent with the Commission's general goal of fostering energy conservation.

Q. WHY IS CPA'S CALCULATED RANGE OF CUSTOMER COSTS OF $18.15 TO $35.90, WHICH THE COMPANY USES TO SUPPORT THE $20.60 CHARGE, UNREASONABLE?

A. A customer charge should only include those basic costs associated with serving customers, regardless of their usage or demand characteristics. Customer costs include the expenses and capital costs related to meters, regulators, and services, as well as expenses related to meter reading and billing. The Company's calculated customer charge of $35.90 is unreasonable because it includes an allocated portion of mains investment that has consistently been rejected by this Commission. The calculated customer charge of $18.15 is unreasonable because it includes an allocation of costs not properly reflected in the fixed monthly charge: expenses associated with uncollectibles, miscellaneous, informational, demonstration, and advertising.

Q. HOW DOES CPA'S RESIDENTIAL CUSTOMER CHARGE PROPOSAL COMPARE WITH THE MONTHLY RESIDENTIAL CUSTOMER CHARGES OF OTHER NGDCs IN THE COMMONWEALTH?

A. Table 8 provides a comparison of CPA's Residential customer charge proposal with the customer charges of other Pennsylvania NGDCs. As shown there, CPA's current charge is already the highest in the Commonwealth, and if adopted, CPA's proposed monthly Residential customer charge would be significantly higher than that of any other NGDC in the Commonwealth.

Table 8. Comparison of Residential Customer Charges for Pennsylvania NGDCs	
Columbia Gas of Pennsylvania – Proposed	**$20.60**
Columbia Gas of Pennsylvania – Current	**16.75**
Peoples TWP	15.75
UGI Central Pennsylvania	14.60
Peoples Natural Gas	13.95
Peoples – Equitable Division	13.25
UGI Penn Natural Gas	13.17
Philadelphia Gas Works	12.00
National Fuel Gas Company	12.00
PECO Energy Company	11.75
UGI Gas Utilities	8.55

Q. WHY IS A HIGH FIXED MONTHLY CUSTOMER CHARGE INCONSISTENT WITH THE COMMISSION'S GENERAL GOAL OF FOSTERING ENERGY CONSERVATION?

A. The more revenue collected through the fixed monthly charge, the lower the volumetric charge. The higher the volumetric charge, the greater the incentive to lower usage.

Q. HAVE YOU CALCULATED A CUSTOMER CHARGE THAT ELIMINATES THE COSTS NOT PROPERLY REFLECTED IN A CUSTOMER CHARGE CALCULATION?

A. Yes. A customer charge calculation that eliminates the cost not properly reflected in such a calculation is presented in Schedule JDM-5 at CPA's requested revenue increase. My calculation indicates a Residential customer charge of $17.13.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO CPA'S MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. CPA's monthly Residential customer charge is already the highest in the Commonwealth. Based on CPA's requested increase, a cost-based charge would be $17.13. At the revenue increase authorized by the Commission in this proceeding, a cost-based charge would certainly be less than the current charge. Therefore, I recommend that the existing $16.75 monthly charge be maintained.

V. SERVICE EXPANSION PROPOSALS

Q. PLEASE DESCRIBE CPA'S CURRENT LINE EXTENSION POLICY.

A. When a potential customer requests CPA to extend its facilities, the Company uses an economic analysis to determine the cost of serving that customer, as described in Section 8.2 of its tariff. This analysis compares the net present value (NPV) of the projected future revenue for that customer, to the cost to add the customer. If the result is positive, that is, the projected customer revenues are greater than or equal to the projected cost, then the Company will make the line extension without cost to the customer. However, if the result is negative, that is, projected costs are greater than projected revenues, CPA requires the customer to pay a deposit for service. The deposit amount is the amount required to make the analysis whole. This same approach is used if CPA is approached by multiple potential customers to be served off a single extension of facilities.

Q. PLEASE EXPLAIN THE COMPANY'S EXISTING NEW AREA SERVICE RIDER.

A. For Residential customers that do not have the ability to pay the deposit up front, the Company currently offers a pilot New Area Service Rider (NAS). Rider NAS allows the customer to pay the deposit on their monthly bills over a period of 20 years, with interest.

Q. SINCE RIDER NAS IS INTENDED TO PROVIDE AN OPTION TO ENABLE MORE POTENTIAL CUSTOMERS TO ELECT NATURAL GAS SERVICE, WHY IS THE COMPANY OFFERING ADDITIONAL SERVICE EXTENSION OPTIONS?

A. The Company identifies one of the most significant barriers for customers to convert to natural gas as the up-front deposit. While Rider NAS reduces this barrier by spreading the cost of the deposit over a period of time, it does not reduce the overall cost to a customer to have the Company extend its facilities to serve them, nor does it assist the customer in the up-front costs of installing piping at their home for their natural gas appliances. In addition, it appears that CPA's proposal is being made in response to a statement made by Commissioner Witmer issued at the time of the Commission's approval of Rider NAS. In that statement, Commissioner Witmer, in stating her support of innovative programs to encourage the extension of natural gas into underserved and unserved areas of the Commonwealth, found Rider NAS to be underwhelming in achieving those service extension goals.

Q. PLEASE DESCRIBE CPA'S PROPOSALS TO EXPAND THE AVAILABILITY OF NATURAL GAS SERVICE IN ITS SERVICE TERRITORY.

A. CPA is proposing three incentives that, alone and in combination with Rider NAS, are designed to further encourage more customers to elect natural gas service: (1) a footage allowance of 150 feet of main line per applicant without the need for an NPV analysis in normal situations; (2) an allowance of 150 feet of service line in normal situations for customers served in those portions of CPA's service territory where the Company owns the service line; and (3) reimbursement of up to $1,000 for the installation of house piping on projects when projected revenues exceed projected costs by a certain threshold.

Q. PLEASE ELABORATE ON THE COMPANY'S PROPOSALS TO EXPAND SERVICE.

A. CPA currently does not offer any main or service footage allowance for customers to convert to natural gas service. CPA is proposing to modify its main and service extension tariff for Residential customers to install the first 150 feet of main and service without charge in normal situations without conducting an NPV analysis. For projects in which the economic analysis results are positive (i.e., revenues exceed costs) by at least $1,000 per customer, inclusive of the actual main and service extension costs, the Company is proposing to reimburse customers for a portion of the cost of the installation of the house piping required for natural gas service, up to $1,000 per customer.

Q. SHOULD CPA'S SERVICE EXPANSION PROPOSALS BE APPROVED?

A. Yes. I agree with Commissioner Witmer's statement that as currently structured, Rider NAS is underwhelming and will not do enough to encourage the extension of natural gas in CPA's service territory. In the Rider NAS proceeding, the OCA made several recommendations to make Rider NAS more effective in promoting the expansion of natural gas service. These recommendations included using the Company's cost of debt in the NPV calculation rather than its cost of capital, reducing the financing rate for Rider NAS deposit payments and excluding the costs associated with service lines, meters and, regulating equipment from the Company's NPV calculation. The Commission did not adopt these recommendations in its final order. I do, however, support the Company's additional proposals to promote the expansion of natural gas service as these proposals address some of the barriers to natural gas mains extension.

Q. ARE YOU PROPOSING ANY CHANGES TO THE COMPANY'S NPV CALCULATIONS?

A. Yes. While I will not raise here the issues that the Commission decided in its recent Rider NAS order, it is my understanding that CPA's NPV calculations include customer revenue contributions based on current rates. This is unreasonable because CPA's base rates will increase over the 40 year period currently included in the Company's NPV calculations. I recommend that CPA's NPV calculations be modified to include a 5 percent annual revenue escalation factor.

Q. IN THE RIDER NAS PROCEEDING THE COMMISSION APPROVED CERTAIN REPORTING REQUIREMENTS IN ORDER TO ASSESS THE EFFECTIVENESS OF THE PROGRAM. SHOULD SIMILAR REPORTING REQUIREMENTS BE ADOPTED FOR CPA'S NEW SERVICE EXPANSION PROPOSALS?

A. Yes. With these modifications, it will be important to collect and compare data under the existing model and the new model to determine if the objectives are being met. I recommend that the following reporting requirements be adopted. This information should be provided to I&E, the OCA, OSBA, and other interested parties on an annual basis:

a. Main and service investment per project;

b. NPV model results for each project, inclusive of the main and service allowances;

c. NPV model results for those projects requiring a customer deposit, exclusive of the main and service allowances;

d. Required NAS deposit by project;

e. House piping reimbursement per project;

f. Number of customers connected by each project and number of subsequent connections;

g. Annual revenues received by project, by type (i.e., base rate, and NAS revenues segregated by principal and interest);

h. Annual usage by project;

i. Average investment cost per customer by project; and

j. Number of new service requests evaluated but declined by the Company.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does at this time.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 3, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: Jerome D. M
Jerome D. Mierzwa

Consultant Address:
Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044

DATED: June 17, 2015

OCA Statement No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2015-2468056
COLUMBIA GAS OF PENNSYLVANIA, INC.	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 19, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

Schedule JDM-1

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RSS/RDS (D) $	SGSS/SCD/SGDS (E) $	N/A (F) $	SDS/LGSS (G) $	LDS/LGSS (H) $	MLDS (I) $
1	TOTAL REVENUE [PAGE 6]		534,899,150	387,272,028	110,411,419	-	18,824,782	16,650,402	1,740,519
2	PRODUCTS PURCHASED [PAGE 7]		190,479,760	133,198,003	51,541,083	-	4,656,534	812,004	272,136
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		177,299,816	132,105,508	24,655,934	-	7,180,422	13,335,963	21,990
4	DEPRECIATION & AMORTIZATION [PAGE 5]		54,751,328	35,833,710	9,894,695	-	3,107,102	5,894,549	21,271
5	TAXES OTHER THAN INCOME [PAGE 9]		3,221,085	2,176,548	554,765	-	170,439	318,866	467
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		425,751,989	303,313,769	86,646,477	-	15,114,498	20,361,382	315,863
7	OPERATING INCOME BEFORE TAXES		109,147,161	83,958,259	23,764,942	-	3,710,284	(3,710,979)	1,424,656
8	INCOME TAXES [PAGE 11]		29,190,575	24,709,288	6,789,991	-	541,850	(3,436,976)	586,421
9	INVESTMENT TAX CREDIT	12	(360,240)	*(228,709)*	*(67,048)*	-	*(22,097)*	*(42,267)*	*(119)*
10	NET INCOME TAXES		28,830,335	24,480,579	6,722,943	-	519,753	(3,479,243)	586,302
11	OPERATING INCOME		80,316,826	59,477,680	17,041,999	-	3,190,531	(231,737)	838,353
12	RATE BASE [PAGE 10]		1,325,130,928	832,680,611	253,582,435	-	82,232,694	156,253,199	381,990
13	RATE OF RETURN EARNED ON RATE BASE		6.061%	7.143%	6.720%	0.000%	3.880%	-0.148%	219.470%
14	UNITIZED RETURN		1.00	1.18	1.11	0.00	0.64	(0.02)	36.21

Schedule JDM-2

COLUMBIA GAS OF PENNSYLVANIA, INC.
Development of Proportional Responsibilty Mains Cost Allocation Factors

COMPANY PROJECTED SALES

	Company	RSS/RDS	SGSS	SDS	LDS
Jan	11,871,100	6,387,968	2,773,425	879,856	1,829,852
Feb	11,888,608	6,311,938	2,814,772	919,092	1,842,807
Mar	10,409,706	5,498,960	2,397,405	748,119	1,765,223
Apr	7,163,810	3,429,000	1,498,098	631,008	1,605,704
May	4,420,997	1,687,000	717,708	466,086	1,550,204
Jun	3,246,176	874,000	455,274	395,977	1,520,925
July	2,717,894	549,000	321,570	348,310	1,499,014
Aug	2,672,487	530,000	286,871	359,522	1,496,094
Sep	2,667,436	551,000	311,429	362,611	1,442,397
Oct	3,352,007	919,000	473,985	432,752	1,526,270
Nov	5,652,669	2,381,000	1,044,128	618,449	1,609,092
Dec	9,184,966	4,661,000	2,017,520	769,170	1,737,276
Total	75,247,857	33,779,865	15,112,184	6,930,950	19,424,858

COMPANY PROJECTED SENDOUT

Fuel: 0.5%

	Total X-ML	RSS/RDS	SGSS	SDS	LDS
Nov	5,681,075	2,392,965	1,049,375	621,556	1,617,178
Dec	9,231,121	4,684,422	2,027,658	773,035	1,746,006
Jan	11,930,754	6,420,068	2,787,361	884,277	1,839,048
Feb	11,948,350	6,343,656	2,828,917	923,710	1,852,067
Mar	10,462,016	5,526,593	2,409,452	751,878	1,774,093
Apr	7,199,809	3,446,231	1,505,626	634,179	1,613,773
May	4,443,213	1,695,477	721,314	468,428	1,557,994
Jun	3,262,488	878,392	457,562	397,967	1,528,568
July	2,731,552	551,759	323,186	350,060	1,506,547
Aug	2,685,917	532,663	288,313	361,328	1,503,612
Sep	2,680,840	553,769	312,994	364,433	1,449,645
Oct	3,368,851	923,618	476,367	434,927	1,533,939
Total	75,625,987	33,949,613	15,188,125	6,965,779	19,522,470

PROPORTIONATE RESPONSIBILTY FACTOR DEVELOPMENT

	Rank	Percent of Peak	Next Ranked Month	Next Ranked Percent of Peak	Difference	Individual Weighting	Rank		Cumulative Weighting	RSS/RDS	SGSS	SDS	LDS
	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)			
Nov	6	47.5469%	7	37.1868%	10.3601%	1.7267%	6	Nov	5.5280%	2.3285%	1.0211%	0.6048%	1.5736%
Dec	4	77.2585%	5	60.2578%	17.0008%	4.2502%	4	Dec	12.3204%	6.2521%	2.7062%	1.0317%	2.3303%
Jan	2	99.8527%	3	87.5603%	12.2924%	6.1462%	2	Jan	21.9005%	11.7849%	5.1166%	1.6232%	3.3758%
Feb	1	100.0000%	2	99.8527%	0.1473%	0.1473%	1	Feb	22.0478%	11.7057%	5.2201%	1.7045%	3.4175%
Mar	3	87.5603%	4	77.2585%	10.3018%	3.4339%	3	Mar	15.7543%	8.3223%	3.6283%	1.1322%	2.6715%
Apr	5	60.2578%	6	47.5469%	12.7108%	2.5422%	5	Apr	8.0702%	3.8628%	1.6876%	0.7108%	1.8089%
May	7	37.1868%	8	28.1951%	8.9917%	1.2845%	7	May	3.8013%	1.4505%	0.6171%	0.4008%	1.3329%
Jun	9	27.3049%	10	22.8613%	4.4436%	0.4937%	9	Jun	2.4055%	0.6477%	0.3374%	0.2934%	1.1271%
July	10	22.8613%	11	22.4794%	0.3819%	0.0382%	10	July	1.9118%	0.3862%	0.2262%	0.2450%	1.0544%
Aug	11	22.4794%	12	22.4369%	0.0425%	0.0039%	11	Aug	1.8736%	0.3716%	0.2011%	0.2521%	1.0489%
Sep	12	22.4369%	-	0.0000%	22.4369%	1.8697%	12	Sep	1.8697%	0.3862%	0.2183%	0.2542%	1.0110%
Oct	8	28.1951%	9	27.3049%	0.8902%	0.1113%	8	Oct	2.5168%	0.6900%	0.3559%	0.3249%	1.1460%
								Allocation Factors:		48.1885%	21.3359%	8.5777%	21.8980%

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

ALLOCATED COST OF SERVICE
PROPORTIONAL RESPONSIBILITY

Schedule JDM-3

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RSS/RDS (D) $	SGSS/SCD/SGDS (E) $	N/A (F) $	SDS/LGSS (G) $	LDS/LGSS (H) $	MLDS (I) $
1	TOTAL REVENUE [PAGE 6]		534,899,150	387,267,701	110,410,751	-	18,824,785	16,655,394	1,740,519
2	PRODUCTS PURCHASED [PAGE 7]		190,479,760	133,198,003	51,541,083	-	4,656,534	812,004	272,136
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		177,299,816	128,112,622	24,171,817	-	7,359,244	17,581,490	74,643
4	DEPRECIATION & AMORTIZATION [PAGE 5]		54,751,328	34,343,114	9,664,847	-	3,108,398	7,613,698	21,271
5	TAXES OTHER THAN INCOME [PAGE 9]		3,221,085	2,095,177	542,680	-	171,136	411,429	664
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		425,751,989	297,748,915	85,920,427	-	15,295,312	26,418,621	368,714
7	OPERATING INCOME BEFORE TAXES		109,147,161	89,518,787	24,490,324	-	3,529,473	(9,763,227)	1,371,805
8	INCOME TAXES [PAGE 11]		29,190,575	27,502,463	7,165,861	-	466,354	(6,508,586)	564,483
9	INVESTMENT TAX CREDIT	12	(360,240)	(217,938)	(65,387)	-	(22,108)	(54,688)	(119)
10	NET INCOME TAXES		28,830,335	27,284,525	7,100,474	-	444,246	(6,563,274)	564,364
11	OPERATING INCOME		80,316,826	62,234,262	17,389,850	-	3,085,227	(3,199,953)	807,441
12	RATE BASE [PAGE 10]		1,325,130,928	792,633,489	247,411,220	-	82,271,364	202,432,064	382,790
13	RATE OF RETURN EARNED ON RATE BASE		6.061%	7.852%	7.029%	0.000%	3.750%	-1.581%	210.935%
14	UNITIZED RETURN		1.00	1.30	1.16	0.00	0.62	(0.26)	34.80

Schedule JDM-4

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2016

Line No.		Description	Total (1)	RS/RDG/RGSS RDS/ RDGDS/RCC (2)	SGSS/SCD/SGDS (3)	SDS/LGS (4)	LDS/LGS (5)	MDS/NSS (6)
1		**Determination of Revenue Distribution**						
2		Rate Base (Exhibit 111, Schedule 1, Page 2, Line 12)	$1,325,130,929	$832,680.611	$253,582,435	$82,232,694	$156,253,199	$381,990
3								
4		Unitized Return @ Current Rates (Exhibit 111, Schedule 1, Page 2, Line 14)	1.00000	1.18000	1.11000	0.64000	(0.02000)	36.21000
5		**Proposed Unitized Return**	**1.00000**	**1.14750**	**1.08000**	**0.80000**	**0.12568**	**26.96200**
6		**Change in Unitized Return**	**0.00000**	**(0.03250)**	**(0.03000)**	**0.16000**	**0.14568**	**(9.24800)**
7		Rate of Return Requested	8.140%	9.341%	8.791%	6.512%	1.023%	219.471%
8		Net Operating Income @ Requested Return (Line 2 x Line 7)	$107,865,658	$77,780,696	$22,292,432	$5,354,993	$1,599,180	$838,357
9		Net Operating Income @ Current Rates (Exhibit 111, Sch. 1, Page 2, Line 11)	$80,316,826	$59,477,680	$17,041,999	$3,190,531	($231,737)	$838,353
10		Income Deficiency (Line 8 - Line 9)	$27,548,832	$18,303,016	$5,250,433	$2,164,462	$1,830,917	$4
11		Gross Converstion Factor	1.67602331	1.67602331	1.67602331	1.67602331	1.67602331	1.67602331
12		**Revenue Required Increase (Exhibit 102 Sch. 3 Page 3)**	**46,172,485**	**30,676,281**	**8,799,848**	**3,627,689**	**3,068,660**	**7**
13		**Percent Distribution to Rate Classes**	**100.00%**	**66.43%**	**19.06%**	**7.86%**	**6.65%**	**0.00%**
14	Less:	Proposed Change in STAS (Page 1 Line 30 through Line 43)	0	0	0	0	0	0
15	Less:	Proposed Change Other Gas Department Revenue (Page 1 Line 14)	113,901	75,674	21,708	8,949	7,570	0
16	Less:	Proposed Change in Rider CC (Page 2 Line 1 through Line 14)	4,656	3,141	1,515	0	0	0
17	Less:	Shift Inc. Emergency Repairs Program to USP (Witness Krajovic, Statement 6)	100,000	100,000	0	0	0	0
18	Less:	Shift Emergency Repairs Program to USP (Witness Krajovic, Statement 6)	500,000	500,000	0	0	0	0
19	Less:	Shift CAP Application Administration Chg to USP (Witness Krajovic, Statement 6)	170,000	170,000	0	0	0	0
20	Less:	Proposed Change in Choice Admin. Charge Revenue (Page 2 Line 17 through Line 29)	960,011	405,888	477,366	63,087	13,014	656
21	Less:	Proposed Change in Gas Procurement Revenue (Page 2 Line 32 through Line 42)	(1,768,130)	(1,231,548)	(482,901)	(45,710)	(7,971)	0
22		**Proposed Increase to Base Revenue**	**$46,092,047**	**$30,653,126**	**$8,782,160**	**$3,601,363**	**$3,056,047**	**($649)**
23		**Percent Distribution to Rate Classes**	**100.00%**	**66.51%**	**19.05%**	**7.81%**	**6.63%**	**0.00%**
24		**Current Base Revenue**	**$310,753,903**	**$221,761,702**	**$57,705,207**	**$14,052,431**	**$15,769,810**	**$1,464,753**
25		**Current Percent Distribution of Rate Classes**	**100.00%**	**71.36%**	**18.57%**	**4.52%**	**5.08%**	**0.47%**
26		**Proposed Base Revenue**	**$356,845,950**	**$252,414,828**	**$66,487,367**	**$17,653,794**	**$18,825,857**	**$1,464,104**
27		**Proposed Percent Distribution of Rate Classes**	**100.00%**	**70.74%**	**18.63%**	**4.95%**	**5.28%**	**0.41%**
28		**Proposed Increase Percent**	**14.83%**	**13.82%**	**15.22%**	**25.63%**	**19.38%**	**-0.04%**

Schedule JDM-5

COLUMBIA GAS OF PENNSYLVANIA, INC.

Analysis of Residential Customer Costs (1)

Annual Customer Base Costs per Company	$	85,360,555
OCA Adjustments:		
Uncollectibles	$	(4,093,887)
Miscellaneous	$	(33,432)
Demonstation	$	(617,323)
Advertising	$	(17,778)
Total OCA Adjustments	$	(4,762,420)
Annual Customer Base Costs per OCA	$	80,598,135
Average Annual Customer Bills		4,704,314
Monthly Customer Charge	$	17.13

Note: (1) Costs from Exhibit No. 111, Schedule 1, pages 17 - 18.

Appendix A

JEROME D. MIERZWA

Mr. Mierzwa is a Principal of Exeter Associates, Inc., with 24 years of public utility regulatory experience. At Exeter, Mr. Mierzwa has been involved in purchased gas cost allocation analysis and rate design analysis, conducting management audits and similar investigations of the natural gas supply and procurement policies and practices of local distribution companies (LDCs), and has provided assistance in proceedings before the Federal Energy Regulatory Commission (FERC). Mr. Mierzwa has participated in the planning of natural gas procurements for major federal installations located in various regions of the country. Mr. Mierzwa has been involved in evaluating performance-based incentive regulation for LDC purchased gas costs and the unbundling of LDC services. Mr. Mierzwa has participated in developing utility class cost-of-service studies, has presented testimony sponsoring gas, water and wastewater utility cost-of-service studies, least cost gas procurement and incentive regulation, in addition to presenting testimony addressing utility rate base and revenues.

Education

B.S. (Marketing) – Canisius College, Buffalo, New York, 1981

M.B.A. (Finance) – Canisius College, Buffalo, New York, 1985

Gas Rates Fundamental Course, June 1987, University of Wisconsin, sponsored by the American Gas Association.

Previous Employment

1986-1990	Rate Analyst National Fuel Gas Company Buffalo, New York

Previous Experience

Prior to joining Exeter in 1990, Mr. Mierzwa served as a rate analyst at National Fuel Gas Supply Corporation, an interstate pipeline. In that position, he was involved in preparing purchased gas adjustment filings and reviewing the rate filings of interstate pipeline suppliers. Mr. Mierzwa was also involved in preparing supplier rate, gas sales, and gas purchase price forecasts, examining the rate implications of storage activity, and analyzing rate of return, cash working capital, and potential merger and acquisition candidates.

Presentations

The NASUCA annual meetings in San Antonio, Texas, November 1991 (presentation concerning the FERC Mega-NOPR proceeding which led to the adoption of FERC Order No. 636).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning spot market gas incentive procurement programs).

Expert Testimony

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 90-17-GA-GCR), November 1990. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination.)

City of Great Falls Wastewater Utility (Montana Public Service Commission Docket No. 90.10.66), March 1991. Presented a cost of service study on behalf of the U.S. Air Force.

City of Great Falls Water Utility (Montana Public Service Commission Docket No. 90.10.67), March 1991. Presented a cost of service study on behalf of the U.S. Air Force.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio, Case No. 91-16-GA-GCR), October 1991. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination.)

Louisiana Gas Service Company (Louisiana Public Service Commission Docket No. U-19237), December 1991. Testified on rate base including cash working capital, cost allocation and rate design on behalf of the Louisiana Public Service Commission.

Equitable Gas Company and Jefferson Gas Company (Pennsylvania Public Utility Docket No. R-00912164), April 1992. Presented a revised forecast of test year sales and revenues on behalf of the Pennsylvania Office of Consumer Advocate.

Peoples Natural Gas Company (Pennsylvania Public Utility Docket Nos. R-00922180 and R-00922206), May 1992. Presented testimony sponsoring a revised forecast of purchased gas costs and on least cost gas procurement on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-922323), July 1992. Presented testimony on the allocation of purchased gas costs and the projection of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 2048), August 1992. Presented testimony sponsoring a class cost of service study, cash working capital and revenues on behalf of the Division of Public Utilities and Carriers.

Dallas, Harvey's Lake, Noxen and Shavertown Water Companies (Pennsylvania Public Utility Docket Nos. R-922326, R-922327, R-922328 and R-922329) September 1992. Presented testimony on rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 92-18-GA-GCR). January 1993. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00922499), March 1993. Presented testimony on the allocation of purchased gas costs, FERC Order No. 636 transition costs and the projection of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Docket No. R-00922476), March 1993. Presented testimony addressing test year revenues and expenses on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Docket No. R-00932598), May 1993. Presented testimony on the allocation of purchased gas costs, FERC Order No. 636 transition costs and least cost gas procurement on behalf of the Pennsylvania Office of Consumer Advocate.

Dauphin Consolidated Water Supply Company and General Waterworks of Pennsylvania, Inc. (Pennsylvania Public Utility Docket No. R-00932604), June 1993. Presented testimony addressing test year net operating income on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00932548), July 1993. Presented testimony addressing test year revenues and FERC Order No. 636 transition costs on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission Docket No. RP93-73-000), July 1993. Presented testimony addressing test year throughput and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00932674), July 1993. Presented testimony on the allocation of purchased gas costs, FERC Order No. 636 transition costs and least cost gas procurement on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company, Gas Operations (Nevada Public Service Commission Docket No. 93-4087), September 1993. Presented testimony on the allocation of purchased gas costs to electric and gas operations on behalf of the Nevada Office of Consumer Advocate.

Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 93-14-GA-GCR), October 1993. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00932927), March 1994. Presented testimony on transportation service balancing requirement modifications and service enhancements in response to FERC Order No. 636 on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00932885), April 1994. Presented testimony addressing the allocation of purchased gas costs, FERC Order No. 636 transition costs, incentive rate mechanisms, and the projection of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Docket No. R-00943028), April 1994. Presented testimony addressing the allocation of purchased gas costs, FERC Order No. 636 transition costs, take-or-pay costs, incentive rate mechanisms and the projection of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Citizens Gas & Coke Utility (Indiana Utility Regulatory Commission, Cause No. 37399-GCA41), May 1994. Presented testimony addressing the allocation and recovery of Order No. 636 transition costs on behalf of the Indiana Utility Consumer Counselor.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00943064), July 1994. Presented testimony addressing the allocation of purchased gas costs and incentive rate mechanisms on behalf of the Pennsylvania Office of Consumer Advocate.

National Gas & Oil Corporation (Public Utilities Commission of Ohio, Case No. 94-221-GA-GCR), October 1994. Co-authored report on audit of management and performance of gas procurement activity on behalf of the Public Utilities Commission of Ohio.

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19997), November 1994. Presented testimony addressing the results of a Commission-ordered investigation into the purchased gas adjustment clause of Trans Louisiana Gas Company on behalf of the Louisiana Public Service Commission Staff.

NorAm Gas Transmission Company (Federal Energy Regulatory Commission Docket No. RP94-343-000), March 1995. Presented testimony addressing rate design billing determinants and the treatment of revenues associated with short term firm, interruptible and other services on behalf of the Arkansas and Louisiana Public Service Commissions.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00953297), May 1995. Presented testimony addressing the allocation of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Docket No. R-00953318), May 1995. Presented testimony addressing the acquisition of capacity resources, transportation balancing charges, performance-based incentive programs and lost and unaccounted-for and company use gas.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00953299), June 1995. Presented testimony addressing storage working capital requirements, heating degree days to be utilized for weather normalization purposes and sponsored a class cost of service on behalf of The Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00953374), July 1995. Presented testimony addressing the acquisition of interstate pipeline capacity and the allocation of purchased gas costs on behalf of The Pennsylvania Office of Consumer Advocate.

Atlanta Gas Light Company (Georgia Public Service Commission Docket No. 5650-U), August 1995. Presented testimony addressing operations of the Company's purchased gas adjustment mechanism and gas procurement practices and policies on behalf of the Georgia Consumers' Utility Counsel.

United Cities Gas Company (Georgia Public Service Commission Docket No. 5651-U), August 1995. Presented testimony addressing the allocation of purchased gas costs on behalf of the Georgia Consumers' Utility Counsel.

Eastern and Pike Natural Gas Companies (Public Utilities Commission of Ohio, Case Nos. 95-215-GA-GCR and 95-216-GA-GCR), September 1995. Co-authorized report on audit of management and performance of gas procurement activity on behalf of the Public Utilities Commission of Ohio.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission Docket No. RP95-112-000), September 1995. Presented testimony addressing rate design determinants and revenues associated with long term firm, short term firm and interruptible services on behalf of the Pennsylvania Office of Consumer Advocate.

North Shore Gas Company and Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket Nos. 95-0490 and 95-0491), January 1996. Presented testimony evaluating performance-based rate programs for purchased gas costs on behalf of the Citizens Utility Board.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00953487), March 1996. Presented testimony addressing incentive rate mechanisms, the allocation of purchased gas costs and unauthorized service on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Docket No. R-00963563), May 1996. Presented testimony addressing the allocation of purchased gas costs and the projection of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

North Penn Gas Company and PFG Gas, Inc. (Pennsylvania Public Utility Docket No. R-00963636), July 1996. Presented testimony addressing the recovery of excess interstate pipeline capacity costs on behalf of the Pennsylvania Office of Consumer Advocate.

Dayton Power & Light Company (Public Utilities Commission of Ohio, Case No. 96-220-GA-GCR), September 1996. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

West Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 96-221-GA-GCR), November 1996. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

Northern Illinois Gas Company (Illinois Commerce Commission Docket No. 96-0386), November 1996. Presented testimony evaluating performance-based rate programs for purchased gas costs on behalf of the Citizens Utility Board.

National Fuel Gas Distribution (Pennsylvania Public Utilities Commission Docket No. R-00963779), March 1997. Presented testimony addressing the allocation of purchased gas costs and gas procurement practices and policies on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utilities Commission Docket No. R-00973895), May 1997. Presented testimony addressing the allocation of purchased gas costs and gas procurement practices and policies on behalf of the Pennsylvania Office of Consumer Advocate.

Southwest Gas Corporation (Nevada Public Service Commission Docket No. 97-2005), June 1997. Presented testimony addressing the allocation of purchased gas costs and gas procurement practices and policies on behalf of the Nevada Office of Consumer Advocate.

Kent County Water Authority, (Rhode Island Public Utilities Commission Docket No. 2555), June 1997. Presented class cost of service testimony on behalf of the Division of Public Utilities and Carriers.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00974012), July 1997. Presented testimony on the allocation of purchased gas costs, and the computation of off-system sales margins and margin sharing procedures on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania American Water Company (Pennsylvania Public Utility Docket No. R-00973944), July 1997. Presented class cost of service and rate design testimony on behalf of the Pennsylvania Office of Consumer Advocate.

Commonwealth Gas Services, Inc. (Virginia State Corporation Commission Case No. PUE970455), August 1997. Presented testimony addressing the Company's retail unbundling pilot program on behalf of the Division of Consumer Counsel, Office of the Attorney General.

Consumers Pennsylvania Water Company, Shenango Valley Division (Pennsylvania Public Utility Docket No. R-00973972), September 1997. Presented class cost of service and rate design testimony on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company, Water Department (Nevada Public Service Commission Docket No. 97-9020), January 1998. Presented class cost of service and rate design testimony on behalf of the Nevada Utility Consumers' Advocate.

Southern Union Gas Company (City of El Paso, Texas) Inquiry into Southern Union Gas Company's Purchased Gas Adjustment Clause, March 1998. Presented testimony addressing the reasonableness of the Company's gas procurement practices and policies on behalf of the City of El Paso, Texas.

East Ohio Gas Company (Public Utilities Commission of Ohio Case No. 97-219-GA-GCR), March 1998. Co-authored report on the Company's residential and small commercial pilot transportation program on behalf of the Public Utilities Commission of Ohio.

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 98-222-GA-GCR), March 1998. Co-authored report on the Company's residential and small commercial pilot transportation program on behalf of the Public Utilities Commission of Ohio.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00974167), March 1998. Presented testimony on the allocation of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission Docket No. 2674), April 1998. Presented class cost of service testimony on behalf of the Division of Public Utilities and Carriers.

Equitable Gas Company (Pennsylvania Public Utilities Commission Docket No. R-00984279), May 1998. Presented testimony addressing the allocation of purchased gas costs and gas procurement practices and policies on behalf of the Pennsylvania Office of Consumer Advocate.

East Ohio Gas Company (Public Utilities Commission of Ohio Case No. 97-219-GA-GCR), May 1998. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-00984352), July 1998. Presented testimony on the allocation of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Natural Gas Company (Federal Energy Regulatory Commission Docket No. RP98-203-000), October 1998. Presented testimony addressing delivery point imbalance tolerance levels on behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association.

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 98-223-GA-GCR), January 1999. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

North Shore Gas Company and Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket Nos. 98-0819 and 98-0820), February 1999. Presented testimony addressing proposals to adopt fixed gas cost charges on behalf of the Citizens Utility Board.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00984497), March 1999. Presented testimony addressing the allocation of purchased gas costs, gas price projections and the appropriate level of capacity entitlements on behalf of the Pennsylvania Office of Consumer Advocate.

Delmarva Power and Light Company (Delaware Public Service Commission Docket No. 98-524), March 1999. Presented testimony addressing the Company's customer choice pilot program on behalf of the Division of Public Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Docket No. R-00994600), May 1999. Presented testimony addressing the contracting for interstate pipeline capacity and the obligation to serve on behalf of the Pennsylvania Office of Consumer Advocate.

Nicor Gas Company (Illinois Commerce Commission Docket No. 99-0127), May 1999. Presented testimony addressing performance-based rates for purchased gas costs on behalf of the Citizens' Utility Board.

Elizabethtown Gas Company, New Jersey Natural Gas Company, Public Service Electric & Gas Company and South Jersey Gas Company (New Jersey Board of Public Utilities Docket Nos. GX99030121 - GO99030125), July 1999. Presented testimony addressing the assignment of capacity by gas utilities to third-party suppliers and the recovery of stranded costs resulting from the unbundling of gas utility services on behalf of the Ratepayer Advocate.

New Jersey Natural Gas Company (New Jersey Board of Utilities Docket No. G099030122), July 1999. Presented testimony addressing the unbundling of gas utility services on behalf of the Ratepayer Advocate.

Carnegie Natural Gas Company (Pennsylvania Public Utility Commission Docket No. C-00970942), September 1999. Presented testimony addressing the design of sales and transportation rates on behalf of the Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00994782), September 1999. Presented testimony addressing the unbundling of gas utility services on behalf of the Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00994784), October 1999. Presented testimony addressing the unbundling of gas utility services on behalf of the Office of Consumer Advocate.

City of Newport-Water Division (Public Utilities Commission of Rhode Island Docket No. 2985), December 1999. Presented testimony addressing cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Entergy Gulf States, Inc. (Public Utilities Commission of Texas Docket No. 2111), December 1999. Presented testimony addressing the recovery of purchased power and purchased gas costs on behalf of certain Cities served by Entergy Gulf States, Inc.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00994785), December 1999. Presented testimony addressing gas supply, unbundling and rate design restructuring issues on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc. - Gas Division (Pennsylvania Public Utility Commission Docket No. R-00994786), December 1999. Presented testimony addressing gas supply, unbundling and rate design restructuring issues on behalf of the Pennsylvania office of Consumer Advocate.

Cincinnati Gas & Electric Company (Public Utilities Commission) of Ohio Case No. 99-218-GA-GCR), January 2000. Co-authored report on management performance audit of gas purchasing practices on behalf of the Public Utilities Commission of Ohio.

T.W. Phillips Gas and Oil Company (Pennsylvania Public Utility Commission Docket No. R-00994790), April 2000. Presented testimony addressing gas supply, unbundling and rate design restructuring issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00994898), April 2000. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00005067), May 2000. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-00005285), July 2000. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc. -- Gas Division (Pennsylvania Public Utility Commission Docket No. R-00005281), July 2000. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Providence Water Supply Board (Public Utilities Commission of Rhode Island Docket No. 3163), October 2000. Presented testimony addressing cost allocation and rate design on behalf of the Division of Public Utilities and Carriers.

Nicor Gas Company (Illinois Commerce Commission Docket Nos. 00-0620/00-0621), December 2000. Presented testimony addressing customer choice on behalf of the Citizens Utility Board.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00005832), April 2001. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00016115), May 2001. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00016132), May 2001. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Dayton Power & Light Company (Public Utilities Commission of Ohio Case No. 00-220-GA-GCR), May 2001. Co-authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

UGI Utilities, Inc. -- Gas Division (Pennsylvania Public Utility Commission Docket No. R-00016376), July 2001. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Shore Gas Company (Illinois Commerce Commission Docket No. 01-0469), September 2001. Presented testimony addressing gas supply, unbundling and restructuring customer choice issues on behalf of the Citizens Utility Board, Cook County State's Attorney's Office and the People of the State of Illinois.

The Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket No. 01-0470), September 2001. Presented testimony addressing gas supply, unbundling and restructuring customer choice issues on behalf of the Citizens Utility Board, Cook County State's Attorney's Office and People of the State of Illinois.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-00016898), March 2002. Presented testimony addressing gas cost procurement practices and cost allocations on behalf of Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00016789), April 2002. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Illinois Gas Company (Illinois Commerce Commission Docket No. 02-0067), April 2002. Presented testimony addressing performance based gas cost incentive program on behalf of the Citizens Utility Board and Cook County State's Attorney's Office.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00027134), May 2002. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00027135), May 2002. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc. -- Gas Division (Pennsylvania Public Utility Commission Docket No. R-00027388), July 2002. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

The Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio Case No. 01-218-GA-GCR), July 2002. Co-authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-00027888), March 2003. Presented testimony addressing gas cost procurement practices and cost allocations on behalf of Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00038101), April 2003. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00038170), May 2003. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00038166), May 2003 Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc. – Gas Division (Pennsylvania Public Utility Docket No. R-00038411), July 2003. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 02-221-GA-GCR), July 2003. Co-authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

The Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket No. 01-0707), July 2003. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Citizens Utility Board.

UGI Utilities, Inc. – Gas Division (Pennsylvania Public Utility Commission Docket No. R-00049422), July 2004. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

PFG, Inc. and North Penn Gas Company (Pennsylvania Public Utility Docket No. R-00049424), July 2004. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

East Ohio Gas Company (Public Utilities Commission of Ohio Case No. 03-219-GA-GCR), August 2004. Co-authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

Southwest Gas Corporation (Nevada Public Services Commission Docket No. 04-6001), September 2004. Presented testimony addressing gas procurement practices on behalf of the Nevada Office of Consumer Advocate.

Northern Natural Gas Company (FERC Docket No. RP04-155-000), November 2004. Presented testimony on billing determinant to be used for rate design on behalf of the Northern Municipal Distributors Group and Midwest Region Gas Task Force Association.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 41338-GCA6), January 2005. Presented testimony addressing storage inventory pricing on behalf of the Indiana Office of Utility Consumer Counselor.

Citizens Gas & Coke Utility (Indiana Utility Regulatory Commission Cause No. 37399-GCA84-S1), February 2005. Presented testimony addressing gas exchange transactions on behalf of the Indiana Office of Utility Consumer Counselor.

Nicor Gas Company (Illinois Commerce Commission Docket No. 04-0779), February 2005. Presented testimony and addressing storage inventory carrying charges on behalf on the Citizens Utility Board and the Cook Country States' Attorney's Office.

Heartland Gas Pipeline, LLC and Citizens Gas & Coke Utility (Indiana Utility Regulatory Commission Cause Nos. 42729 and 42730), March 2005. Presented testimony addressing the petition of Heartland for a certificate of public convenience and necessity to construct an intrastate pipeline, and the petition of Citizens for approval of a storage service agreement on behalf of the Indiana Office of Utility Consumer Counselor.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-00040059), March 2005. Presented testimony addressing gas cost procurement practices and cost allocations on behalf of Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-00050216), March 2005. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Columbia Gas of Pennsylvania (Pennsylvania Public Utility Commission Docket No. R-00049783, May 2005. Presented testimony addressing fixed price sales services on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00050267), May 2005. Presented testimony addressing gas cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00050272), May 2005. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company and Public Service Electric and Gas Company (Pennsylvania Public Utility Commission Docket No. A-110550F0160), June 2005. Presented testimony addressing issues related to the post merger structure of the gas procurement function on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc. – Gas Division (Pennsylvania Public Utility Commission Docket No. R-00050539), July 2005. Presented testimony addressing gas procurement practices and gas cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

PPL Gas Utilities Corporation (Pennsylvania Public Utility Docket No. R-00050540), July 2005. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Utilities, Inc. (Maine Public Utilities Commission Docket No. 2005-87), July 2005. Presented testimony on gas cost allocation and the assignment of interstate pipeline capacity on behalf of the Maine Office of the Public Advocate.

Southwest Gas Corporation (Nevada Public Services Commission Docket No. 05-5015), September 2005. Presented testimony addressing purchased gas cost recovery rates on behalf of the Nevada Office of Consumer Advocate.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Case No. 41338-GCA7), December 2005. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Indiana Office of Utility Consumer Counselor.

Indiana Gas Company, Southern Indiana Gas and Electric and Citizens Gas & Coke Utility (Indiana Utility Regulatory Commission Cause No. 42973), February 2006. Presented testimony addressing gas cost allocation on behalf of the Indiana Office of Utility Consumer Counselor.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-00000051134), March 2006. Presented testimony addressing gas cost procurement practices and cost allocations on behalf of Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-61246), March 2006. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio Case No. 05-218-GA-GCR), April 2006. Authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00061301), May 2006. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00061295), May 2006. Presented testimony addressing gas procurement practices and cost allocation on behalf of the Pennsylvania Office of Consumer Advocate.

Atmos Energy Corporation (Louisiana Public Service Commission Docket No. U-27703), May 2006. Authored report on audit of gas purchasing practices and cost allocation on behalf of the Staff of the Louisiana Public Service Commission.

UGI Utilities, Inc. -- Gas Division (Pennsylvania Public Utility Commission Docket No. R-00061502), July 2006. Presented testimony addressing gas procurement practices on behalf of the Pennsylvania Office of Consumer Advocate.

PPL Gas Utilities Corporation (Pennsylvania Public Utility Docket No. R-00061519), July 2006. Presented testimony addressing gas procurement practices on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Resources Inc./The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. A-122250F500), September 2006. Presented testimony addressing gas costs issues in this merger proceeding on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Indiana Public Service Company (Indiana Regulatory Utility Commission Cause No. 41338-GCA8), October 2006. Presented testimony addressing reported gas costs and gas cost incentive mechanism results on behalf of the Indiana Office of Utility Consumer Counselor.

North Shore Gas Company/The Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket Nos. 05-0748 and 05-0749), January 2007. Presented testimony addressing gas cost issues on behalf of the Citizens Utility Board and the City of Chicago.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Docket No. R-00072043), March 2007. Presented testimony addressing the allocation of purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utilities Commission Docket No. R-00072111), May 2007. Presented testimony addressing the allocation of purchased gas costs and gas procurement practices and polices on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Docket No. R-00072109), May 2007. Presented testimony addressing gas procurement practices and policies and fuel retention charge discounting on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc., Gas Utility Division (Pennsylvania Public Utility Docket No. R-0072335), July 2007. Presented testimony on gas procurement practices and policies on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Docket No. R-00072334), July 2007. Presented testimony on gas procurement practices and policies on behalf of Pennsylvania Office of Consumer Advocate.

North Shore Gas Company/The Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket Nos. 07-0241 and 07-0242), July 2007. Presented testimony addressing the allocation of on-system storage on behalf of the Citizens Utility Board and City of Chicago.

Providence Water Supply Board (Public Utilities Commission of Rhode Island Docket No. 3832), July 2007. Addressed cost of service and rate design on behalf of the Division of Public Utilities and Carriers.

Dominion East Ohio Gas Company (Public Utility Commission of Ohio Case No. 07-219-GA-GCR), November 2007. Authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

Northern Indiana Public Service Company (Indiana Regulatory Utility Commission Cause No. 41338-GCA9), December 2007. Presented testimony addressing the reasonableness of reported gas costs and evaluating the results of the gas cost incentive mechanisms under which the company operates on behalf of the Indiana Office of Utility Commission Counselor.

Aqua Pennsylvania, Inc. (Pennsylvania Public Utility Commission Docket No. R-00072711), February 2008. Presented testimony addressing cost of service, rate design and purchased water rider on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utilities Commission Docket No. R-2008-2012502), March 2008. Presented testimony addressing design day forecasting and transportation service balancing charges on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-2008-2013026), March 2008. Presented testimony addressing the disposition of capacity release revenues on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-2008-2021160), May 2008. Presented testimony addressing exchange transactions on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2008-2039417), July 2008. Presented testimony addressing capacity release and off-system sales revenue sharing and the acquisition of incremental capacity on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2008-2039284), July 2008. Presented testimony addressing the acquisition of incremental capacity on behalf of the Pennsylvania Office of Consumer Advocate.

North Shore Gas Company/The Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket Nos. 06-0751 and 07-0311/06-752 and 07-0312), July 2008. Presented testimony addressing park and loan activities and out-of-period gas cost adjustments on behalf of the Citizens Utility Board and the City of Chicago.

Pawtucket Water Supply Board (Public Utilities Commission of Ohio Docket No. 3945), July 2008. Presented testimony addressing class cost of service and rate design on behalf of the Division of Public Utilities and Carriers

Philadelphia Water Department (Philadelphia Water Commission FY 2009-2012 Rates), July 2008. Presented testimony addressing water and waste water class cost of service and rate design on behalf of the Public Advocate.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 41338-GCA10), March 2009. Presented testimony addressing gas procurement and incentive mechanism issues on behalf of the Office of Utility Consumer Counselor.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Case No. 41338-GCA11), December 2009. Presented testimony addressing gas procurement and incentive mechanism issues on behalf of the Office of Utility Consumer Counselor.

City of Newport (Public Utilities Commission of Rhode Island), January 2010. Presented testimony sponsoring a water cost of service study on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utilities Commission Docket No. R-2010-2150861), March 2010. Presented testimony addressing design day forecasting and transportation service balancing charges on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-2009-2145441), March 2010. Presented testimony addressing capacity release revenues and retainage on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Natural Gas Company (Federal Energy Regulatory Commission Docket No. RP10-148), May 2010. Presented testimony addressing rate discounts on behalf of the Northern Municipal Distributors Group and Midwest Region Gas Task Force Association.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-2010-2155608), May 2010. Presented testimony addressing retainage and design peak day forecasting issues on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-2010-2155613), May 2010. Presented testimony addressing design peak day forecasting, balancing charges and off-system sales on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2010-2161592), June 2010. Presented testimony addressing base rate cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2010-2172933), July 2010. Presented testimony addressing supplier reservation charges and capacity assignment on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2010-2172928), July 2010. Presented testimony addressing supplier reservation charges and capacity assignment on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Central Penn Gas, Inc. (Pennsylvania Public Utility Commission Docket No. 2010-2172922), July 2010. Presented testimony addressing the assignment of capacity on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-2010-2167797), August 2010. Presented testimony addressing base rate cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

North Shore Gas Company/The Peoples Gas Light and Coke Company (Illinois Commerce Commission Docket Nos. 07-0576 and 07-0577), October 2010. Presented testimony addressing the reasonableness and allocation of purchased gas costs on behalf of the Citizens Utility Board.

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 10-221-GA-GCR), November 2010. Authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA16), November 2010. Presented testimony addressing gas procurement and incentive mechanism issues on behalf of the Office of Utility Consumer Counselor.

Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-2010-2201702), January 2011. Presented testimony addressing base rate cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. A-2010-221389), February, 2011. Presented testimony addressing the transfer of facilities to an affiliate on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Central Penn Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2010-2214415), April 2011. Presented testimony addressing base rate cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-2011-2228694), May 2011. Presented testimony addressing retainage and lost and unaccounted-for gas issues on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-2011-2223563), May 2011. Presented testimony addressing retainage issues on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2011-2238953), July 2011. Presented testimony addressing design peak day forecasting, winter season planning criteria and capacity RFP process on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2011-2238943), July 2011. Presented testimony addressing design peak day forecasting, winter season planning criteria and capacity RFP process on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Central Penn Gas, Inc. (Pennsylvania Public Utility Commission Docket No. 2011-2238949), July 2011. Presented testimony addressing the Company's winter season planning criteria and capacity RFP process on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Utilities, Inc. (Maine Public Utilities Commission Docket No. 2011-92), August 2011. *Presented testimony addressing cost allocation and rate design on behalf of the Maine* Public Advocate.

United Water Rhode Island, Inc. (Public Utilities Commission of Rhode Island Docket No. 4255), September 2011. Presented testimony addressing cost allocation and rate design on behalf of the Division of Public Utilities and Carriers.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA20), November 2011. Presented testimony addressing gas procurement and incentive mechanism issues on behalf of the Office of Utility Consumer Counselor.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utilities Commission Docket No. R-2012-2281465), March 2012. Presented testimony addressing design day forecasting, the allocation of capacity costs and pipeline penalties on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Gas & Oil Company (Pennsylvania Public Utility Commission Docket No. R-2011-2273539), March 2012. Presented testimony addressing the reconciliation of gas costs and revenues on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Gas Works (Pennsylvania Public Utility Commission Docket No. R-2012-2286447), April 2012. Presented testimony addressing interstate pipeline capacity and gas supply contracting practices on behalf of the Pennsylvania Office of Consumer Advocate.

Cleco Power LLC (Louisiana Public Service Commission Docket No. U-30955), April 2012. Co-authored Report auditing the reasonableness of the fuel costs of Cleco on behalf of the LPSC Staff.

The Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-2012-2292082), May 2012. Presented testimony addressing retainage charges on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-2012-2287044), May 2012. Presented testimony addressing the crediting of asset management arrangement fees and the allocation of capacity costs on behalf of the Pennsylvania Office of Consumer Advocate.

Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-2012-2285985), May 2012. Presented testimony addressing gas cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-2012-2302784), June 2012. Presented testimony addressing the procurement of long-term fixed price gas supplies on behalf of the Pennsylvania Office of Consumer Advocate.

City of Woonsocket Water Division (Public Utilities Commission of Rhode Island Docket No. 4320), June 2012. Presented testimony addressing water cost of service and rate design on behalf of the Division of Public Utilities and Carriers.

UGI Utilities, Inc. – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2012-2302220), July 2012. Presented testimony addressing design peak day forecasting and the assignment of interstate pipeline capacity on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2012-2302221), July 2012. Presented testimony addressing design peak day forecasting and the sharing of capacity release revenues on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2012-2314224); UGI Utilities, Inc. – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2012-2314235); and UGI Central Penn Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2012-2314247), October 2012. Presented testimony addressing Gas Procurement Charges on behalf of the Pennsylvania Office of Consumer Advocate.

Duke Energy Ohio, Inc. (Public Utilities Commission of Ohio Case No. 12-218-GA-GCR), November 2012. Authored report on audit of gas purchasing practices and policies on behalf of the Public Utilities Commission of Ohio.

City of Newport (Public Utilities Commission of Rhode Island Docket No. 4355), December 2012. Presented testimony addressing water cost of service on behalf of Division of Public Utilities and Carriers.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-24), December 2012. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-25), January 2013. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-2012-2328614), January 2013. Presented testimony addressing tariff filing to establish a Gas Procurement Charge on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company, LLC (Pennsylvania Public Utility Commission Docket No. R-2012-2333983), February 2013. Presented testimony addressing tariff filing to establish a Gas Procurement Charge and a Merchant Function Charge on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Gas Works (Pennsylvania Public Utility Commission Docket No. R-2012-2333993), February 2013. Presented testimony addressing tariff filing to establish a Gas Procurement Charge and a Merchant Function Charge on behalf of the Pennsylvania Office of Consumer Advocate.

Chesapeake Utilities Corporation (Delaware Public Service Commission Docket No. 12-450F), March 2013. Presented testimony addressing lost and unaccounted for gas, and the allocation of upstream interstate pipeline capacity on behalf of the Delaware Public Service Commission.

Delmarva Power & Light Company (Public Service Commission of the State of Delaware Docket No. 12-419F), March 2013. Presented testimony addressing interstate pipeline capacity and gas supply contracting practices on behalf of the Delaware Public Service Commission.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-2013-2341534), March 2013. Presented testimony addressing design day forecasting and the allocation of capacity costs on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-26), April 2013. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

Philadelphia Gas Works (Pennsylvania Public Utility Commission Docket No. R-2013-2346376), April 2013. Presented testimony addressing interstate pipeline capacity and gas supply contracting practices on behalf of the Pennsylvania Office of Consumer Advocate.

Peoples Natural Gas, LLC (Pennsylvania Public Utility Commission Docket No. R-2013-2350914), May 2013. Presented testimony addressing retainage charges on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-27), July 2013. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

Citizens Water (Indiana Utility Regulatory Commission Cause No. 44306), July 2013. Presented testimony addressing water cost of service and rate design on behalf of the Indiana Office of Utility Consumer Counselor.

Peoples TWP, LLC (Pennsylvania Public Utility Commission Docket No. R-2013-2355886), July 2013. Presented testimony addressing gas cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Central Penn Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2013-2361764), July 2013. Presented testimony to addressing the contracting for interstate pipeline capacity and the reconciliation of gas costs and revenues on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2013-2361763), July 2013. Presented testimony addressing the reconciliation of gas costs and revenues on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2013-2361771), July 2013. Presented testimony addressing the contracting for interstate pipeline capacity and the reconciliation of gas costs and revenues on behalf of the Pennsylvania Office of Consumer Advocate.

Washington Gas Light Company (Public Service Commission of Maryland Case No. 9322), July 2013. Presented testimony addressing cost of service, rate design and other tariff changes on behalf of the Office of People's Counsel.

CWA Authority, Inc. (Indiana Utility Regulatory Commission Cause No. 44305), August 2013. Presented testimony addressing wastewater cost of service and rate design on behalf of the Indiana Office of Utility Consumer Counselor.

Providence Water Supply Board (Public Utilities Commission of Rhode Island Docket No. 4406), August 2013. Presented testimony addressing water class cost of service and rate design on behalf of the Division of Public Utilities and Carriers.

The York Water Company (Pennsylvania Public Utility Commission Docket No. R-2012-2336379), September 2013. Presented testimony addressing water cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-28), October 2013. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

Nicor Gas Company (Illinois Commerce Commission Docket No. 03-0703), November 2013. Presented testimony addressing the reconciliation of purchase gas costs on behalf of the Citizens Utility Board.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-29), January 2014. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

Delmarva Power & Light Company (Public Service Commission of the State of Delaware Docket No. 13-349F), February 2014. Presented testimony addressing interstate pipeline capacity and gas supply contracting practices on behalf of the Delaware Public Service Commission.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-2014-2399610), March 2014. Presented testimony addressing design day forecasting and the allocation of capacity costs on behalf of the Pennsylvania Office of Consumer Advocate.

Atmos Energy Corporation (Louisiana Public Service Commission Docket No. U-32987), April 2014. Presented testimony addressing modifications to the Company's Rate Stabilization Clause.

Peoples Natural Gas, LLC (Pennsylvania Public Utility Commission Docket No. R-2014-2403939), April 2014. Presented testimony addressing the allocation of interstate pipeline capacity charges and balancing charges on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Gas Works (Pennsylvania Public Utility Commission Docket No. R-2014-2404355), April 2014. Presented testimony addressing the crediting of interstate pipeline capacity release revenues, gas supply put contracts, and the treatment of daily imbalance surcharges and cash-outs on behalf of the Pennsylvania Office of Consumer Advocate.

Chesapeake Utilities Corporation (Delaware Public Service Commission Docket No. 13-351F), May 2014. Presented testimony addressing lost and unaccounted for gas, and the allocation of upstream interstate pipeline capacity on behalf of the Delaware Public Service Commission.

Equitable Gas Company, LLC (Pennsylvania Public Utility Commission Docket No. R-2014-2403935), May 2014. Presented testimony addressing standby charges, balancing charges, and the price-to-compare on behalf of the Pennsylvania Office of Consumer Advocate.

Indiana American Water Company (Indiana Utility Regulatory Commission Cause No. 44450), May 2014. Presented testimony addressing water cost of service and rate design on behalf of the Indiana Office of Utility Consumer Counselor.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43629-GCA-30), May 2014. Presented testimony addressing the assignment and sharing of capacity release revenues, administration of the Company's gas cost incentive mechanism, and gas procurement activity on behalf of the Office of Utility Consumer Counselor.

Chattanooga Gas Company (Tennessee Regulatory Authority Docket No. 07-00224), July 2014. Prepared a report reviewing the Company's performance-based ratemaking mechanism on behalf of the Tennessee Regulatory Authority and Consumer Advocate and Protection Division of the Tennessee Attorney General.

UGI Central Penn Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2014-2420279), July 2014. Presented testimony to addressing affiliated pipeline charges on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Penn Natural Gas, Inc. (Pennsylvania Public Utility Commission Docket No. R-2014-2420273), July 2014. Presented testimony addressing affiliated pipeline charges on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities – Gas Division (Pennsylvania Public Utility Commission Docket No. R-2014-2420276), July 2014. Presented testimony addressing the contracting for interstate pipeline capacity and the reconciliation of gas costs and revenues on behalf of the Pennsylvania Office of Consumer Advocate.

OCA Statement No. 3-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
)
v.) Docket No. R-2015-2468056
)
COLUMBIA GAS OF)
PENNSYLVANIA, INC.)

REBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

July 16, 2015

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EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

OCA Stmt. 3-R
R-2015-2468056
8-4-15
Harrisburg JS

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President with Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement No. 3.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain issues addressed in the direct testimony of Pennsylvania State University ("PSU") witness James L. Crist; Office of Small Business Advocate ("OSBA") witness Robert D. Knecht; and Bureau of Investigation and Enforcement ("I&E") witness Jeremy B. Hubert.

II. PSU WITNESS JAMES L. CRIST

Q. PLEASE SUMMARIZE WITNESS CRIST'S RECOMMENDATIONS CONCERNING THE PROPOSED INCREASE ASSIGNED TO THE LARGE DISTRIBUTION SERVICE ("LDS") CLASS.

A. Witness Crist explains that Columbia has proposed to increase the rates of the LDS class by $2,447,109, or 15.1 percent. He notes that about half (47.2 percent) of the LDS customers are flex rate customers that will not be assigned any portion of the increase, and the proposed increase will be borne entirely by non-flex rate LDS customers. Witness Crist claims that this will produce an excessively large increase for non-flex rate LDS customers. He also claims that flex rate customers are making a positive contribution to revenues and, for this reason, the increase the Company has allocated to flex rate LDS customers should be allocated to all non-competitive customers of all classes. Witness Crist recommends that the LDS class only be assigned 52.8 percent of the Company's proposed increase, and the remainder should be allocated to the non-competitive customers in other classes, except the Main Line rate classes.

Q. SHOULD WITNESS CRIST'S RECOMMENDATION CONCERNING THE INCREASE ASSIGNED TO NON-FLEX RATE LDS CUSTOMERS BE ADOPTED?

A. No, for several reasons. First, as explained in my direct testimony, the revenue increase authorized by the Commission in this proceeding should be guided by the results of a cost of service study utilizing the Peak & Average method. Under the Peak & Average method, the relative rate of return of the LDS rate class at current rates is negative, indicating that the LDS class is providing a revenue contribution that is significantly below the indicated cost of service. Under witness Crist's proposal, non-flex rate LDS customers would receive an increase comparable to the overall system average increase. A rate class providing a revenue contribution that is significantly below the indicated cost of service should receive an increase much greater than the system average increase.

Second, the increase proposed for the LDS rate class is not excessively large under the Company's proposal or under the OCA's proposed revenue distribution. Under the OCA's proposed revenue distribution, the average increase for the Residential rate class is $0.90 per Mcf, and the $3,056,047 increase proposed by the OCA for the LDS rate class reflects an average increase of $0.16 per Mcf. After accounting for flex rate customers, the average increase proposed by the OCA for non-flex LDS rate customers is $0.32 per Mcf. The average per-Mcf increases for the LDS rate class would be less under the Company's proposed revenue distribution.

Finally, the notion that the increase the Company has allocated to non-competitive LDS customers should be allocated to all non-competitive customers of all classes should be rejected. Under witness Crist's proposal, the rate discounts granted to LDS customers would be largely absorbed by the Residential and Small General rate classes, even though no Residential and very few Small General customers receive rate discounts. It is not appropriate for Residential and Small General customers to share in the costs of these discounted rates since these discounts are largely limited to the Large Commercial and Industrial classes. Given the Commission's policy on similar matters, the effect of rate discounting should stay within each class. For example, the Commission has ruled that the Residential class must be responsible for 100 percent of the cost burden of operating and maintaining Columbia's Customer Assistance Program ("CAP") costs because Residential customers are the only class that qualifies for such discounted rates. Similarly, LDS, SDS, and mainline customers are the only customers that enjoy discounted rates and the revenue deficiency associated with these discounts should remain within these classes.

III. OSBA WITNESS ROBERT D. KNECHT

Q. PLEASE DESCRIBE WITNESS KNECHT'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING.

A. Witness Knecht's proposed distribution of the revenue increase authorized in this proceeding is based on a 75 percent weighting of the Company's Peak & Average allocated cost of service study ("ACOSS") and a 25 percent weighting of the Company's Customer/Demand ACOSS study. Witness Knecht's 75/25 percent weighted ACOSS results are presented in Exhibit IEc-2, and indicate that the Residential class provides a cross-subsidy of $2.8 million and the Small General Service ("SGS") class provides a cross-subsidy of $3.2 million. Therefore, witness Knecht has proposed that the first $6.0 million reduction to the Company's proposed $46.1 million increase be equally split between the Residential and SGS rate classes. Any further reduction to the Company's proposed increase would be applied using a proportional scale-back approach.

Q. IS WITNESS KNECHT'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED IN THIS PROCEEDING REASONABLE?

A. No, it is not. As just explained, the revenue increase authorized by the Commission in this proceeding should be guided by the results of a cost of service study prepared utilizing the Peak & Average method. Witness Knecht's proposed distribution is improperly and unreasonably weighted 25 percent based on the Company's Customer/Demand ACOSS.

Q. WITNESS KNECHT CLAIMS THAT THE FULLY LOADED CUSTOMER COST IN HIS 75/25 PERCENT WEIGHTED ACOSS SUPPORTS A RESIDENTIAL CUSTOMER CHARGE OF $24.37. WHAT IS YOUR RESPONSE?

A. Although witness Knecht is not recommending that the Residential customer charge be increased to $24.37, I would note that his calculated charge includes a customer component of distribution mains. As explained in my direct testimony, the allocation of a portion of distribution mains investment based on the number of customers is improper, unreasonable, and has consistently been rejected by this Commission.

Q. WHAT IS WITNESS KNECHT'S POSITION CONCERNING COLUMBIA'S SERVICE EXPANSION PROPOSALS?

A. Witness Knecht does not oppose Columbia's service expansion proposals, but claims that in at least some cases, new customers taking service under the proposals will be subsidized by existing customers, and the Commission should recognize this if it chooses to adopt Columbia's proposal.

Q. WHAT IS YOUR RESPONSE TO WITNESS KNECHT'S COMMENTS?

A. Witness Knecht points out that in some cases, an expansion customer may contribute less revenue than the incremental costs of serving that customer. However, the Commission should also recognize that in other cases, an expansion customer may contribute more revenue than the incremental costs of serving that customer, and this would benefit all customers on the Columbia system.

IV. <u>I&E WITNESS JEREMY B. HUBERT</u>

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT THE COMPANY'S CUSTOMER/DEMAND ACOSS BE REJECTED BY THE COMMISSION, AND THAT THE DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING BE BASED ON A PEAK & AVERAGE ACOSS. IS WITNESS HUBERT IN AGREEMENT WITH THIS APPROACH?

A. Yes, he is.

Q. PLEASE DESCRIBE WITNESS HUBERT'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED IN THIS PROCEEDING.

A. Under the Peak & Average ACOSS supported by witness Hubert, the Residential class is providing revenues significantly in excess of the indicated cost of service. Therefore, witness Hubert is recommending that the Company's proposed revenue distribution be adjusted by reallocating $3.5 million from the Residential class to the SGSS/SCD/SGDS and SDS/LGSS rate classes. If the Commission authorized less than the full increase requested by the Company, witness Hubert generally recommends that approximately 80 percent of the reduction be assigned to the Residential class, and approximately 20 percent be assigned to the SGSS/SCD/SGDS rate classes.

Q. WHAT IS YOUR RESPONSE TO WITNESS HUBERT'S PROPOSED REVENUE DISTRIBUTION AND SCALEBACK?

A. Witness Hubert's proposed revenue distribution and scaleback produces results over the potential range of increases that are authorized by the Commission that are fairly consistent with the proposed revenue distribution and scaleback proposed in my direct testimony. Therefore, witness Hubert's proposals appear reasonable.

Q. WITNESS HUBERT RECOMMENDS THAT THE RESIDENTIAL CUSTOMER CHARGE BE INCREASED FROM $16.75 TO $16.93. WHAT IS YOUR RESPONSE?

A. Witness Hubert's proposed customer charge of $16.93 was calculated consistent with the Residential customer charge calculation presented in my direct testimony of $17.13. Both Mr. Hubert and I calculated our proposed customer charges based on CPA's requested revenue increase. In my direct testimony, I noted that at the revenue increase authorized by the Commission in this proceeding, a cost-based customer charge would certainly be less than the current charge of $16.75 and, therefore, the current charge should be maintained. At the revenue increase authorized by the

Commission in this proceeding, witness Hubert's calculated Residential customer charge would also certainly be less than the current charge and, therefore, the $16.75 charge should be maintained.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Rebuttal Testimony, OCA St. No. 3-R, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
Suite 300
10480 Little Patuxent Parkway
Columbia, MD 21044

DATED: July 14, 2015

OCA Statement No. 3-S

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
)
v.) Docket No. R-2015-2468056
)
COLUMBIA GAS OF)
PENNSYLVANIA, INC.)

SURREBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

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July 28, 2015

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

OCA Stmt. 3-S
R-2015-2468056
8-4-15
Harrisburg JS

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President with Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement No. 3, and my rebuttal testimony was submitted as OCA Statement No. 3-R.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to certain issues addressed in the rebuttal testimonies of Columbia Gas of Pennsylvania ("Columbia") witnesses Brian E. Elliott, Mark Balmert, and Robert C. Waruszewski; Office of Small Business Advocate ("OSBA") witness Robert D. Knecht; and Bureau of Investigation & Enforcement ("I&E") witness Christopher Keller.

II. COLUMBIA GAS OF PENNSYLVANIA

Witness: Brian E. Elliott

Q. BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY CONCERNING THE COST OF SERVICE METHODOLOGY THAT SHOULD BE RELIED UPON FOR REVENUE DISTRIBUTION PURPOSES IN THIS PROCEEDING.

A. In my direct testimony I recommended that the Peak & Average cost of service methodology should be relied upon in this proceeding for revenue distribution purposes. Under this method, 50 percent of distribution mains investment is allocated based on annual throughput and 50 percent is allocated based on design day (peak) demands.

Q. WHAT IS WITNESS ELLIOTT'S RESPONSE TO YOUR RECOMMENDATION?

A. Witness Elliot claims that "customer throughput consumption has absolutely no impact on the determinations of the size, length, or cost of the distribution mains the customer is connected to" (page 5, line 22 through page 6 line 2). Therefore, he contends that no portion of distribution main investment should be allocated based on throughput.

Q. DO YOU AGREE WITH WITNESS ELLIOTT THAT NO PORTION OF DISTRIBUTION MAINS INVESTMENT SHOULD BE ALLOCATED BASED ON THROUGHPUT?

A. No. As explained in my direct testimony, the basic reason why NGDCs like Columbia invest in their distribution systems is to meet the annual demands for gas by end-use customers. This is the reason for the existence of the NGDC in the first place. Without sufficient annual gas usage over which to amortize the annual costs of providing service, there would be no gas distribution system. That is, there would be no distribution mains or customers connected to them.

In addition, under Columbia's current mains extension policy, also described in my direct testimony, annual demands and the associated revenues is the primary factor considered in Columbia's main extension investment decision-making process. Therefore, throughput consumption absolutely has an impact on Columbia's distribution mains investment.

Q. WITNESS ELLIOTT PRESENTS AN ANALYSIS THAT HE CLAIMS DEMONSTRATES THAT THERE IS A CORRELATION BETWEEN FOOTAGE OF MAINS PIPE AND CUSTOMER COUNTS, AND AN ANALYSIS THAT INDICATES A NEGATIVE CORRELATION BETWEEN THE FOOTAGE OF MAINS AND THROUGHPUT. WHAT IS YOUR RESPONSE?

A. Witness Elliott utilizes these analyses to support his claim that the number of customers is a factor upon which distribution mains investment should be allocated and that throughput should not be a factor. However, witness Elliott's analyses are inconsistent with reality. His analyses suggest that when Columbia adds a customer, throughput decreases, implying that the customer which Columbia added has negative usage. Under Columbia's current mains extension policy, Columbia would not add a customer with negative usage, and no such customers even exist and, therefore, witness Elliott's analyses should be given no consideration.

In addition, in this proceeding, parties have proposed allocations of distribution mains investment on a combination of three factors: number of customers; throughput; and design day demands. An analysis of footage of mains and design day demands, which I performed, also reveals a negative correlation (R Square of 0.8940). That is, as the footage of mains increases, the design day demands of the Columbia system decrease. Following witness Elliott's logic, because throughput and design day demand do not increase as footage of mains increase, this would suggest that distribution mains investment should be allocated entirely on the number of customers. Such an allocation would be unreasonable, and I am not aware of such an allocation being accepted by a commission in any jurisdiction or recommended in any cost allocation manual.

Q. WITNESS ELLIOTT CLAIMS THAT IN APPROVING THE PEAK & AVERAGE METHOD IN THE 1994 NATIONAL FUEL GAS DISTRIBUTION CORPORATION ("NFGD") BASE RATE PROCEEDING AT DOCKET NO R-00942991, NFGD ONLY PRESENTED COST OF SERVICE STUDIES USING THE PEAK & AVERAGE METHOD AND, THEREFORE, THE COMMISSION WAS IN NO WAY MAKING A STATEMENT ABOUT THE APPLICABILITY OF A STUDY WHICH ALLOCATES MAINS INVESTMENT PARTIALLY ON THE BASIS OF THE NUMBER OF CUSTOMERS. WHAT IS YOUR RESPONSE?

A. As I explained in my direct testimony, in Philadelphia Gas Works, Docket No. R-0006931, 2007 Pa. PUC Lexis 46(2007), the Commission found that mains allocations based on the number of customers were not acceptable. Moreover, witness Elliott overlooks that, in its Order in the NFGD proceeding, the Commission found:

> The Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation which should remain intact.

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS IN YOUR DIRECT TESTIMONY THAT COLUMBIA'S CUSTOMER/DEMAND STUDY DID NOT PROPERLY CONSIDER CUSTOMER DEMANDS THAT CAN BE MET FROM A 2-INCH MAIN WHEN DETERMINING THE ALLOCATION OF THE DEMAND-RELATED PORTION OF DISTRIBUTION MAINS.

A. Columbia's Customer/Demand study utilized a minimum-sized unit approach to determine the customer component of distribution mains investment. More specifically, Columbia's minimum-sized system was based on the hypothetical costs associated with a 2-inch distribution main system, and it is these costs which were allocated based on the number of customers. Under this approach, as shown on Table 1 of my direct testimony, Columbia's minimum system represents approximately 50 percent of total mains investment. In my direct testimony, I noted that all (or nearly all) Residential customers design day demands could be met through the 2-inch minimum system. This being the case, I noted that there would be little to no unmet Residential gas service requirements that would be dependent upon demand-related pipe costs. That is, the minimum system portion of distribution mains would be sufficient to meet the design day demands of Residential customers and, therefore, it would be inappropriate to allocate any additional portion of distribution mains that is allocated based on design day demands to Residential customers.

Q. WHAT IS WITNESS ELLIOTT'S RESPONSE TO YOUR CLAIM?

A. Witness Elliott agrees that all (or nearly all) Residential customers could be provided service through the minimum system. However, he claims that there is no evidence to suggest that the Residential class' proportionate share of the capacity of the 2-inch minimum system is any different from that class' proportionate share of the entire distribution system.

Q. WHAT IS YOUR RESPONSE TO WITNESS ELLIOTT?

A. Witness Elliott's agreement that all Residential customers could be provided service through the 2-inch minimum system is based on an analysis performed by witness Balmert. In performing that analysis, witness Balmert found that the 2-inch minimum system would be capable of serving all Residential customers with an annual demand of 1,165.4 Mcf per year or less. He notes that virtually all Residential customers use less than 1,165.4 Mcf per year. Therefore, witness Balmert concludes that all Residential customers could be served by the minimum system. Certainly the share of Residential customers using less than 1,165.4 Mcf per year is greater than the share in other rate classes. For example, the average usage per customer for the LDS/LGSS rate class is 194,249 Mcf per year and for the SDS/LGSS rate class average usage is 14,702 Mcf per year. Therefore, the proportionate share of demands being met by the minimum system for Residential is much greater than that of other rate classes.

III. COLUMBIA GAS OF PENNSYLVANIA

Witness: Mark Balmert

Q. WITNESS BALMERT CRITICIZES I&E WITNESS HUBERT'S MONTHLY RESIDENTIAL CUSTOMER CHARGE CALCULATION BECAUSE HE REMOVED CERTAIN ACCOUNTS FROM THE CALCULATION PREPARED BY THE COMPANY. DO YOU HAVE ANY COMMENTS?

A. Yes. My monthly Residential customer charge calculation also removed some of the same accounts from the calculation prepared by the Company. The approach I used to calculate a monthly Residential customer charge is generally based on the method approved by the Commission in a PPL Gas Utilities Corp. rate case. Pa. PUC v. PPL Gas Utilities Corp., 2007 Pa. PUC LEXIS 2 (2007).

Q. WITNESS BALMERT PRESENTS AN ELABORATE ANALYSIS WHICH HE CLAIMS DEMONSTRATES THAT OTHER NGDCS IN PENNSYLVANIA HAVE A HIGHER LEVEL OF FIXED-COST RECOVERY THAN COLUMBIA'S RATES IN AN ATTEMPT TO DEMONSTRATE THAT ITS RESIDENTIAL MONTHLY CUSTOMER CHARGE IS REASONABLE. WHAT IS YOUR RESPONSE?

A. Witness Balmert's analysis includes the recovery of fixed-costs through volumetric charges and, therefore, is not an appropriate basis of comparison of customer charges, In addition, witness Balmert's analysis, whether accurate or not, is not presented on monthly Residential customer bills. Therefore, his analysis would do little to satisfy customer concerns that Columbia has the highest monthly Residential customer charge in the Commonwealth.

IV. <u>OFFICE OF SMALL BUSINESS ADVOCATE</u>

Witness: Robert D. Knecht

Q. BRIEFLY SUMMARIZE COLUMBIA'S PROPOSAL IN THIS PROCEEDING CONCERNING THE SUB-FUNCTIONALIZATION AND ALLOCATION OF DISTRIBUTION MAINS COSTS, YOUR DIRECT TESTIMONY ADDRESSING COLUMBIA'S PROPOSAL, AND WITNESS KNECHT'S VIEW OF YOUR RECOMMENDATION.

A. In my direct testimony I explained that, excluding the MLS/MLDS rate class, Columbia assigned the original cost of distribution mains investment to three categories: (1) Low Pressure; (2) Regulated Non-Low Pressure; and (3) Remaining Regulated Pressure. Each of these categories was then separately allocated to rate class under the Company's Customer/Demand, Peak and Average, and Average ACOS Studies. I recommended that Columbia's sub-functionalization of distribution mains investment be rejected because it failed to consider the net investment of each distribution mains category, and rates in this proceeding will be set based on net investment, not original costs. Witness Knecht believes that Columbia's sub-functionalization of distribution mains investment is a modest step in the right direction, but that more progress needs to be made in matching mains costs and customers.

Q. WHAT IS YOUR RESPONSE TO WITNESS KNECHT'S OBSERVATIONS CONCERNING THE SUB-FUNCTIONALIZATION OF MAINS?

A. Without knowing the results of an analysis of the sub-functionalization of distribution mains investment based on net investment, it is unknown whether the results of Columbia's approach or the approach I have proposed is more reasonable or accurate. Therefore, there is no basis for concluding that Columbia's approach is more reasonable or accurate.

In addition, I would note that in the 1994 NFGD base rate proceeding referenced earlier in my surrebuttal, NFGD had proposed to separately assign the costs associated with large and small mains, a proposal similar to Columbia's sub-functionalization of distribution mains in this proceeding. The Commission rejected NFGD's proposal in its Order in that base rate proceeding.

Q. WITNESS KNECHT NOTES THAT THE COMMISSION HAS PREVIOUSLY APPROVED THE USE OF THE MINIMUM SYSTEM APPROACH WITH A CUSTOMER COMPONENT FOR ELECTRIC DISTRIBUTION COMPANIES ("EDC"). WHAT IS YOUR RESPONSE?

A. Witness Knecht has failed to recognize that the mains extension policies of NGDCs like Columbia are different from the line extension policies of EDCs. For example, one of the EDCs to which witness Knecht is referring to as precedent setting is PPL Electric Utilities Corporation ("PPL Electric"). PPL Electric constructs line extensions to supply service in residential, commercial or industrial developments in specific areas with revenue guarantees based on the number of customers which the

Company knows are to be served in the development within two years of initial construction.[1] The total revenue guarantee for a line extension is divided among the customers to be supplied initially from the line extension to determine the total amount to be guaranteed per customer, which is then divided by the number of years in the initial term of the contract to determine the customer's annual guarantee.[2] Thus for an EDC like PPL Electric, line extension decisions and cost responsibility are determined on a per-customer basis, but for an NGDC like Columbia, main extension decisions and cost responsibility are determined based largely on annual volumes. Electric service must be extended to customers that request service regardless of usage because there are no viable alternatives. There are a number of viable alternatives to natural gas service including fuel oil, propane, and electricity, and service is not currently extended unless annual usage is sufficient to justify the extension of service.

Q. WHAT IS WITNESS KNECHT'S RESPONSE TO YOUR CLAIM THAT NON-RESIDENTIAL CUSTOMERS ARE "TYPICALLY LOCATED FARTHER APART THAN RESIDENTIAL CUSTOMERS."

A. Witness Knecht does not disagree with my claim but indicates that I offer no specific evidence. He then claims that small and medium sized businesses may be located in concentrated commercial areas such that the density for those customers is actually higher than that for Residential customers. However, he presents no evidence of the extent to which the concentrated commercial areas exist in Columbia's service territory or the density for those customers.

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[1] PPL Electric Tariff, 4th Revised page no. 7A.

[2] PPL Electric Tariff, 9th Revised page no. 7B.

Q. WITNESS KNECHT CLAIMS THAT YOUR PEAK & AVERAGE COST ALLOCATION DOES NOT PROPERLY REFLECT ECONOMIES OF SCALE OR PER-UNIT DECLINING COSTS FOR DISTRIBUTION MAINS. DOES THE PEAK & AVERAGE METHOD INDICATE DECLINING PER-UNIT COSTS FOR COLUMBIA'S LARGER CUSTOMER CLASSES?

A. Yes. Table 1 shows the declining per-unit allocated distribution mains costs for Columbia's larger customer classes under the OCA's Peak & Average ACOS, excluding the MLS/MLDS class.

Table 1
Per-unit Allocated Mains Costs

Rate Class	Annual Demand (Mcf)	Unit Costs
RSS/RDS	33,927,676	$19.37
SGSS/SCD/SGDS	15,162,538	$18.14
SDS/LGSS	6,865,950	$15.57
LDS/LGSS	19,424,858	$10.74

V. BUREAU OF INVESTIGATION & ENFORCEMENT

Witness: Christopher Keller

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY WITH RESPECT TO COLUMBIA'S NPV CALCULATION FOR NEW FACILITY EXTENSIONS?

A. In my direct testimony, I suggested that Columbia's NPV calculation for the extension of new facilities be modified to include a 5 percent annual revenue escalation factor.

Q. DOES WITNESS KELLER AGREE WITH YOUR RECOMMENDATION?

A. No, he does not. Witness Keller claims that any future increases in base rates will be needed to recover future increases in expenses and would have no effect on the NPV calculation. He also claims there is no basis for a five percent revenue escalation factor.

Q. WHAT IS YOUR RESPONSE TO WITNESS KELLER?

A. I would agree with witness Keller that a portion of future increases in base rates will be needed to recover future increases in expenses. However, future increases in base rates will also be needed to recover the costs associated with additional facility investment. Once Columbia extends its facilities to serve a new customer, typically no new investment would be required to specifically continue serving the new customer. Therefore, a portion of future increases in base rate revenues should be included in the NPV calculation.

With respect to the 5 percent revenue escalation factor, over the past six to seven years, Columbia's base rates have increased approximately 90 percent. This reflects an increase of 13 to 15 percent per year, and justify the 5 percent escalation factor.

VI. COLUMBIA GAS OF PENNSYLVANIA

Witness: Robert C. Waruszewski

Q. WITNESS WARUSZEWSKI ALSO DISAGREES WITH YOUR PROPOSAL TO INCLUDE A FIVE PERCENT REVENUE ESCALATION FACTOR IN THE COMPANY'S NPV ANALYSIS. WHAT IS THE BASIS FOR HIS DISAGREEMENT?

A. Witness Waruszewski claims that future rate increases do not fit the category of incremental revenue because these increases cover the Company's costs to maintain service, and Columbia would incur these increases even if the potential customers do not connect to Columbia's system.

Q. WHAT IS YOUR RESPONSE TO WITNESS WARUSZEWSKI?

A. My response to witness Waruszewski is generally the same as my response to I&E witness Keller. In addition, while Columbia would incur additional costs to maintain its system even if potential customers do not connect to its system, Columbia will realize incremental revenues from the new customers which would not be realized if the new customers did not connect to Columbia's system. Therefore, these incremental revenues should be reflected in the NPV calculation.

Q. COLUMBIA GENERALLY AGREES WITH THE REPORTING REQUIREMENTS YOU RECOMMENDED IN CONJUNCTION WITH THE PROPOSED SERVICE EXPANSION PROPOSALS. HOWEVER, WITNESS WARUSZEWSKI CLAIMS TWO OF THE REQUIREMENTS ARE PROBLEMATIC. WHAT IS YOUR RESPONSE TO WITNESS WARUSZEWSKI?

A. I believe the concerns expressed by witness Waruszewski are reasonable and would be willing to accept these modifications to the service expansion reporting requirements.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 3-S, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
Suite 300
10480 Little Patuxent Parkway
Columbia, MD 21044

DATED: July 28, 2015

OCA Statement No. 4

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
v.	)	Docket No. R-2015-2468056
	)	
COLUMBIA GAS OF PENNSYLVANIA, INC.	)	

DIRECT TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 19, 2015

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SECRETARY'S BUREAU

OCA Stmt. 4
R-2015-2468056
8-4-15
Harrisburg 26

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger Colton. My business address is 34 Warwick Road, Belmont, MA 02478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving telephone, water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate (OCA).

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of New York, Pennsylvania, Michigan, Illinois and Iowa, as well as in the provinces of Ontario, Manitoba and British Columbia. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Iowa Department of Human Rights), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., Energy Outreach Colorado, Community Action Partnership Association of Idaho), and private utilities (e.g., Unitil Corporation d/b/a Fitchburg Gas and Electric Company, Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state- and utility-specific work, I engage in national work throughout the United States. For example, I am presently working with a team for the Water Research Foundation to assess how to extend customer service initiatives to "hard to reach" customers for municipal water utilities. In 2011, I worked with the U.S. Department of Health and Human Services (the federal LIHEAP office) to advance the review and utilization of the Home Energy Insecurity Scale as an outcomes measurement tool for LIHEAP. In 2010, I completed (as one member of a team) work on a national study of the responses of water utilities to the payment troubles of residential customers for the U.S. Environmental Protection Agency and the Water Research Foundation. In 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (regulatory economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues as set forth in Appendix A.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission (PUC or Commission) on numerous occasions regarding utility issues affecting low-income customers. I have also testified in regulatory proceedings in more than 30 states and various Canadian provinces on a wide range of low-income utility issues as set forth in Appendix A. More specifically, I have testified before this Commission in Columbia Gas proceedings involving rate design and universal service issues in 2014, 2013, 2010, 2008, 1999, 1991 and 1990.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is as follows:

- First, I examine the reasonableness of the Columbia Gas of Pennsylvania (CGPA or Company) proposed increase in its residential customer charge. I find that the Company's proposal will disproportionately adversely affect low-income customers, whether or not those customers participate in the Company's Customer Assistance Program (CAP). I find further that the proposed customer charge increase will increase costs to both low-income customers and non-low-income customers of CGPA.

- Second, I examine certain aspects of universal service cost recovery sought by Columbia Gas. I find that the Company should be restricted in the extent to which it can collect in-house administrative costs through its Universal Service Rider. I conclude further that the Company's proposal to collect costs for its Emergency Repair Program (ERP) is reasonable.

Part 1. CGPA Increase in Residential Customer Charge.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I discuss the increased costs imposed on residential customers because of the proposed rate increase and change in rate design. The Company proposes to increase its customer charge from $16.75 to $20.60 per month. (CGPA Statement 11, page 14).

A. Importance of Customer Charge to Low-Income Customers.

Q. ARE LOW-INCOME CUSTOMERS PROTECTED FROM THE RATE INCREASES SOUGHT BY CGPA IN THIS PROCEEDING?

A. No. CGPA witness Balmert errs when he asserts that participants in the Company's Customer Assistance Program (CAP) will receive no rate increase as a result of this rate proceeding. (CGPA Statement 11, page 14). And even to the extent that some CAP customers are protected, the vast majority of CGPA's low-income customers are not CAP participants.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT CAP CUSTOMERS ARE NOT A PRIORI PROTECTED FROM THE RATE INCREASES PROPOSED IN THIS PROCEEDING.

A. While CGPA has a percentage of income component in its CAP program, it also has other payment components that are not tied to a percentage of income. Under a percentage of income plan, CAP participants would be insulated from an increase in unaffordability resulting from the Company's proposed rate increases and rate design changes. Under the other CAP program components, however, customers are not insulated from increasing rates. Indeed, according to the Company's most recent CAP evaluation (2010), only 20% of CGPA's CAP participants are enrolled in the CGPA percentage of income plan (PIP). At the same time, 43% are enrolled in the payment plan where customers are billed the average of their last 12 months of payment, while 30% are enrolled in the Company's percentage of bill program (50% of an equal monthly payment plan). Nearly three-fourths (73%) of CGPA's CAP customers, in other words, will be adversely affected by the Company's proposed increased rates and change in rate design.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR STATEMENT THAT EVEN TO THE EXTENT THAT SOME CAP CUSTOMERS MAY BE PROTECTED, MOST LOW-INCOME CUSTOMERS DO NOT PARTICIPATE IN CAP.

A. In 2013, CGPA had 95,543 estimated low-income customers. Of that population, CGPA reported a "confirmed" low-income population of 67,711 customers. "Confirmed low-income" is a term-of-art used for purposes of reporting to the PUC's Bureau of Consumer Services (BCS). Two observations are important in this number.

- First, the Company has identified only 70% of its estimated low-income population base (67,711 / 95,543 = 70.9%). Moreover, since 2004, the absolute number of confirmed low-income customers has declined by nearly 2,500 customers. The decrease in confirmed low-income customers has occurred despite the fact that the number of estimated low-income customers has increased by 23,000.
- Second, as can be seen below, with a 2013 CAP participation of 20,103, less than 30% of confirmed low-income customers, and only one-in-five estimated low-income customers, have enrolled in CGPA's CAP. A relatively small proportion of the confirmed low-income population base, in other words, receives the affordability protections of CAP. Since 2008, the number of CGPA CAP participants has declined by 20%, despite the fact that the number of estimated low-income customers continues to climb. The percentage of estimated low-income CGPA customers participating in CAP has declined to the lowest level since 2001.

CGPA	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Estimated LI	72,584	70,038	59,704	70,038	70,038	89,682	89,445	94,619	95,303	95,543
Confirmed LI	70,038	60,377	59,703	60,847	62,707	69,927	66,307	67,688	67,391	67,711
Pct conf'd of estimated LI	96.5%	86.2%	100.0%	86.9%	89.5%	78.0%	74.1%	71.5%	70.7%	70.9%
CAP	19,259	21,864	24,106	23,604	24,675	25,201	22,606	22,314	20,026	20,103
Pct CAP of estimated LI	27%	31%	40%	34%	35%	28%	25%	24%	21%	21%
Pct CAP of confirmed LI	27%	36%	40%	39%	39%	36%	34%	33%	30%	30%

Q. ARE ALL LOW-INCOME CUSTOMERS ELIGIBLE TO PARTICIPATE IN CAP?

A. No. CAP eligibility extends to customers who have income at or below 150% of the Federal Poverty Level. A significant number of households in the counties served by CGPA, however, live with income that just exceeds the CAP eligibility limit. Of the total number of households living with income at or below 200% of Poverty, 70% live with income below 150% of Poverty Level, while 30% live with income between 150% and 200% of Poverty. This higher income level provides inadequate income to meet basic needs, but households with these incomes do not qualify for CGPA's CAP program.

Q. DOES THE EXPOSURE TO INCREASED BILL UNAFFORDABILITY FOR LOW-INCOME CUSTOMERS ALSO HAVE A FINANCIAL IMPACT ON OTHER CUSTOMERS?

A. Yes. The proposed increase in the customer charge imposes disproportionately high rate increases on low-use customers, whether low-income or non-low-income. Low-use customers in the CGPA service territory, however, tend also to be low-income customers. As a result, through its increased customer charge, the Company proposes to increase rates the most for those who can least afford to pay those rate increases. Not only are proportionately more confirmed low-income customers in arrears, but those who are in arrears, are *deeper* in arrears. CGPA proposes to respond to these circumstances by *raising* rates the most to these customers. The resulting increase in bad debt, working capital, and credit and collection costs will be borne by all ratepayers.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT LOW-INCOME CUSTOMERS HAVE A DISPROPORTIONATE PAYMENT-TROUBLED STATUS.

A. The PUC's Bureau of Consumer Services (BCS) publishes an annual report on Universal Service Programs and Collections Performance. That annual BCS report differentiates collections performance based on "confirmed low-income customers" and on all residential customers.[1] According to the most recent BCS report, CGPA's confirmed low-income customers exhibit greater payment difficulties than residential customers generally. Confirmed low-income customers, among other things: (1) have a proportionately greater number of customers in arrears; (2) have a proportionately greater number of dollars in arrears; and (3) have a higher dollar level of arrears.

As one example of the collections performance between low-income customers and all residential customers, the percentage of CGPA customers in arrears, along with the average level of arrears, was as follows for 2013, the most recent data published by BCS (published in November 2014):

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[1] The BCS comparison is *not* between confirmed low-income customers and *non*-low-income customers. It is between confirmed low-income customers and *all* residential customers (a population that includes the confirmed low-income group as one of its component parts).

Confirmed Low-Income vs. All Residential (CGPA) (2013)

	Percentage Customers in Debt		Average Arrears	
	All Residential	Confirmed Low-Income	All Residential	Confirmed Low-Income
CGPA	7.8%	19.7%	$342.98	$442.67

Confirmed low-income customers are in arrears at more than twice the rate of residential customers as a whole. Moreover, they have an arrearage balance that is 30% greater than the overall residential population.

There can be no question that CGPA's confirmed low-income customers face disproportionate payment difficulties. The data below compares the percentage of total customers represented by confirmed low-income customers to the percentage of total customers in debt represented by those confirmed low-income customers. While confirmed low-income customers represent 17.6% of all CGPA residential customers, they represent 44.3% of all of CGPA's customers in arrears.

Confirmed Low-Income: Percentage of All Customers vs. Percentage of Customers in Arrears (CGPA) (2013)

	LI Percentage of All Residential Customers	LI Percentage of Residential Customers in Arrears
CGPA	17.6%	44.3%

Q. ARE THERE CUSTOMERS WHO ARE LIKELY TO BE LOW-USE CUSTOMERS WHETHER OR NOT THEY ARE LOW-INCOME?

A. The elderly and disabled, in particular, will more likely be low use customers who will be harmed by CGPA's proposed increase in the customer charge. The elderly and disabled disproportionately tend to live in small households. According to the U.S. Department of

Energy's Residential Energy Consumption Survey (RECS), lower natural gas consumption is associated with smaller household sizes. RECS reports that as a household adds each new member, natural gas consumption increases.

Number of Household Members	Mcf Gas Usage (Northeast)
1 Person	56
2 Persons	76
3 Persons	80
4 Persons	92
5 Persons	102
6 or More Persons	110

Imposing a disproportionate rate increase on these aging and disabled customers has a particular adverse impact on these customers. The aging and disabled are customers who are most likely to have fixed incomes. Their incomes do not noticeably increase from year-to-year. As a result, the aging and disabled are customers who are least likely to be able to absorb rate increases in their annual household budgets.

B. Income and Usage Levels.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the relationship between income and the level of natural gas consumption. I find that low-income status is positively associated with low-usage status. As a result, the proposed increase in the fixed monthly customer charge will have a disproportionately adverse impact on the affordability of energy to low-income customers.

Q. DOES LOW-INCOME USAGE DIFFER FROM THAT OF RESIDENTIAL CUSTOMERS GENERALLY?

A. Yes. While low-income households tend to have less efficient energy consumption than do residential customers generally on a per square foot of housing basis, because they live in much smaller housing units, they tend to have lower overall natural gas consumption. The most recent data published by the U.S. Department of Energy (DOE) in its 2009 Residential Energy Consumption Survey (RECS) shows the following for total energy usage in the Northeast (RECS, Table CE1.2).

2009 Annual Household Income	**Per Square Foot** (thousand Btu)	**Per Household** (million Btu)
Less than $20,000	65.0	83.3
$20,000 to $39,999	56.3	98.2
$40,000 to $59,000	49.8	98.9
$60,000 to $79,999	48.4	99.9
$80,000 to $99,999	48.4	119.2
$100,000 to $119,999	42.4	131.1
$120,000 or More	45.9	154.8

The same results appertain when the examination is limited exclusively to natural gas. According to the DOE's RECS (Table CE2.2), in the Northeast, the region of which Pennsylvania is a part, as incomes increase, natural gas usage increases correspondingly.

2009 Annual Household Income	mmBtu	MCF
Less than $20,000	58.7	57
$20,000 to $39,999	76.5	75
$40,000 to $59,000	69.7	68
$60,000 to $79,999	70.7	69
$80,000 to $99,999	81.2	79
$100,000 to $119,999	92.7	90
$120,000 or More	114.4	112

It does not matter which end-use is being examined. As income increases, so, too, does energy usage increase. The average household data by-end-use, in million BTU, for Northeast households using the end-use (RECS, Table CE3.2) is presented immediately below.

Consumption by End-Use (mmBtu) (Northeast)

2009 Annual Household Income	Total	Space Heating	Water Heating
Less than $20,000	83.3	51.2	12.5
$20,000 to $39,999	98.2	57.2	16.4
$40,000 to $59,000	98.9	55.1	16.1
$60,000 to $79,999	99.9	55.1	16.5
$80,000 to $99,999	119.2	64.0	19.0
$100,000 to $119,999	131.1	65.9	22.6
$120,000 or More	154.8	78.7	26.6

Q. DOES THE DEPARTMENT OF ENERGY PROVIDE DATA THAT HELPS TO EXPLAIN WHY LOW-INCOME CUSTOMERS TEND ALSO TO BE LOW USE CUSTOMERS?

A. Yes. The RECS data clearly shows that natural gas consumption increases as the size of the housing unit increases. The related housing characteristics support this conclusion. Residents of single family housing have greater consumption than residents of multi-family housing do. Residents of large multi-family dwellings (5+ units) have lower natural gas consumption than residents of apartments in 2 – 4 unit buildings. Renters have lower consumption than do homeowners. And renters in multi-family dwellings have lower consumption than renters in single-family homes.

Q. DO THE UNDERLYING DEMOGRAPHICS IN PENNSYLVANIA PROVIDE SUPPORT FOR THE APPLICABILITY OF THESE DEPARTMENT OF ENERGY CONCLUSIONS TO CGPA?

A. Yes. Two lines of inquiry support this conclusion. First, Schedule RDC-1 presents the average income in Pennsylvania by the number of rooms in a housing structure, as well as the average income in Pennsylvania by the number of bedrooms in a housing structure. Schedule RDC-1 clearly shows that as housing units get larger in Pennsylvania, average income increases.

There are two standard ways to compare the size of a housing unit when square footage is not available. One way is to look at the number of rooms; the other way is to look at the number of bedrooms. Both of these approaches document that lower-income households live in smaller sized housing units. Schedule RDC-1 shows that:

- While the average income of a Pennsylvania household living in a unit with one room is $26,179, the average income of a household living in an eight-room unit is $91,085. By the time a house gets to have nine rooms, the average income is $111,238.

- The same relationship holds true for housing size measured by the number of bedrooms. While the average income for a Pennsylvania household living in a unit with no bedrooms (known as an "efficiency unit") is $27,065, the average income of a household living in a housing unit with three bedrooms is $66,689; the average income of a household living in a unit with five bedrooms is $91,394.

In both instances (number of rooms and number of bedrooms), the average income increases as the size of the housing unit increases.

In addition to this data, Schedule RDC-2 presents a distribution of Pennsylvania households by income and by the size of the housing unit in which they live, measuring housing unit size by the number of bedrooms in the unit.[2] The data shows that a higher proportion of lower-income households live in smaller housing units and a higher proportion of higher income households live in larger housing units. For example, while roughly 25% to 32% of households with income less than $20,000 live in units with one bedroom or less, less than two percent (2%) of households with incomes greater than $150,000 live in units that small. Conversely, while roughly 55% to 65% of households with incomes of $150,000 or more live in units with four or more bedrooms, only 8% to 12% of households with incomes less than $30,000 do. Consistently, the percentage of households in each of the higher income ranges declines as the number of bedroom declines. In Pennsylvania, higher income households clearly tend to live in larger homes than do lower income households.

Q. IS THERE ANY FINAL ADDITIONAL INFORMATION THAT SUPPORTS YOUR CONCLUSION THAT LOW-INCOME AND LOW-USE ARE CLOSELY RELATED?

A. Yes. Schedule RDC-3 shows that low-income households are disproportionately tenants. The U.S. Census Bureau reports that, in the counties served by CGPA, while 6.3% of homeowners have income less than $15,000, 26.4% of renters do (American Community Survey, Table B25118). While 14.8% of homeowners have income less than $25,000, 44.2% of renters have income that low. On the opposite end of the spectrum, while

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[2] A similar measurement could be made using the total number of rooms rather than the number of bedrooms.

41.9% of homeowners in CGPA counties have income of $75,000 or more, 12.1% of renters do.

This distinction between homeowners and tenants is important because tenant consumption is consistently found to be lower than homeowner consumption. As reported by the U.S. Department of Energy's RECS, while average annual natural gas usage by homeowners in the Northeast is 89 mcf, average annual natural gas usage by renters is 58 mcf. The lower consumption of tenants (versus homeowner) occurs whether comparing the annual consumption of single-family homeowners to that of single-family renters (94 mcf vs. 86 mcf), or comparing the annual consumption of multi-family homeowners to that of multi-family renters (61 mcf vs. 53 mcf). (2009 RECS, Table CE2.2).

Q. DOES THE RECS HELP EXPLAIN THE SIGNIFICANCE OF THIS RELATIONSHIP BETWEEN HOUSEHOLD INCOME AND HOUSING UNIT SIZE FOR PURPOSES OF OBTAINING INSIGHTS INTO THE RELATIONSHIP BETWEEN NATURAL GAS USAGE AND INCOME?

A. Yes. The RECS teaches us that natural gas consumption is associated with the type of structure in which a housing unit is located. When one considers different types of structures, we find, for example, that one-family homes generally have higher gas consumption than do homes in multi-family structures. While single-family detached homes in the Northeast use 97 mcf for space heating, single-family attached homes use 74 mcf; while apartments in 2 – 4 unit buildings use 74 mcf, apartments in 5 or more unit buildings use 41 mcf. (RECS, Table CE2.2). In fact, natural gas usage is largely driven by the floor space of a home. The 2009 RECS documents that natural gas usage increases as the floor space of a unit increases as set forth in Schedule RDC-4.

Q. DO YOU HAVE ANY COMMENT ABOUT THE TOTALITY OF THE INFORMATION YOU PRESENT ABOVE?

A. Yes. The information presented above is important not only for each piece of data standing alone, but is important because of how it fits together into a reasonably explainable pattern. Total per-household residential natural gas consumption is driven largely by the size of the housing unit. Smaller units have lower natural gas consumption. Renters tend to live in smaller housing units, and we can see a correspondingly lower natural gas consumption by renters. Households living in single-family detached homes have larger housing units, and we can see a correspondingly higher natural gas consumption. Households living in multi-family units have smaller units and lower consumption. Lower incomes are associated with renter status, as well as multi-family living. The conclusion that low-income households are also low use households is not only empirically supported, but consistently explained.

Q. HOW IS THIS DATA ON THE RELATIONSHIP BETWEEN INCOME AND USAGE RELEVANT TO THE COMPANY'S PROPOSED CUSTOMER CHARGE?

A. The Company has proposed a significant increase in the fixed monthly customer charge in this base rate case. As is documented above, the substantial increase in the fixed monthly customer charge will disproportionately adversely affect low-use customers.

Data supports the conclusion that those low-use customers will also disproportionately be low-income customers. As a result, the customer population having the greatest payment troubles with which to begin will receive the largest rate increases. This impact not only adversely affects the low-use, low-income customers, but also imposes greater costs that will need to be passed through rates to all ratepayers. Moreover, as I explain further below, an increased customer charge is an added impediment to the use of energy efficiency as a response to these payment difficulties.

C. Increased Customer Charge and Low-Income Ability to Control their Bills.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I discuss the impact that the Company's proposed increased customer charge will have on the ability of low-income customers to control the level of their bills through the implementation of usage reduction measures. Because the Company's increased customer charge creates substantial impediments to the ability of low-income households to control their bill, and thus their bill unaffordability, through usage reduction, the proposed customer charge increase will result in substantial harm to CGPA's inability-to-pay low-income customers.

Given the importance of usage reduction not only in promoting affordability, but in controlling the universal service program costs to non-participating residential ratepayers, increasing the impediments to low-income usage reduction generates adverse impacts to both low-income customers (decreased affordability) and non-low-income customers (increased universal service costs).

Q. WILL THE INCREASED CUSTOMER CHARGE IMPEDE THE PURSUIT OF ENERGY EFFICIENCY INVESTMENTS BY LOW-INCOME CUSTOMERS?

A. Yes. The substantial increase that the Company proposes for its customer charge will substantially impede the ability of low-income households to reduce their bills by reducing their consumption. This occurs because the Company proposes to move a higher proportion of cost recovery to a fixed bill component that cannot be reduced as a result of reduced usage.

Q. ARE THESE RESULTS CONSISTENT WITH RESEARCH YOU HAVE PERFORMED REGARDING MARKET BARRIERS TO LOW-INCOME PURSUIT OF ENERGY EFFICIENCY MEASURES?

A. Yes. I have studied low-income market barriers for energy efficiency in some detail over the past 25-plus years. I have found that low-income households face market barriers that are different from, and more extensive than, those which residential households face in general. These market barriers impede the availability of energy efficiency to low-income customers, even if such efficiency would be an effective, and cost-effective, mechanism to use in controlling home energy costs. Decreasing the extent to which these customers can reduce their bills by reducing consumption further exacerbates their ability to control their consumption, which is limited with which to begin.

Q. DO THESE ADVERSE IMPACTS AFFECT A SIGNIFICANT NUMBER OF LOW-INCOME CUSTOMERS?

A. Yes. The PUC's Bureau of Consumer Services publishes the number of estimated low-income customers for Pennsylvania utilities in its annual Report on Universal Service Programs and Collections Performance. CGPA has more than 25,000 more low-income customers in its service territory in 2013 than it had as recently as 2008. The Company's estimated low-income population has grown by 36,000 customers since 2006.

Moreover, this single aggregate number does not fully reflect the needs of low-income customers in the CGPA service territory. Schedule RDC-5 presents a disaggregation of Poverty for each county in the CGPA service territory for which data is available. As Schedule RDC-5 indicates, the penetration of deep poverty is extensive. For CGPA, the proportion of the low-income population with income below 50% of Poverty (called "deep poverty") exceeds the proportion of the low-income population with income in any other range of income to Poverty level for incomes below 200% of Poverty. The proportion of the low-income population with income below 100% of Poverty exceeds 10% in every CGPA county except Adams (9%), Butler (9%), Chester (7%) and Elk (8%). In contrast, however, counties such as Centre (21%), Clarion (19%), Fayette (18%) and McKean (18%) have a penetration of population with income below 100% of Poverty Level at or exceeding 20%.

In short, the number of customers harmed by CGPA's proposed increased customer charge is substantial.

Q. HAS CGPA UNDERTAKEN ANY RECENT ANALYSIS OF THE IMPACT THAT MOVING INCREASED BILLINGS TO THE FIXED CUSTOMER CHARGE WILL HAVE ON THE COST-EFFECTIVENESS OF ENERGY EFFICIENCY MEASURES?

A. No. CGPA has performed no such analysis within the past ten years. (OCA-II-8). Nor does it have in its possession any such study performed by someone other than itself, whether in Pennsylvania (OCA-II-10) or elsewhere (OCA-II-9).

Q. HAS CGPA UNDERTAKEN ANY RECENT ANALYSIS OF THE IMPACT THAT MOVING INCREASED BILLINGS TO THE FIXED CUSTOMER CHARGE WILL HAVE ON THE COST-EFFECTIVENESS OF ENERGY EFFICIENCY PROGRAMS?

A. No. CGPA has performed no such analysis within the past ten years. (OCA-II-8). Nor does it have in its possession any such study performed by someone other than itself, whether in Pennsylvania (OCA-II-10) or elsewhere (OCA-II-9).

Q. HAS CGPA UNDERTAKEN ANY RECENT ANALYSIS OF THE IMPACT THAT MOVING INCREASED BILLINGS TO THE FIXED CUSTOMER CHARGE WILL HAVE ON TOTAL CONSUMPTION OF NATURAL GAS IN THE CGPA SERVICE TERRITORY?

A. No. CGPA has performed no such analysis within the past ten years. (OCA-II-8). Nor does it have in its possession any such study performed by someone other than itself, whether in Pennsylvania (OCA-II-10) or elsewhere (OCA-II-9).

Q. PLEASE SUMMARIZE WHAT YOU FIND BASED ON THE ABOVE DISCUSSION REGARDING CGPA'S PROPOSED CUSTOMER CHARGE.

A. In the sections above, I document how CGPA is proposing to impose the greatest rate increases on the population of customers who can least afford to pay those rate increases. That result will increase not only the universal service costs to be paid by non-CAP participants, but will also increase other ordinary expenses to be paid by all customers, including working capital, uncollectibles and credit and collection expenses. There will not only be a short-term increase in distribution prices, but also a longer-term increase in natural gas supply prices because of the resulting reduction in customer-funded usage reduction.

I further explained how the substantial increase that the Company proposes for its customer charge will impede the ability of low-income households to reduce their bills by reducing their consumption. This occurs because the Company proposes to move a much higher proportion of its cost recovery to a fixed bill component that cannot be reduced as a result of reduced usage.

I conclude that the Company is imposing higher costs on consumers, both low-income and non-low-income, while at the same time erecting further barriers for customers who wish to respond to their inability to pay higher bills by reducing their consumption. This inability to reduce consumption through energy efficiency investments harms both CAP participants and the CAP non-participants who pay the universal service surcharges.

Ultimately, my findings and recommendations related to CGPA's customer charge support the reasonableness of customer charge recommendations presented in the testimony of OCA witness Mierzwa.

Part 2. Universal Service Cost Recovery.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the universal service costs that CGPA seeks to recover through its Universal Service Rider. I conclude that while some of the costs that the Company seeks to recover through the Rider are appropriate, other costs are inappropriate for the Rider and should not be approved.

Q. DO YOU ADDRESS ANY UNIVERSAL SERVICE PROGRAM STRUCTURE AND/OR OPERATIONAL ISSUES IN THIS SECTION?

A. Not at this time. My testimony below is limited solely to the rate issues involving universal service cost recovery. My failure to address any structural and/or operational issues for CGPA's universal service programs should not be construed as an agreement with all aspects of the programs.

A. Universal Service Administrative Costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider the reasonableness of the universal services administrative costs that the Company proposes to collect through its Universal Service Rider. I conclude that internal administrative costs should be collected in base rates rather than through the Universal Service Rider.

Q. WHAT UNIVERSAL SERVICE ADMINISTRATIVE COSTS DOES CGPA PROPOSE TO RECOVER THROUGH THE UNIVERSAL SERVICE RIDER IN THIS PROCEEDING?

A. The category of administrative costs that CGPA seeks to recover through its Universal Service Rider on which I will focus includes administrative costs associated with internal staffing. Internal staffing is an inappropriate cost to recover through the Universal Service Rider. According to the Company, CGPA seeks to recover for LIURP "all internal Columbia program staff labor, benefit costs allocable to those labor charges, expenses associated with those staff members, NISOURCE Customer Contact Center labor charged to the program. . ." In addition, CGPA states that it seeks to recover "all internal Columbia program staff labor [and] benefit costs allocable to those labor charges" attributable to "audits and rebates." (OCA-II-1).

The Company seeks to collect a *portion* of the staff cost of four different staff members (Director, Rates & Regulatory; Manager, Universal Service; Manager, Customer

Programs; Administrative Assistant) through the Universal Service Rider. All time for the Quality Assurance Coordinator and for the Universal Service Clerk is collected through the Universal Service Rider. The 2014 recovery of these staff costs included:

Staff position	Labor	Benefits	% Charged to LIURP	% Charged to Audits & Rebates
Director, Rates and Regulatory	$6,611	$1,899.34	2.50%	2.50%
Manager, Universal Service	$23,980	$6,889.45	27%	0%
Manager, Customer Programs	$51,719	$14,858.87	45%	3%
Quality Assurance Coordinator	$57,183	$16,428.68	50%	50%
Administrative Assistant	$17,301	$4,970.58	19.6%	15%
Universal Service Clerk	$38,966	$11,194.93	50%	50%
Total	$195,760	$56,242		

(OCA-II-2; OCA-II-3). The Company anticipates these costs to increase by 3% annually, reflecting "annual merit increases." (OCA-II-2). In addition, CGPA proposes to collect its internal "phone center" expenses associated with LIURP through the Universal Service Rider. (OCA-II-5). The Company reported phone center expenses of $130,940.51 in its Annual Reconciliation of Rider USP for expenses incurred during the 12 months ending December 31, 2014. (OCA-I-1).

Q. SHOULD THESE INTERNAL UNIVERSAL SERVICE ADMINISTRATIVE COSTS BE COLLECTED THROUGH THE UNIVERSAL SERVICE RATE RIDER?

A. No. These costs should be included in base rates. The administrative costs to be collected through the Universal Service Rider should be only those incremental administrative costs that are directly attributable to the implementation of universal service programs. A cost is directly attributable to the universal service program when it would not have been incurred but-for the existence of the program. The internal administrative costs that I have identified above do not meet this test for recovery through the Universal Service Rider.

Q. WHAT PROBLEM PRESENTS ITSELF IN THE CGPA UNIVERSAL SERVICE RIDER REGARDING THE RECOVERY OF ADMINISTRATIVE COSTS?

A. The CGPA Universal Service Rider allows the recovery of administrative costs that are not already included in base rates. In deciding upon whether riders were appropriate for CAP costs in 2006,[3] the Commission directed that decisions be made on a case-by-case basis. ". . .[U]tilities are free to propose quarterly or annual reconciliation, and other parties are free to contest the proposal. The Commission will then make a decision based upon the record of each case."[4] The Commission did note in that CAP cost recovery Order, however, that "surcharges have been used principally by natural gas and electric companies to recover certain expenses *not covered in their base rates*."[5]

Q. HASN'T CGPA REMOVED ALL INTERNAL ADMINISTRATIVE COSTS THAT IT PROPOSES TO COLLECT THROUGH ITS UNIVERSAL SERVICE RIDER FROM BASE RATES?

A. There is no assurance that this will be the case on an ongoing basis, particularly if CGPA is allowed to collect an allocated portion of an internal staff member's salary and benefits

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[3] Pennsylvania PUC, Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms, Docket M-00051923, Final Investigatory Order (issued October 19, 2006).

[4] Final Investigatory Order, at 23.

[5] Final Investigatory Order, at 23 (emphasis added).

through the Universal Service Rider. Without incorporating the limitations that the Commission has previously articulated directly into all cost recovery through the Universal Service Rider, additional dollars could be allocated to the Rider simply by redefining what constitutes a "support" function. Moreover, while the Company has identified the particular staff which it says are devoted to "support" the Universal Service program in question, there is no limitation in the Universal Service Rider that *only* the costs of those in-house staff are subject to recovery through the Rider. The costs of other staff would already have been included in base rates. Allowing recovery of additional staff, or of a higher "portion" of staff time, through the Universal Service Rider would thus involve an over-collection. As the Commission explicitly stated in its CAP cost recovery order, "The law requires 'full recovery' of CAP costs, but not 'double recovery.'"[6]

Q. IS THERE PRECEDENT FOR CGPA COLLECTING ITS INTERNAL UNIVERSAL SERVICE ADMINISTRATIVE COSTS THROUGH BASE RATES?

A. Yes. The Company reports that its $800,036 CAP expenses associated with "internal administrative labor and expenses, contact center labor, materials [and] supplies" is collected through base rates. (OCA-II-7). In addition, its entire hardship fund administrative costs ($34,000) as well as both its "energy assistance outreach and processing" ($180,000) and its "CARES community outreach" ($260,000) is collected through base rates as well. (OCA-II-7).

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[6] Final Investigatory Order, at 38.

Q. DO YOU PROPOSE THAT ALL UNIVERSAL SERVICE ADMINISTRATIVE COSTS BE COLLECTED THROUGH BASE RATES IN THIS PROCEEDING?

A. No. What I propose is to treat the administrative costs I identify above in the same way CGPA treats its internal staff CAP administrative costs. These internal staff costs should be collected in base rates.

B. Emergency Repair Program.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine and comment upon the CGPA proposal to increase funding for its Emergency Repair Program (ERP) from $500,000 to $600,000. CGPA further proposes to collect its ERP costs through the Company's Universal Service Rider. It finally proposes to expand income eligibility benefits for the ERP from 150% to 200% of Poverty, provided that benefits to the expanded population do not exceed 10% of total ERP funding.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE COMPANY'S ERP INITIATIVE.

A. According to Company witness Krajovic, the ERP is directed toward "heating related emergencies" such as "the repair or replacement of house and service lines, heating systems and water tanks." (CGPA Statement 12, page 10). The over-arching objective of the program is to make "repairs. . .critical to maintaining heat." (Id.).

Q. DO YOU PROPOSE ANY CHANGES TO THE STRUCTURE AND/OR OPERATION OF THE COMPANY'S ERP?

A. No. I address only the need for the ERP funding and the appropriate cost-recovery.

Q. DOES THE ERP SERVE AN IDENTIFIED NEED IN THE CGPA SERVICE TERRITORY?

A. Yes. To the extent that low-income households have inoperable natural gas heating systems which they cannot afford to repair or replace, those households tend to turn to non-natural gas secondary space heating equipment such as portable electric space heaters as their primary heating source. These portable heaters are not intended to be a primary source of space heating. The use of portable electric heaters as a primary heating source is extraordinarily expensive from the perspective of the electricity supplier. To the extent that the customer is a participant in the electric CAP for the electric distribution company serving the CGPA customer, universal service costs to that electric company will be higher than they should be. Nonetheless, the electric utility may not use electric universal service funds, supplied by electric ratepayers, to repair or replace inoperable natural gas systems.

To the extent that the customer is *not* a participant in the corresponding electric CAP, the electric distribution company will experience the same increased payment difficulties, along with the corresponding costs, that are otherwise associated with high bills and low-incomes. The presence of electric supplemental heating utensils being used as a primary heating source has been increasingly recognized as a problem associated with broken and inoperable natural gas equipment.

In addition, the use of electric portable heaters as the primary heating source when natural gas equipment is inoperable, and households cannot afford to repair or replace it, poses extraordinary dangers as well. For example, in a report I prepared for the National Fuel Funds Network (NFFN), the national association of hardship funds, I found:

> While home heating equipment is no longer the single most substantial cause of home fires, it remains one of the leading factors contributing to fires, as well as to fire-related injuries and deaths. In particular, according to the National Fire Protection Association (NFPA), portable and fixed space heaters present a risk of harm. While portable space heaters are not the major cause of home heating fires, they play a much more substantial role in deaths and injuries. Portable and fixed space heaters (and their related equipment such as fireplaces, chimneys and chimney collectors) accounted for roughly two of every three (65%) home heating fires in 1998 and three of every four (76%) associated deaths. Each of these devices has a higher death rate per million households using them than do the various types of central heating units or water heaters.[7]

I further reported that such circumstances are a particular danger in low-income households, citing the National Fire Protection Association (NFPA) for the propositions that:

> Aside from low-income status being associated with an increased incidence of home fires generally, it is associated with deadly fires as well. Several factors contribute to this result, the NFPA has found:
>
> - Not being able to afford smoke detectors. 'Three fifths of all home fire deaths occur in the approximately seven percent of homes without detectors.' One-third of all homes with detectors that have fires have detectors that are not working. Not always being able to afford child

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[7] Colton (December 2001). *In Harm's Way: Home Heating, Fire Hazards and Low-Income Households*, National Fuel Funds Network: Washington D.C. (citations omitted).

care and leaving children unattended or unsupervised. Unattended children are those left completely alone with no adult or babysitter to look after them.

- Not being able to afford a telephone. 'Without a telephone, the chance of a delay in alarm when reporting a fire to the fire department increases.' According to the Federal Communications Commission (FCC), . . .telephone penetration rates for households relying exclusively on public assistance for income fall to only 45%.

- Living in less fire resistant housing, as well as using less fire resistant furniture and mattresses. 'Diminished financial resources prevent many families from investing in fire safety because the resources they do have usually go to other, more immediate necessities.'

Finally, there is little question but that these fires, and the fire deaths that accompany them, are associated with inoperable heating systems. I quoted the NFPA as reporting: "Both home structure fires and home structure fire deaths show a sharp peak in the cold-weather months. . .Half of the home heating fires and three-fourths of the home-heating fire deaths occurred in the months of December, January and February."

Q. DOES THE NEED FOR A PROGRAM SUCH AS ERP EXTEND TO HOUSEHOLDS WITH INCOME BETWEEN 150% AND 200% OF THE FEDERAL POVERTY LEVEL?

A. Yes. I have examined the self-sufficiency incomes for the counties that CGPA serves. Every two years, the University of Washington's School of Social Work prepares a study of "self-sufficiency" incomes in Pennsylvania for PathWays PA. The self-sufficiency standard measures how much income a family of a certain composition in a given place needs in order to adequately meet their basic needs without public or private assistance. Schedule RDC-6 presents, by county, the proportions of the population in CGPA's service territory that are below the self-sufficiency standard, disaggregated further by whether the household income is above or below Poverty Level.

In every county, a substantial proportion of the total household population lives with income that is below the self-sufficiency standard. In every county, between 40% and 80% of the population with income below self-sufficiency nonetheless had income above the Poverty Level. Indeed, in 17 of the 25 CGPA counties, more than half of the population with an annual income below the self-sufficiency standard nonetheless had an income above the Poverty Level.

While Pathways PA does not report the number of households with incomes at or below the self-sufficiency standard, disaggregated by various ranges of Poverty Level, Pathways does report that the self-sufficiency income was roughly 250% of Poverty. Accordingly, it is reasonable to conclude that a program component extending funding, not to exceed 10% of the total budget as proposed by CGPA, to households with income between 150% and 200% of Poverty falls well within the need for such universal service funding.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that the ERP as operated and proposed to be funded by CGPA is an appropriate "universal service program," the costs of which are appropriately collected through the CGPA Universal Service Rider.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
	:	Docket No. R-2015-2468056
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 4, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ____________________
Roger D. Colton

Consultant Address: 34 Warwick Road
Belmont, MA 02478

DATED: June 17, 2015

Colton Schedules

Schedule RDC-1

Average Income by Number of Rooms or Number of Bedrooms in Housing Unit (Pennsylvania) American Community Survey (2013: 3-year data)		
Number of Rooms / Bedrooms	Average Income by Number of Rooms / Number of Bedrooms	
	Rooms	Bedrooms
0	Xxx	$27,065
1	$26,179	$34,694
2	$35,432	$49,655
3	$36,497	$66,689
4	$43,757	$97,003
5 /a/	$52,291	$91,394
6	$60,481	
7	$74,182	
8	$91,085	
9 /b/	$111,238	
Total	$63,777	$63,777

NOTES:

/a/ For bedrooms, data is top-coded at 5 bedrooms.
/b/ For rooms, data is top coded at 10 rooms.

Schedule RDC-2

Distribution of Housing Units by Income and Housing Unit Size (Number of Bedrooms): Pennsylvania

	$1 - $10,000	$10 - $20,000	$20 - $30,000	$30 - $40,000	$40 - $50,000	$50 - $75,000	$75 - $150,000	$150 - $250,000	$250,000 or more
No bedroom	6.2%	3.6%	2.5%	1.6%	1.3%	0.5%	0.2%	0.3%	0.0%
1 bedroom	26.0%	21.7%	14.7%	11.4%	9.4%	5.9%	2.9%	1.7%	1.7%
2 bedrooms	29.5%	29.2%	29.7%	27.5%	27.4%	22.7%	13.7%	8.2%	7.9%
3 bedrooms	30.2%	35.9%	41.1%	45.8%	46.3%	51.8%	51.3%	36.6%	24.4%
4 bedrooms	6.4%	8.0%	10.1%	11.5%	13.1%	16.4%	27.4%	43.9%	48.2%
5 or more bedrooms	1.6%	1.6%	2.0%	2.2%	2.6%	2.7%	4.5%	9.4%	17.8%
Total bedrooms	100%	100%	100%	100%	100%	100%	100%	100%	100%

American Community Survey (2013: 3-year data)

Schedule RDC-3

Tenure and Income (CGPA Counties)		
Household Income	Percent Home Owner	Percent Tenant
Less than $5,000	1.4%	6.4%
$5,000 - $9,999	1.6%	9.3%
$10,000 - $14,999	3.3%	10.7%
$15,000 - $19,999	4.0%	9.7%
$20,000 - $24,999	4.5%	8.1%
$25,000 - $34,999	9.3%	14.0%
$35,000 - $49,999	13.3%	14.6%
$50,000 - $74,999	20.5%	15.2%
$75,000 - $99,999	14.7%	6.3%
$100,000 - $149,999	16.0%	3.8%
$150,000 or more	11.2%	2.0%
Total	100%	100%
SOURCE: American Community Survey (2013: 3-year data) (Table B25118).		

Schedule RDC-4

Gas Usage by Income (Northeast)

Total Square Footage	Million Btu	MCF
Fewer than 500	41.1	40
500 to 999	48.9	48
1,000 to 1,499	68.9	67
1,500 to 1,999	85.0	83
2,000 to 2,499	87.5	85
2,500 to 2,999	94.3	92
3,000 to 3,499	105.3	103
3,500 to 3,999	97.9	96
4,000 or More	125.5	122

Schedule RDC-5

B17002: RATIO OF INCOME TO POVERTY LEVEL IN THE PAST 12 MONTHS - Universe: Population for whom poverty status is determined

County	Total	Under .50	.50 to .74	.75 to .99	1.00 to 1.24	1.25 to 1.49	1.50 to 1.74	1.75 to 1.84	1.85 to 1.99	2.00 to 2.99	3.00 to 3.99	4.00 to 4.99	5.00 and over
Adams	97,111	3,533	2,191	2,977	4,208	4,404	4,031	1,849	2,454	19,057	17,589	11,354	23,464
Allegheny	1,196,987	75,862	42,625	41,578	45,092	47,785	48,277	19,726	25,613	191,446	171,169	147,146	340,668
Armstrong	67,620	3,338	2,711	3,057	3,307	3,462	3,670	1,941	2,170	14,775	10,316	6,574	12,299
Beaver	167,775	8,525	4,998	5,928	6,712	7,284	7,835	3,822	5,168	30,670	25,232	20,727	40,874
Bedford	48,346	2,177	1,890	2,491	2,866	2,451	2,251	810	2,252	9,790	9,037	4,967	7,364
Butler	179,860	7,245	4,694	4,603	6,259	5,512	6,800	2,780	4,167	29,786	28,301	23,078	56,635
Centre	138,699	18,178	5,640	5,179	4,800	4,675	5,506	2,405	2,349	22,974	19,147	11,995	35,851
Chester	493,200	17,035	7,949	10,739	9,907	12,458	13,701	5,325	8,878	59,549	62,410	55,997	229,252
Clarion	37,757	3,347	1,725	1,938	1,598	1,831	2,022	955	1,005	8,317	5,696	3,394	5,929
Clearfield	75,861	3,910	3,060	3,903	4,646	4,006	4,854	1,619	2,916	14,591	11,966	8,726	11,664
Elk	31,245	1,316	409	827	1,468	1,568	1,618	1,029	1,029	7,327	5,476	3,970	5,208
Fayette	131,522	10,677	6,225	7,408	7,069	7,738	6,099	2,024	4,777	27,500	19,659	13,962	18,384
Franklin	149,059	6,193	5,783	6,660	5,725	7,534	7,340	2,660	4,113	28,514	24,053	19,395	31,089
Greene	33,156	1,936	1,029	1,704	1,472	2,078	1,246	883	1,173	6,693	4,419	3,751	6,772
Indiana	82,266	7,524	2,968	3,539	4,381	4,350	4,083	1,787	2,849	15,713	12,386	7,708	14,978
Jefferson	43,933	2,346	2,182	2,052	2,462	2,481	2,866	1,219	1,635	9,764	6,524	4,546	5,856
Lawrence	87,397	6,140	3,181	3,386	3,807	4,406	4,720	1,889	2,664	17,919	12,949	9,437	16,899
McKean	39,869	2,951	2,140	2,157	2,008	2,222	1,978	970	1,012	8,730	6,403	3,670	5,628
Mercer	108,300	5,176	4,284	4,662	5,619	5,950	6,096	2,522	3,326	22,777	17,980	10,720	19,188
Somerset	72,251	2,997	2,456	3,339	3,314	3,375	4,581	1,288	2,858	15,293	11,126	9,253	12,371
Venango	53,077	2,891	2,890	2,911	2,678	2,658	3,235	1,137	1,757	12,230	7,961	4,976	7,753
Warren	40,206	2,269	1,397	1,809	1,937	2,455	2,134	1,058	1,429	8,465	6,002	4,318	6,933
Washington	203,210	10,724	4,953	6,215	7,261	6,822	7,690	3,628	5,240	34,235	33,199	28,374	54,869
Westmoreland	354,972	15,221	10,020	12,183	14,689	16,049	16,824	6,561	9,013	65,316	55,475	41,044	92,577
York	428,488	19,120	12,137	14,862	15,984	17,539	19,592	7,520	8,712	79,802	67,744	54,868	110,608
Total		240,631	139,537	156,107	169,269	181,093	189,049	77,407	108,559	761,233	652,219	513,950	1,173,113

Schedule RDC-6

The Self-Sufficiency Standard and Federal Poverty Level (CGPA Counties)						
			Below Self-Sufficiency Standard			
	Below Standard and Below Poverty		Below Standard and Above Poverty		Total Below Standard	
County	Number	Percent of Total	Number	Percent of Total	Number	Percent of Total
Adams	1,300	5.3%	2,901	11.9%	4,201	17.2%
Allegheny	32,576	9.5%	44,968	13.2%	77,544	22.7%
Armstrong	3,268	18.0%	2,293	12.7%	5,562	30.7%
Beaver	6,802	15.5%	3,967	9.0%	10,769	24.5%
Bedford	1,278	11.5%	1,427	12.8%	2,705	24.3%
Butler	3,493	7.0%	6,352	12.8%	9,845	19.8%
Centre	7,002	16.8%	7,238	17.3%	14,240	34.1%
Chester	6,199	4.5%	20,867	15.1%	27,066	19.6%
Clarion	1,752	17.4%	1,246	12.4%	2,998	29.8%
Clearfield	3,051	15.5%	2,381	12.1%	5,431	27.7%
Elk	753	9.3%	1,687	20.9%	2,439	30.3%
Fayette	4,540	14.7%	6,165	20.0%	10,705	34.7%
Franklin	3,618	10.0%	2,996	8.3%	6,614	18.3%
Greene	1,131	13.5%	1,178	14.0%	2,310	27.5%
Indiana	4,046	18.0%	2,839	12.7%	6,884	30.7%
Jefferson	1,680	15.5%	1,311	12.1%	2,992	27.7%
Lawrence	2,650	12.3%	3,193	14.9%	5,843	27.2%
McKean	985	9.3%	2,207	20.9%	3,191	30.3%
Mercer	3,036	11.0%	5,068	18.3%	8,104	29.3%
Somerset	1,627	9.0%	2,128	11.7%	3,755	20.7%
Venango	2,415	17.4%	1,717	12.4%	4,132	29.8%
Warren	1,338	13.2%	1,498	14.8%	2,835	28.0%
Washington	4,925	9.6%	6,783	13.2%	11,707	22.7%
Westmoreland	8,328	9.0%	10,624	11.4%	18,952	20.4%
York	7,800	6.6%	12,389	10.5%	20,189	17.1%
Total	115,593	xxx	155,423	xxx	271,013	Xxx

Appendix A

ROGER D. COLTON

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PROFESSIONAL AFFILIATIONS:

Coordinator: BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator: Belmont Affordable Shelter Fund (BASF)
Chair: Belmont Solar Initiative Oversight Committee
Co-Chair: Belmont Energy Committee
Member: Massachusetts Municipal Energy Group (Mass Municipal Association)
Past Chair: Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Member: Board of Directors, Belmont Housing Trust, Inc.
Past Chair: Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member: Belmont (MA) Energy and Facilities Work Group
Past Member: Belmont (MA) Uplands Advisory Committee
Past Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Chair: Fair Housing Committee, Town of Belmont (MA)
Past Member: Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: Board of Directors, Affordable Comfort, Inc. (ACI)
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.

Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

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COLTON EXPERIENCE AS EXPERT WITNESS

2000 – PRESENT

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PPL Utilities	Office of Consumer Advocate	R-2015-2469275	Rate design / customer service	Pennsylvania	15
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2015-2468056	Rate design / customer service	Pennsylvania	15
I/M/O PECO Energy Company	Office of Consumer Advocate	R-2015-2468981	Rate design / customer service	Pennsylvania	15
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	P-2014-2459362	Demand Side Management	Pennsylvania	15
I/M/O SBG Management v. Philadelphia Gas Works	SBG Management	C-2012-2308454	Customer service	Pennsylvania	15
I/M/O Manitoba Hydro	Resource Action Centre		Low-income affordability	Manitoba	15
I/M/O FirstEnergy Companies (Met Ed, WPP, Penelec, Penn Power)	Office of Consumer Advocate	R-2014-2428742 (8743, 8744, 8745)	Rate design / customer service / storm communications	Pennsylvania	14
I/M/O Xcel Energy Company	Energy CENTS Coalition	E002/GR-13-868	Rate design / energy conservation	Minnesota	14
I/M/O Peoples Gas Light and Coke Company / North Shore Gas	Office of Attorney General	14-0224 / 14--0225	Rate design / customer service	Illinois	14
I/M/O Columbia Gas of Pennsylvania	Office of Consumer Advocate	R-2014-2406274	Rate design / customer service	Pennsylvania	14
I/M/O Duquesne Light Company Rates	Office of Consumer Advocate	R-2013-2372129	Rate design / customer service / storm communications	Pennsylvania	13
I/M/O Duquesne Light Company Universal Service	Office of Consumer Advocate	M-2013-2350946	Low-income program design	Pennsylvania	13
I/M/O Peoples-TWP	Office of Consumer Advocate	*P-2013-2355886*	*Low-income program design / rate design*	*Pennsylvania*	*13*
I/M/O PECO CAP Shopping Plan	Office of Consumer Advocate	P-2013-2283641	Retail shopping	Pennsylvania	13

CASE NAME	CLIENT NAME	Docket No. (If available)	TOPIC	JURIS.	YEAR
I/M/O PECO Universal Service Programs	Office of Consumer Advocate	M-201202290911	Low-income program design	Pennsylvania	13
I/M/O Privacy of Consumer Information	Legal Services Advocacy Project	CI-12-1344	Privacy of SSNs & consumer information	Minnesota	13
I/M/O Atlantic City Electric Company	Division of Rate Counsel	BPU-12121071	Customer service / Storm communications	New Jersey	13
I/M/O Jersey Central Power and Light Company	*Division of Rate counsel*	*BPU-12111052*	*Customer service / Storm communications*	*New Jersey*	*13*
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2012-2321748	Universal service	Pennsylvania	13
I/M/O Public Service Company of Colorado Low-Income Program Design	Xcel Energy d/b/a PSCo	12A--EG	Low-income program design / cost recovery	Colorado	12
I/M/O Philadelphia Water Department.	Philadelphia Public Advocate	No. Docket No.	Customer service	Philadelphia	12
I/M/O PPL Electric Power Corporation	Office of Consumer Advocate	R-2012-2290597	Rate design / low-income programs	Pennsylvania	12
I/M/O Peoples Natural Gas Company	Office of Consumer Advocate	R-2012-2285985	Rate design / low-income programs	Pennsylvania	12
I/M/O Merger of Constellation/Exelon	Office of Peoples Counsel	CASE 9271	Customer Service	Maryland	11
I/M/O Duke Energy Carolinas	North Carolina Justice Center	E-7, SUB-989	Customer service/low-income rates	North Carolina	11
Re. Duke Energy/Progress Energy merger	NC Equal Justice foundation	E-2, SUB 998	Low-income merger impacts	North Carolina	11
Re. Atlantic City Electric Company	Division of Rate Counsel	ER1186469	Customer Service	New Jersey	11
Re. Camelot Utilities	Office of Attorney General	11-0549	Rate shock	Illinois	11
Re. UGI—Central Penn Gas	Office of Consumer Advocate	R-2010-2214415	Low-income program design/cost recovery	Pennsylvania	11
Re. National Fuel Gas	Office of Consumer Advocate	M-2010-2192210	Low-income program cost recovery	Pennsylvania	11
Re. Philadelphia Gas Works	Office of Consumer Advocate	P-2010-2178610	Program design	Pennsylvania	11
Re. PPL	Office of Consumer Advocate	M-2010-2179796	Low-income program cost recovery	Pennsylvania	11
Re. Columbia Gas Company	*Office of Consumer Advocate*	R-2010-2215623	*Rate design/Low-income program cost recovery*	*Pennsylvania*	11
Crowder et al. v. Village of Kauffman	Crowder (plaintiffs)	3:09-CV-02181-M	Section 8 utility allowances	Texas Fed Court	11
I/M/O Peoples Natural Gas Company.	Office of Consumer Advocate	T-2010-220172	Low-income program design/cost recovery	Pennsylvania	11
I/M/O Commonwealth Edison	Office of Attorney General	10-0467	Rate design/revenue requirement	Illinois	10

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O National Grid d/b/a Energy North	NH Legal Assistance	DG-10-017	Rate design/revenue requirement	New Hampshire	10
I/M/O Duquesne Light Company	Office of Consumer Advocate	R-2010-2179522	Low-income program cost recovery	Pennsylvania	10
I/M/O Avista Natural Gas Corporation	The Opportunity Council	UE-100467	Low-income assistance/rate design	Washington	10
I/M/O Manitoba Hydro	Resource Conservation Manitoba (RCM)	CASE NO. 17/10	Low-income program design	Manitoba	10
I/M/O TW Phillips	Office of Consumer Advocate	R-2010-2167797	Low-income program cost recovery	Pennsylvania	10
I/M/O PECO Energy—Gas Division	Office of Consumer Advocate	R-2010-2161592	Low-income program cost recovery	Pennsylvania	10
I/M/O PECO Energy—Electric Division	Office of Consumer Advocate	R-2010-2161575	Low-income program cost recovery	Pennsylvania	10
I/M/O PPL Energy	Office of Consumer Advocate	R-2010-2161694	Low-income program cost recovery	Pennsylvania	10
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2009-2149262	Low-income program design/cost recovery	Pennsylvania	10
I/M/O Atlantic City Electric Company	Office of Rate Council	R09080664	Customer service	New Jersey	10
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	R-2009-2139884	Low-income program cost recovery	Pennsylvania	10
I/M/O Philadelphia Gas Works	Office of Consumer Advocates	R-2009-2097639	Low-income program design	Pennsylvania	10
I/M/O Xcel Energy Company	Xcel Energy Company (PSCo)	085-146G	Low-income program design	Colorado	09
I/M/O Atmos Energy Company	Atmos Energy Company	09AL-507G	Low-income program funding	Colorado	09
I/M/O New Hampshire CORE Energy Efficiency Programs	New Hampshire Legal Assistance	D-09-170	Low-income efficiency funding	New Hampshire	09
I/M/O Public Service Company of New Mexico (electric)	Community Action of New Mexico	08-00273-UT	Rate Design	New Mexico	09
I/M/O UGI Pennsylvania Natural Gas Company (PNG)	Office of Consumer Advocate	R-2008-2079675	Low-income program	Pennsylvania	09
I/M/O UGI Central Penn Gas Company (CPG)	Office of Consumer Advocate	R-2008-2079660	Low-income program	Pennsylvania	09
I/M/O PECO Electric (provider of last resort)	Office of Consumer Advocate	R-2008-2028394	Low-income program	Pennsylvania	08
I/M/O Equitable Gas Company	Office of Consumer Advocate	R-2008-2029325	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Office of Ohio Consumers' Counsel	08-072-GA-AIR	Rate design	Ohio	08
I/M/O Dominion East Ohio Gas Company	Office of Ohio Consumers' Counsel	07-829-GA-AIR	Rate design	Ohio	08

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O Vectren Energy Delivery Company	Office of Ohio Consumers' Counsel	07-1080-GA-AIR	Rate design	Ohio	08
I/M/O Public Service Company of North Carolina	NC Department of Justice	G-5, SUB 495	Rate design	North Carolina	08
I/M/O Piedmont Natural Gas Company	NC Department of Justice	G-9, SUB 550	Rate design	North Carolina	08
I/M/O National Grid	New Hampshire Legal Assistance	DG-08-009	Low-income rate assistance	New Hampshire	08
I/M/O EmPower Maryland	Office of Peoples Counsel	PC-12	Low-income energy efficiency	Maryland	08
I/M/O Duke Energy Carolinas Save-a-Watt Program	NC Equal Justice Foundation	E-7, SUB 831	Low-income energy efficiency	North Carolina	08
I/M/O Zia Natural Gas Company	Community Action New Mexico	08-00036-UT	Low-income/low-use rate design	New Mexico	08
I/M/O Universal Service Fund Support for the Affordability of Local Rural Telecomm Service	Office of Consumer Advocate	I-0004010	Telecomm service affordability	Pennsylvania	08
I/M/O Philadelphia Water Department	Public Advocate	No Docket No.	Credit and Collections	Philadelphia	08
I/M/O Portland General Electric Company	Community Action–Oregon	UE-197	General rate case	Oregon	08
I/M/O Philadelphia Electric Company (electric)	Office of Consumer Advocate	M-00061945	Low-income program	Pennsylvania	08
I/M/O Philadelphia Electric Company (gas)	Office of Consumer Advocate	R-2008-2028394	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2008-2011621	Low-income program	Pennsylvania	08
I/M/O Public Service Company of New Mexico	Community Action New Mexico	08-00092-UT	Fuel adjustment clause	New Mexico	08
I/M/O Petition of Direct Energy for Low-Income Aggregation	*Office of Peoples Counsel*	CASE 9117	*Low-income electricity aggregation*	*Maryland*	*07*
I/M/O Office of Consumer Advocate et al. v. Verizon and Verizon North	Office of Consumer Advocate	C-20077197	Lifeline telecommunications rates	Pennsylvania	07
I/M/O Pennsylvania Power Company	Office of Consumer Advocate	P-00072437	Low-income program	Pennsylvania	07
I/M/O National Fuel Gas Distribution Corporation	Office of Consumer Advocate	M-00072019	Low-income program	Pennsylvania	07
I/M/O Public Service of New Mexico--Electric	Community Action New Mexico	07-00077-UT	Low-income programs	New Mexico	07
I/M/O Citizens Gas/NIPSCO/Vectren for Universal Service Program	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	CASE 43077	Low-income program design	Indiana	07

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PPL Electric	Office of Consumer Advocate	R-00072155	Low-income program	Pennsylvania	07
I/M/O Section 15 Challenge to NSPI Rates	Energy Affordability Coalition	P-886	Discrimination in utility regulation	Nova Scotia	07
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	R-00049157	Low-income and residential collections	Pennsylvania	07
I/M/O Equitable Gas Company	Office of Consumer Advocate	M-00061959	Low-income program	Pennsylvania	07
I/M/O Public Service Company of New Mexico	Community Action of New Mexico	Case No. 06-000210-UT	Late charges / winter moratorium / decoupling	New Mexico	06
I/M?O Verizon Massachusetts	ABCD	Case NO. DTE 06-26	Late charges	Massachusetts	06
I/M/O Section 11 Proceeding, Energy Restructuring	Office of Peoples Counsel	PC9074	Low-income needs and responses	Maryland	06
I/M/O Citizens Gas/NIPSCO/Vectren for Univ. Svc. Program	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	Case No. 43077	Low-income program design	Indiana	06
I/M/O Public Service Co. of North Carolina	North Carolina Attorney General/Dept. of Justice	G-5, Sub 481	Low-income energy usage	North Carolina	06
I/M/O Electric Assistance Program	New Hampshire Legal Assistance	DE 06-079	Electric low-income program design	New Hampshire	06
I/M/O Verizon Petition for Alternative Regulation	New Hampshire Legal Assistance	DM-06-072	Basic local telephone service	New Hampshire	06
I/M/O Pennsylvania Electric Co/Metropolitan Edison Co.	Office of Consumer Advocate	N/A	Universal service cost recovery	Pennsylvania	06
I/M/O Duquesne Light Company	Office of Consumer Advocates	R-00061346	Universal service cost recovery	Pennsylvania	06
I/M/O Natural Gas DSM Planning	Low-Income Energy Network	EB-2006-0021	Low-income gas DSM program.	Ontario	06
I/M/O Union Gas Co.	Action Centre for Tenants Ontario (ACTO)	EB-2005-0520	Low-income program design	Ontario	06
I/M/O Public Service of New Mexico merchant plant	Community Action New Mexico	05-00275-UT	Low-income energy usage	New Mexico	06
I/M/O Customer Assistance Program design and cost recovery	Office of Consumer Advocate	M-00051923	Low-income program design	Pennsylvania	06
I/M/O NIPSCO Proposal to Extend Winter Warmth Program	Northern Indiana Public Service Company	Case 42927	Low-income energy program evaluation	Indiana	05
I/M/O Piedmont Natural Gas	North Carolina Attorney General/Dept. of Justice	G-9, Sub 499	Low-income energy usage	North Carolina	05

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PSEG merger with Exelon Corp.	Division of Ratepayer Advocate	EM05020106	Low-income issues	New Jersey	05
Re. Philadelphia Water Department	Public Advocate	No docket number	Water collection factors	Philadelphia	05
I/M/O statewide natural gas universal service program	New Hampshire Legal Assistance	N/A	Universal service	New Hampshire	05
I/M/O Sub-metering requirements for residential rental properties	Tenants Advocacy Centre of Ontario	EB-2005-0252	Sub-metering consumer protections	Ontario	05
I/M/O National Fuel Gas Distribution Corp.	Office of Consumer Advocate	R-00049656	Universal service	Pennsylvania	05
I/M/O Nova Scotia Power, Inc.	Dalhousie Legal Aid Service	NSUARB-P-881	Universal service	Nova Scotia	04
I/M/O Lifeline Telephone Service	National Ass'n State Consumer Advocates (NASUCA)	*WC 03-109*	*Lifeline rate eligibility*	*FCC*	*04*
Mackay v. Verizon North	Office of Consumer Advocate	C20042544	Lifeline rates—vertical services	Pennsylvania	04
I/M/O PECO Energy	Office of Consumer Advocate	N/A	Low-income rates	Pennsylvania	04
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	P00042090	Credit and collections	Pennsylvania	04
I/M/O Citizens Gas & Coke/Vectren	Citizens Action Coalition of Indiana	Case 42590	Universal service	Indiana	04
I/M/O PPL Electric Corporation	Office of Consumer Advocate	R00049255	Universal service	Pennsylvania	04
I/M/O Consumers New Jersey Water Company	Division of Ratepayer Advocate	N/A	Low-income water rate	New Jersey	04
I/M/O Washington Gas Light Company	Office of Peoples Counsel	Case 8982	Low-income gas rate	Maryland	04
I/M/O National Fuel Gas	Office of Consumer Advocate	R-00038168	Low-income program design	Pennsylvania	03
I/M/O Washington Gas Light Company	Office of Peoples Counsel	Case 8959	Low-income gas rate	Maryland	03
Golden v. City of Columbus	Helen Golden	C2-01-710	ECOA disparate impacts	Ohio	02
Huegel v. City of Easton	Phyllis Huegel	00-CV-5077	Credit and collection	Pennsylvania	02
I/M/O Universal Service Fund	Public Utility Commission staff	N/A	Universal service funding	New Hampshire	02
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	M-00021612	Universal service	Pennsylvania	02
I/M/O Washington Gas Light Company	Office of Peoples Counsel	Case 8920	Rate design	Maryland	02

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O Consumers Illinois Water Company	Illinois Citizens Utility Board	02-155	Credit and collection	Illinois	02
I/M/O Public Service Electric & Gas Rates	Division of Ratepayer Advocate	GR01050328	Universal service	New Jersey	01
I/M/O Pennsylvania-American Water Company	Office of Consumer Advocate	R-00016339	Low-income rates and water conservation	Pennsylvania	01
I/M/O Louisville Gas & Electric Prepayment Meters	Kentucky Community Action Association	*200-548*	*Low-income energy*	*Kentucky*	*01*
I/M/O NICOR Budget Billing Plan Interest Charge	Cook County State's Attorney	01-0175	Rate Design	Illinois	01
I/M/O Rules Re. Payment Plans for High Natural Gas Prices	Cook County State's Attorney	01-0789	Budget Billing Plans	Illinois	01
I/M/O Philadelphia Water Department	Office of Public Advocate	No docket number	Credit and collections	Philadelphia	01
I/M/O Missouri Gas Energy	Office of Peoples Counsel	GR-2001-292	Low-income rate relief	Missouri	01
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Division of Ratepayer Advocate	T001020095	Telecommunications universal service	New Jersey	01
I/M/O Entergy Merger	Low-Income Intervenors	2000-UA925	Consumer protections	Mississippi	01
I/M/O T.W. Phillips Gas and Oil Co.	*Office of Consumer Advocate*	*R00994790*	*Ratemaking of universal service costs.*	*Pennsylvania*	*00*
I/M/O Peoples Natural Gas Company	Office of Consumer Advocate	R-00994782	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O UGI Gas Company	Office of Consumer Advocate	R-00994786	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O PFG Gas Company	Office of Consumer Advocate	R00994788	Ratemaking of universal service costs.	Pennsylvania	00
Armstrong v. Gallia Metropolitan Housing Authority	Equal Justice Foundation	2:98-CV-373	Public housing utility allowances	Ohio	00
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Division of Ratepayer Advocate	T099120934	Telecommunications universal service	New Jersey	00
I/M/O Universal Service Fund for Gas and Electric Utilities	Division of Ratepayer Advocate	EX00200091	Design and funding of low-income programs	New Jersey	00
I/M/O Consolidated Edison Merger with Northeast Utilities	Save Our Homes Organization	DE 00-009	Merger impacts on low-income	New Hampshire	00
I/M/O UtiliCorp Merger with St. Joseph Light & Power	Missouri Dept. of Natural Resources	EM2000-292	Merger impacts on low-income	Missouri	00
I/M/O UtiliCorp Merger with Empire District Electric	Missouri Dept. of Natural Resources	EM2000-369	Merger impacts on low-income	Missouri	00
I/M/O PacifiCorp	*The Opportunity Council*	*UE-991832*	*Low-income energy affordability*	*Washington*	*00*

CASE NAME	CLIENT NAME	Docket No. (If available)	TOPIC	JURIS.	YEAR
I/M/O Public Service Co. of Colorado	*Colorado Energy Assistance* Foundation	99S-609G	Natural gas rate design	Colorado	00
I/M/O Avista Energy Corp.	Spokane Neighborhood Action Program	UE9911606	Low-income energy affordability	Washington	00
I/M/O TW Phillips Energy Co.	Office of Consumer Advocate	R-00994790	Universal service	Pennsylvania	00
I/M/O PECO Energy Company	Office of Consumer Advocate	R-00994787	Universal service	Pennsylvania	00
I/M/O National Fuel Gas Distribution Corp.	Office of Consumer Advocate	R-00994785	Universal service	Pennsylvania	00
I/M/O PFG Gas Company/Northern Penn Gas	Office of Consumer Advocate	R-00005277	Universal service	Pennsylvania	00
I/M/O UGI Energy Company	Office of Consumer Advocate	R-00994786	Universal service	Pennsylvania	00
Re. PSCO/NSP Merger	Colorado Energy Assistance Foundation	99A-377EG	Merger impacts on low-income	Colorado	99 - 00

OCA Statement No. 4-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
)
v.) Docket Nos. R-2015-2468056
)
COLUMBIA GAS OF)
PENNSYLVANIA)

REBUTTAL TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

July 16, 2015

RECEIVED
2015 AUG -7 PM 12:15
PA PUC
SECRETARY'S BUREAU

OCA Stmt. 4-R
R-2015-2468056
8-4-15
Harrisburg JS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger Colton. My business address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY SERVED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Mitchell Miller on behalf of CAUSE-PA as he addresses universal service issues. More specifically, my Rebuttal Testimony will respond to Mr. Miller's testimony on the following issues:

- First, the "continued legitimacy" of the Columbia Gas (Company or CGPA) CAP-Plus program in light of the Company's proposed customer charge increase;
- Second, the recommendation that CGPA increase its coordination between universal service and energy conservation programs; and
- Third, the recommendation to increase outreach for CAP given that only 20% of CGPA's eligible customers participate in CAP.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS FIRST SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to Mr. Miller's testimony which questions the "legitimacy and legality" of CAP-Plus in light of the Company's request to increase the residential fixed monthly customer charge. (Miller Direct, at 21). There is, however, no connection between the customer charge and CGPA's CAP-Plus calculation. The CAP-Plus calculation is directed toward ensuring a fair balance between the affordable bill delivered under the Company's CAP program and the financial burden imposed on non-participants, including low-income non-participants, accruing from the amount of CAP credits provided. According to the Bureau of Consumer Services (BCS) annual report on universal service programs and collections performance, the monthly bill charged o CAP participants is in-line with other Pennsylvania gas utilities. CGPA's CAP bill (i.e., the "asked-to-pay" amount) from CAP participants is the lowest amongst Pennsylvania's eight natural gas utilities.

Moreover, there is no longer any question of the legal basis for the Company's CAP-Plus program. I have been informed by counsel that the PUC's authority to approve a CAP-Plus program was explicitly affirmed by the Pennsylvania courts.

Q. PLEASE DESCRIBE THE PURPOSE OF THE SECOND SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to Mr. Miller's recommendation that CGPA increase the coordination between its CAP and its Low-Income Usage Reduction Program (LIURP). (Miller Direct at 14). Close coordination between CAP and LIURP, for CGPA in particular, generates benefits for both CAP participants and CAP non-participants.

- For CAP participants, the delivery of LIURP services would improve affordability. Only one of CGPA's four CAP payment agreement types is tied to a percentage of income and only 20% of CGPA's CAP participants participate in that part of the program. In contrast, 43% are enrolled in the payment plan where customers are billed the average of their last 12 months of payment, while 30% are enrolled in the Company's percentage of bill program (50% of an equal monthly payment plan). As I explained in my Direct Testimony, "Nearly three-fourths (73%) of CGPA's CAP customers, in other words, will be adversely affected by the Company's proposed increased rates and change in rate design." For this larger part of the CAP population, increased coordination between CAP and LIURP will improve affordability.

For CAP non-participants, the close coordination between CAP and LIURP would reduce the subsidy that non-participants would be responsible for paying. For PIP participants, each dollar of bill reduction would be a dollar of reduced subsidy. For the percentage of bill participants, each dollar of bill reduction would represent a $0.50 reduction in subsidy. The reduction in subsidy can reasonably be expected to be substantial. While CGPA has not calculated the magnitude of this reduction, PGW recently reported the total reduction in CRP subsidies paid by CRP non-participants resulting from LIURP investments in Phase I of its DSM Plan reached $54,631,743 (2014$). The fact that the exact dollar amount that would be experienced by CGPA would somewhat differ from PGW does not detract from the conclusion that the improved coordination recommended by Mr. Miller would result in substantial bill reductions to CAP non-participants.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS THIRD SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to Mr. Miller's concerns about whether CGPA engages in adequate outreach for its universal service programs. (Miller Direct, at 15). Mr. Miller's concerns are well-founded. In the July 8, 2015 Final Order in the proceeding considering the Company's Universal Service and Energy Conservation (USEC) plan (Docket No. M-2014-2424462), the Commission stated in relevant part:

> Although Columbia has not yet neared its CAP enrollment limit, we questioned whether maintaining this limit is appropriate. *In recent USECP proceedings, the Commission has encouraged utilities to increase CAP enrollment and remove limits* We recently directed UGI Utilities, Inc.-Gas Division, UGI Utilities, Inc.-Electric Division, UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc. (collectively referred to as UGI) to remove CAP enrollment limits. *See UGI 2014-2017 USECP Final Order*, Docket No. M-2013-2371824 (January 15, 2015), at 12-14. We encouraged Columbia to be proactive to avoid situations where it would deny CAP enrollment over that maximum number for low-income households.

(Final Order, at 19) (emphasis added, citations deleted). This acknowledged encouragement for "utilities to increase CAP enrollment" comes outside the context of increased rates, including the proposal to increase the proportion of the bill that low-income customers are not able to reduce by reducing their usage, as advanced by CGPA in this proceeding. Just as the Commission indicated this month in the Company's USEC proceeding, and recognizing the compounded need for increased CAP enrollment created by the proposed rate increase and change in rate design, I recommend that the Commission favorably act upon Mr. Miller's recommendations regarding expanded universal service outreach.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

210257

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket No. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Rebuttal Testimony, OCA St. No. 4-R, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, and Colton
34 Warwick Road
Belmont, Ma 02478

DATED: July 16, 2015

OCA Statement No. 4-S

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
)
v.) Docket Nos. R-2015-2468056
)
COLUMBIA GAS OF)
PENNSYLVANIA)

SURREBUTTAL TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

RECEIVED
2015 AUG -7 PM 12 15
PA PUC
SECRETARY'S BUREAU

July 28, 2015

OCA Stmt. 4-S
R-2015-2468056
8-4-15
Harrisburg

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger Colton. My business address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY FILED DIRECT AND REBUTTAL TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. The purpose of this surrebuttal testimony is to respond to portions of the rebuttal testimonies of Columbia's witnesses Mark Balmert (CPA Statement 111-R) and Nancy Krajovic (CPA Statement 112-R) regarding their response to the recommendations that I made in my direct testimony.

Additionally, I will address the July 8, 2015 Final Order of the Pennsylvania Commission in the Columbia Gas Universal Service and Energy Conservation ("USEC") proceeding at Docket No. M-2014-2424462, which requested that the parties in the USEC proceeding address the Company's current practice of recovering a portion of its Hardship Funds through the USP Rider in this immediate proceeding.

Section 1. The Relationship of Income and Usage.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. In this section of my Surrebuttal Testimony, I respond to the Rebuttal Testimony of Columbia Gas witness Balmert regarding the relationship between income and usage. Mr. Balmert presents a Table in his Rebuttal Testimony, from which he concludes that in 10 of the 12 categories examined by the Company, low-income customers use more, not less than their higher income counterparts. In nine of those instances, however, "low-income" status is demarcated in Mr. Balmert's analysis by participation in the Company's Customer Assistance Program (CAP). Mr. Balmert does not acknowledge that CAP, by design, is directed toward higher usage customers. When customers have lower consumption, and thus lower energy burdens, they will not participate in CAP because they would receive no benefit from CAP (i.e., their bill at standard residential rates would be less than their CAP bill). It is thus not surprising, when one focuses (by program design) a program on higher use low-income customers, that their "mean annual usage" would reflect that program design feature.

Neither does Mr. Balmert's comparison of "customers who are not confirmed low-income" to his "low-income categories" support his conclusion that low-income customers have higher usage than other customers. Someone who is "not confirmed low-income" is not necessarily "higher income." A sizable portion of low-income customers exist who would also fall into that category. Mr. Balmert's use of that "not confirmed low-income" population as a surrogate for "higher income" is simply in error.

Q. DO YOU HAVE ANY FINAL RESPONSE TO MR. BALMERT?

A. Yes. The fact is that numerous federal agencies have examined the relationship between natural gas usage and income. As I previously discussed in my Direct Testimony, the Department of Energy has reached the conclusion that low-income status is related to low use status. In addition, the Department of Labor, in its Consumer Expenditures Survey, has found that as income increases, so, too, do natural gas bills increase. The federal LIHEAP office, in its annual Home Energy Notebook, finds that low-income customers have lower natural gas consumption. In a 2009 study I performed of Pennsylvania-specific Census data outside of the context of a rate case, I found that low-income status and low use status were related.

On a flawed definition of low-income, and using a population which by design excludes low-use customers, Mr. Balmert rejects all of this information. Mr. Balmert instead argues that he would have the Commission find that the U.S. Department of Energy, the U.S. Department of Labor, the U.S. LIHEAP office, and the U.S. Census Bureau are *all* wrong when they *all* find that low-income status is associated with low-usage status. The significance of the above data is not simply that every agency reporting data reaches the same conclusion. The significance lies in the fact that national data, regional data and state-specific data all reach the same conclusion. The significance lies in the fact that all of the data generated on the question by federal agencies reach the same conclusion (i.e., that low-income status is associated with low-use status).

Section 2. LIURP Administrative Costs

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Company witness Krajovic as that testimony relates to collecting internal administrative dollars for the Company's Low-Income Usage Reduction Program (LIURP) through the Company's universal service rider (Rider USP). I conclude that internal staff costs should be included in base rates.

Ms. Krajovic provides somewhat conflicting testimony. She states that I am incorrect when I "appear[...] to view" Company's rate case as including "internal administrative costs associated with LIURP." (CPA Statement 112-R, at 53). She shortly thereafter states, however, that the Company's entire "LIURP spending level" is collected through Rider USP. She specifically states "those annual spending levels include all internal administrative costs. . ." (CPA Statement 112-R, at 54). They should not.

Q. DO YOU DISPUTE WHETHER COLUMBIA GAS HAS THE AUTHORITY TO RECOVER INTERNAL ADMINISTRATIVE COSTS?

A. No. Columbia Gas has the authority to recover its LIURP administrative costs. Neither Section of the Pennsylvania Code cited by Ms. Krajovic (52 Pa. Code §58.5; 52 Pa. Code § 58.2), however, mandate that those costs be collected through Rider USP. Nor does the fact that the settlement of Columbia's 2008 base rate case allowed the recovery of internal administrative costs through Rider USP govern this proceeding. Indeed, if the question of whether the Company was permitted to recover internal administrative costs through Rider USP was not in issue, at that time, it would not need to have been subject to "settlement." That settlement certainly does not bind future ratemaking treatment. In fact, as with most settlements, the settlement specifically provides that the principles made subject to settlement therein are not to be cited as precedent for future litigation.

Q. IS THE FACT THAT INTERNAL ADMINISTRATIVE COSTS ARE SUBJECT TO "SPECIFIC ACCOUNTING IDENTIFIED" AND ARE SUBJECT TO AUDIT IN THE RIDER USP RECONCILIATIONS RELEVANT TO YOUR ARGUMENT?

A. No. The audits of universal service costs in the annual 1307(e) reconciliation proceeding (through which the Rider USP is reconciled with universal service expenditures) simply examine whether the claimed universal service costs have been incurred. Those audits do not examine, nor do they consider, whether those costs are costs that may have been included in the revenue requirement presented in the Company's last base rate case.

Q. DOES MS. KRAJOVIC'S TESTIMONY IDENTIFY THE VERY ISSUE THAT SHOULD GIVE RISE TO REQUIRING INTERNAL ADMINISTRATIVE COSTS TO BE COLLECTED THROUGH BASE RATES?

A. Yes. The principle at issue in this case is not a minor one. In recovering costs as "universal service" costs through Rider USP, Columbia Gas should be allowed to recover *only* the incremental costs specifically incurred because of the existence of the universal service program. To be recovered through Rider USP, in other words, the costs must be new costs. Moreover, the costs must pass a "but-for" test (i.e., the costs would not have been incurred but for the existence of the universal service program). In contrast to this important cost recovery principle, Ms. Krajovic argues that the Company "reserves the right to replace. . .external costs recovered through the Rider with internal administrative costs that would be reflected in the Rider, not in distribution rates." (CPA Statement 112-R, at 56). As Ms. Krajovic concedes in this statement, those "internal administrative costs" may already be "in distribution rates." If and to the extent that they are, they should not be collected through Rider USP. Moreover, in Ms. Krajovic's assertion that it "reserves the right" to substitute internal costs for external costs, she fails to acknowledge the limitation that costs to be collected through Rider USP must be incremental costs as limited by the but-for test I state above. Her testimony asserting the "right" to substitute internal administrative costs for external administrative costs places no limitation whatsoever on whether the Company can redesignate costs included in the revenue requirement in its most recent base rate case as universal service "administrative" costs and collected anew through the Rider USP.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that the Commission should abide by the principle that universal service costs collected through a universal service rider (which is Rider USP for Columbia Gas) are to be limited to incremental costs that would not have been incurred by the Company but-for the existence of the universal service program. Any reasonable application of that principle would require that universal service "internal administrative" costs should be collected in base rates. I conclude that the recommendations I advance in my Direct Testimony should be adopted.

Section 3. Hardship Fund Cost Recovery.

Q. EARLIER IN YOUR TESTIMONY YOU STATED THAT THE COMMISSION REQUESTED THAT THE PARTIES ADDRESS THE RECOVERY OF HARDSHIP FUNDS THROUGH THE USP RIDER IN THIS PROCEEDING. PLEASE EXPLAIN.

A. As a part of Columbia's settlement in the 2012 base rate proceeding at Docket No. R-2012-2321748, the parties agreed to allow Columbia Gas to collect $375,000 for its Hardship Fund through the Company's Universal Service Rider. CGPA added this cost to its USP rider as a part of the 2012 base rate proceeding to address the loss of the existing funding stream that occurred when the Company cancelled its gas purchase contract with Citizens Energy Corporation (Citizens).

On July 8, 2015, the Commission entered a Final Order in Columbia's proposed 2015-2018 Universal Service and Energy Conservation Plan (USECP, or Plan), in Docket No. M-2014-2424462. In that Order, the Commission stated:

> Although we did not propose to amend Columbia's funding mechanism for its Hardship Fund program in the Tentative Order, we invited comments from interested parties on whether monies for Hardship Fund grants should be recovered, and if so, how.
>
> . . .
>
> Although funding a Hardship Fund program through employee, customer, and stockholder contributions is less consistent than a flat charge added to Columbia's USP Rider, other NGDCs and the EDCs are able to fund their programs using only voluntary

> resources. We are not persuaded that Columbia cannot do so as well.
>
> We agree with OCA that the Commission and relevant parties should address this issue through Columbia's current base rate proceeding at Docket No. R-2015-2468056.

Q. WHY DID YOU NOT INCLUDE THIS DISCUSSION IN YOUR DIRECT TESTIMONY?

A. The PUC's approval of addressing this issue in the current base rate case was just granted on July 8, 2015, after the deadline for filing Direct Testimony.

Q. ARE HARDSHIP FUNDS GENERALLY COLLECTED THROUGH A UNIVERSAL SERVICE RIDER?

A. No. Hardship Fund program dollars are usually made up of Company shareholder contributions (either voluntary or matching) and voluntary customer contributions. Typically, these amounts are not recovered through the Universal Service Rider. Columbia's recovery of the $375,000 through the Universal Service Rider occurred in order to fill the gap left by the cancellation of the Company's contract with Citizens and arose as a result of a negotiated settlement of the 2012 base rate proceeding.

Q. DO YOU AGREE WITH THE COMPANY COLLECTING A PORTION OF ITS HARDSHIP FUNDS THROUGH THE USP RIDER?

A. No. Hardship Funds should not be collected through a universal service rider.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR OBJECTION WITH HARSHIP FUNDS BEING RECOVERED THROUGH THE USP RIDER.

A. I have several objections to paying for hardship funds with ratepayer dollars collected through the universal service rider.

First, the 2012 agreement to collect $375,000 in additional hardship funds through the universal service rider was a temporary response to unusual circumstances. The cancellation of the aggregation contract that had generated those dollars raised a concern that the Company would not have sufficient time to develop alternative fundraising mechanisms to replace those dollars in a timeframe that would support the ongoing services which those dollars supported. That response to those exigencies which existed at the time, however, was not intended to create a new permanent responsibility on the part of ratepayers to support the Company's hardship fund through mandatory ratepayer dollars.

Second, hardship fund contributions have historically been voluntary contributions by utility ratepayers. As voluntary contributions, those funds should be matched with investor dollars. In this fashion, there is a sharing of the cost of the hardship fund between willing ratepayer contributors and investors. Indeed, an important part of the outreach for ratepayer contributions involves the fact that their contribution will be matched by the Company. In contrast, the $375,000 included in the universal service rider does not appear to generate a corresponding $375,000 matching grant from investors. As a result, to include the $375,000 as an "expense" to be borne by ratepayers is a fundamental restructuring of the support of utility hardship funds.

Third, hardship fund contributions are not used to support internal Company-generated universal service programming. Instead, hardship funds are provided –albeit for funds dedicated to be repaid to the Company—to external agencies which determine the program parameters regarding to whom, for what purposes, and under what circumstances "hardship" grants will be made. To this extent, hardship funds differ from traditional "universal service" programs administered by the Company such as the Customer Assistance Program ("CAP") or Low-Income Usage Reduction Program ("LIURP").

Finally, hardship funds are distributed based on temporary emergency needs. They are not intended to address the need for ongoing assistance occasioned by chronic poverty. Those ongoing needs are to be addressed by the Company's universal service programs such as CAP and LIURP. In contrast, the need for a hardship fund grant might be caused by temporary interruptions in income due to illness or disability; due to unexpected and extraordinary household expenses, whether it involves medical expenses or a housing or auto repair; due to unexpectedly high bills due to severe weather. In my capacity as administrator of my community's local fuel fund, I personally know that the need for hardship fund grants frequently transcends mere income issues. While these needs are certainly real, they do not represent the universal service problems that are intended to be addressed using ratepayer funds collected through the Company's universal service rider.

Q. WHAT DO YOU RECOMMEND FOR THE TREATMENT OF THE $375,000 HARDSHIP FUND CONTRIBUTION?

A. Because this issue is being addressed for the first time in this proceeding towards the end of the litigation schedule and alternative funding has not been developed, I am recommending that the current recovery mechanism agreed to in the 2012 settlement be continued until Columbia's next base rate case. As I discuss more below, however, Columbia should be directed to ramp up its fundraising efforts and continue to seek a replacement for this funding. The Company should then be directed to address this issue in its next base rate case.

Continuing with the 2012 settlement at this time avoid placing the Company in a position to either immediately ramp-up its Hardship Fund fundraising, or to experience a significant drop in Hardship Fund revenue. By reserving this issue for the Company's next rate case, the Company will have the opportunity to plan for the possibility of the Hardship Fund dollars being removed from the USP Rider.

Q. DO YOU HAVE SUGGESTIONS AS TO WHAT THE COMPANY CAN DO NOW TO PREPARE FOR THE POSSIBILITY THAT THE HARDSHIP FUNDS COULD BE REMOVED FROM THE USP RIDER?

A. Yes. Columbia Gas should engage in a planning process that would generate additional dollars of Hardship Fund contributions. The planning process should seek first a new aggregation partner that would provide a contribution that would mirror, in whole or substantial part, that contribution that was lost through the cancellation of the Citizens contract. In addition, based on my past experience as a member of the Board of Directors of the National Fuel Funds Network (NFFN), the national industry association of hardship funds, without limitation, CGPA could pursue fundraising techniques that include (for example):

- CGPA should actively solicit contributions from all customer classes. Given that hardship funds are voluntary contributions, they need not be limited to residential solicitations.
- CGPA should ensure that customers who pay electronically, either on-line or via electronic billing, not simply customers receiving paper bills, have the opportunity to contribute to the hardship fund.
- CGPA should actively solicit hardship fund contributions that are not limited to on-bill contributions. Collaborations with local sports teams, for example, have been found to be successful. Dollar Energy has a Pittsburgh-based annual "telethon," in which I am an annual participant, to support its local hardship fund efforts.
- CGPA should actively solicit hardship fund contributions from unions, contractors and suppliers. Hardship fund contributors need not be limited to CGPA customers.

My point in making these suggestions is not to limit the Company's possible alternatives to these specific ideas. To generate and implement additional ideas, CGPA should routinely meet with low-income service providers; union representatives; civic, religious and nonprofit emergency funds; and other stakeholders, to assess how, if at all, fundraising efforts directed toward supporting the Company's hardship fund might be enhanced.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

210521

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
	:	Docket No. R-2015-2468056
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 4-S, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, and Colton
34 Warwick Road
Belmont, Ma 02478

DATED: July 28, 2015

OCA Exhibit No. 1

Question No. OCA 13-001
Respondent: B.E. Elliott
M.P. Balmert
Page 1 of 1

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

OCA – Set 13

Question No. OCA 13-001:

For each of the 10 largest non-MLS/MLDS customers, please identify annual throughput, design day demand, and the distance between the customers' most upstream meter and the meter of the next closet upstream customer.

Response:

Rank	Design Day (Dth)	Throughput (Dth)	Distance (ft) To Next Meter
1	3,827	1,267,163.0	7,317
2	6,491	1,206,288.5	1,556
3	0	915,331.0	1,661
4	2,029	734,295.0	877
5	2,390	682,045.0	2,017
6	2,326	603,064.0	840
7	1,993	596,890.0	2,009
8	1,843	590,303.0	[1]
9	2,005	569,808.0	2,274
10	1,011	474,148.0	182

[1] There is no next meter, this customer is the only one served off the main that the customer is served off of.

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OCA Exhibit 1
R-2015-2468056
8-4-15
Harrisburg JS

OCA Exhibit No. 2

Question No. OCA 13-002
Respondent: B.E. Elliott
M.P. Balmert
Page 1 of 1

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

OCA – Set 13

Question No. OCA 13-002:

Please identify the number of customers by class, which are served by 2-inch mains.

Response:

The following identifies customers by rate class that are served directly off a 2" main. Although extremely rare, it is possible that customers directly served off a different diameter main could be served down-stream from a 2" main (ie. 1" main) however without a full analysis of every pipe segment Columbia has in its distribution system it is impossible to determine how many customers are fed downstream from a 2" main directly served off a non-2" main.

Also note that although a 2" main cannot serve the entire load requirements of a LDS account some LDS accounts are an aggregate of multiple premises that are served off different size, kind and pressure mains. The 4 accounts listed below consist of 54 premises of which 15 are served off 2" mains and the remainder are served off larger diameter mains.

Rate Class	Customers	Comment
RSS/RDS	118,707	
SGSS/SCD/SGDS	6,211	
SDS/LGSS	69	
LDS/LGSS	4	15 out of 54 premises
MLDS	2	
Total	124,993	

OCA Exhibit 2
R-2015-2468056
8-4-15
Harrisburg JS

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket Nos. R-2015-2468056
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Mark Balmert, being Director of Regulatory Strategy & Support for NiSource Corporate Services Company, hereby state that the information set forth in Columbia's responses to data requests OCA Set XIII Nos. 1 and 2 is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth therein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: August 3, 2015

Mark Balmert
Mark Balmert

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
:
: Docket Nos. R-2015-2468056
v. :
:
Columbia Gas of Pennsylvania, Inc. :

VERIFICATION

I, Brian E. Elliott, being Manager, Regulatory Strategy and Support for NiSource Corporate Services Company, hereby state that the information set forth in Columbia's responses to data requests OCA Set XIII Nos. 1 and 2 is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth therein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: August 3, 2015

Brian E. Elliott
Brian E. Elliott