

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

)
)
) Docket Nos. R-2012-2321748
) M-2012-2323645
)

DIRECT TESTIMONY

OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 4, 2013

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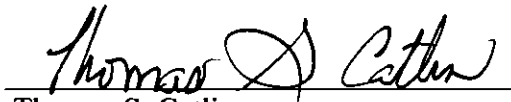
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Docket Nos. R-2012-2321748
M-2012-2323645

VERIFICATION

I, Thomas S. Catlin, hereby state that the facts above set forth in my Direct Testimony (OCA Statement No. 1) and Surrebuttal Testimony (OCA Statement 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:


Thomas S. Catlin

Consultant Address: Exeter Associates, Inc.
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DATED: 02/08/2013

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Qualifications

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

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science Degree in Water Resources Engineering and Management from Arizona State University (1976). Major areas of study for this degree included pricing policy, economics, and management. I received my Bachelor of Science Degree in Physics and Math from the State University of New York at Stony Brook in 1974. I have also completed graduate courses in financial and management accounting.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From August 1976 until June 1977, I was employed by Arthur Beard Engineers in Phoenix, Arizona, where, among other responsibilities, I conducted economic feasibility, financial and implementation analyses in conjunction with utility construction projects. I also served as project engineer for two utility valuation studies.

From June 1977 until September 1981, I was employed by Camp Dresser & McKee, Inc. (CDM). Prior to transferring to the Management Consulting Division of CDM in April 1978, I was involved in both project administration and design. My project administration responsibilities included budget preparation as well as labor

1 and cost monitoring and forecasting. As a member of CDM's Management
2 Consulting Division, I performed cost of service, rate, and financial studies involving
3 approximately 15 municipal and private water, wastewater, and storm drainage
4 utilities. These projects included: determining total costs of service; developing
5 capital asset and depreciation bases; preparing cost allocation studies; evaluating
6 alternative rate structures and designing rates; preparing bill analyses; developing cost
7 and revenue projections; and preparing rate filings and expert testimony.

8 In September 1981, I accepted a position as a utility rates analyst with Exeter
9 Associates, Inc. I became a principal and vice-president of the firm in 1984. Since
10 joining Exeter, I have continued to be involved in the analysis of the operations of
11 public utilities, with particular emphasis on utility rate regulation. I have been
12 extensively involved in the review and analysis of utility rate filings, as well as other
13 types of proceedings before state and federal regulatory authorities. My work in
14 utility rate filings has focused on revenue requirements issues, but has also addressed
15 service cost and rate design matters. I have also been involved in analyzing affiliate
16 relations, alternative regulatory mechanisms, and regulatory restructuring issues.
17 This experience has involved electric, natural gas transmission and distribution, and
18 telephone utilities, as well as water and wastewater companies.

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

21 A. Yes. I have previously presented testimony on more than 250 occasions before the
22 Federal Energy Regulatory Commission and the public utility commissions of
23 Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Idaho,
24 Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New
25 Jersey, Ohio, Oklahoma, Rhode Island, Utah, Virginia and West Virginia, as well as

1 before this Commission. I have also filed rate case evidence by affidavit with the
2 Connecticut Department of Public Utility Control and have appeared as a witness on
3 behalf of the Louisiana Public Service Commission before the Nineteenth Judicial
4 District Court. A complete listing of my previous testimony is included as Appendix
5 A.

6 Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

7 A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate (OCA).
8

9 **Purpose and Conclusion**

10 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

11 A. I have been asked by the OCA to determine the level of revenues that Columbia Gas
12 of Pennsylvania, Inc. (Columbia or the Company) should be authorized in this
13 proceeding. In this testimony, I present my findings regarding Columbia's test year
14 rate base and net operating income at present rates. Based on these amounts, I have
15 determined the revenues that are required to generate the overall rate of return on rate
16 base recommended by Mr. Matthew I. Kahal on behalf of the OCA.

17 Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR
18 TESTIMONY?

19 A. Yes, I have. Schedules TSC-1 through TSC-17 are attached to my testimony. These
20 schedules present my findings and recommendations regarding Columbia's test year
21 revenue requirements.

22 Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE
23 COMPANY'S REVENUE REQUIREMENT.

24 A. As shown on Schedule TSC-1, I have determined the Company has a revenue
25 deficiency \$43,436,513 for the fully forecasted future test year or rate year ended

1 June 30, 2014. This represents a difference of \$33,874,540 compared to Columbia's
2 requested increase of \$77,311,053. This is the amount by which revenues exceed
3 those required to generate an overall rate of return of 7.49 percent after accounting for
4 the OCA's adjustments to Columbia's claimed rate base and operating income. The
5 return of 7.49 percent represents Mr. Kahal's finding regarding the Company's
6 overall rate of return.

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

12 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

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

18
19 **Fully Forecasted Rate Year**

20 Q. WHAT TIME PERIOD HAS COLUMBIA USED AS THE BASIS FOR
21 DETERMINING ITS REVENUE REQUIREMENTS IN THIS
22 PROCEEDING?

23 A. Columbia has used the 12 months ending June 30, 2014 as the test period for
24 determining its revenue requirements in this proceeding. Columbia refers to this as

1 the fully forecasted rate year (FFRY or rate year). The use of a fully projected future
2 test year or rate year is permitted pursuant to Act 11 of 2012 (Act 11).

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

5 A. No. The use of a fully projected future test year or rate year is intended to allow rates
6 to be set to reflect the costs that will be incurred during the first year the rates will be
7 in effect. Columbia has overstated its future rate year cost of service by reflecting
8 costs at end of FFRY levels rather than at the levels of costs that will be experienced
9 during the rate year. Rather than reflecting costs that will be incurred during the rate
10 year ending June 30, 2014, Columbia has reflected costs that will be incurred as of
11 July 1, 2014.

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

14 A. Yes. One example is Columbia has included projected plant in service as of June 30,
15 2014 in rate base and has calculated depreciation expense based not only on the
16 balance of plant in service as of June 30, 2014, but also on the balance of construction
17 work in progress (CWIP) as of that date. If accepted, this proposal would result in
18 Columbia earning a return beginning on the first day of the test year on plant that will
19 not be in service and, hence, will not be used and useful for up to one year later.
20 Similarly, the Company would be allowed to recover a full year of depreciation
21 expense on plant that will not be in service for the entire rate year and, in the case of
22 CWIP, not even in service during the rate year.

23 Another example is Columbia has adjusted wages to include the full annual
24 effect of wage increases that are scheduled to be granted as late as June of 2014. As a

1 result, Columbia's rate year revenue requirement is overstated by including wages
2 that are not being paid for the first 11 months of the rate year.

3 A third example is corporate insurance expense. Columbia has adjusted the
4 costs associated with property and liability insurance to reflect the premiums that will
5 be in effect as of July 1, 2014 and, in some cases, November 1, 2014. Hence,
6 Columbia has reflected insurance premiums that will not even be in effect until after
7 the rate year ending June 30, 2014.

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

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

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

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

10

11

Average Rate Base

12 Q.

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

15 A.

In its filing, Columbia has reflected plant in service, accumulated depreciation, and
16 accumulated deferred income taxes (ADIT) at projected June 30, 2014 levels in
17 determining its FFRY rate base claim. As explained previously, including the end of
18 rate year plant in service and related balances in rate base would result in Columbia
19 earning a return on a rate base that exceeds the Company's actual investment during
20 the rate year. To reflect the Company's projected investment over the course of the
21 first year the rates in this case will be in effect, I have adjusted plant in service,
22 accumulated depreciation and ADIT included in rate base to reflect the average
23 balances during the rate year.

1 Q. CAN YOU ILLUSTRATE HOW THE COMPANY'S PROPOSED RATE
2 BASE WILL RESULT IN COLUMBIA EARNING A RETURN ON PLANT
3 THAT IS NOT IN SERVICE?

4 A. Yes, Columbia has included projected plant in service as of June 30, 2014 in the
5 amount of \$1,447,108,215 in its claimed FFRY rate base. In comparison, the
6 Company's projected plant in service in each month of the rate year and the amount
7 by which those balances are less than Columbia's claim are shown in the following
8 table.

9

TABLE A		
Rate Year Plant in Service (\$ Millions)		
<u>Month</u>	<u>Projected Month End Balance</u>	<u>Difference vs. 6/30/14 Balance</u>
June 2013	\$1,321.2	\$ (155.9)
July	1,336.1	(141.0)
August	1,351.2	(125.9)
September	1,366.4	(110.7)
October	1,381.6	(95.5)
November	1,394.4	(82.7)
December	1,407.7	(69.4)
January 2014	1,415.6	(61.5)
February	1,423.3	(53.8)
March	1,434.0	(43.1)
April	1,450.5	(26.6)
May	1,464.4	(12.7)
June 2014	1,477.1	-

10

11 As can be seen from this table, setting rates based on June 30, 2014 plant would result
12 in Columbia earning a return on plant in service well in excess of the levels of plant
13 investment that Columbia projects will be in service during the rate year.

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

3 A. I have calculated the average balances of plant in service, accumulated depreciation
4 and ADIT based on the 13-month average balance of each item for the period from
5 June 30, 2013 through June 30, 2014. In developing these average balances, I have
6 accepted and utilized the monthly balances projected by Columbia.

7 Q. WHY HAVE YOU NOT MADE AN ADJUSTMENT TO THE ELEMENTS
8 OF RATE BASE OTHER THAN PLANT, ACCUMULATED
9 DEPRECIATION AND ADIT?

10 A. No adjustment to the other elements of rate base was necessary because, with the
11 exception of plant in service, accumulated depreciation and ADIT, all other elements
12 of the Company's claimed rate base already reflect average rate year balances.

13 Q. HAVE YOU PREPARED A SCHEDULE THAT SHOWS THE EFFECT OF
14 ADJUSTING COLUMBIA'S CLAIMED RATE BASE TO REFLECT THE
15 13-MONTH AVERAGE BALANCES OF PLANT IN SERVICE,
16 ACCUMULATED DEPRECIATION AND ADIT DURING THE FIRST
17 YEAR THAT THE RATES APPROVED IN THIS PROCEEDING WILL BE
18 IN EFFECT?

19 A. Yes. Schedule TSC-5 presents my adjustment to reflect the average rate year
20 balances of plant, accumulated depreciation and ADIT. As shown there, the net
21 effect of this adjustment is to reduce rate base by \$60,130,616.

22

23 **Salaries and Wages for Existing Employees**

24 Q. HOW HAS COLUMBIA DEVELOPED ITS RATE YEAR ESTIMATE OF
25 SALARIES AND WAGES FOR COMPANY EMPLOYEES?

1 A. Columbia has separately developed projections of rate year salaries and wages for its
2 existing employees as of the end of the historic test year (HTY) on May 31, 2012, and
3 for the 55 new employees it projects will be added by December 31, 2012. I will
4 address my adjustments to the wages for existing employees first and will then
5 address the wages claimed for new employees in the subsequent section of my
6 testimony.

7 With regard to the determination of the rate year claim for existing employees,
8 Columbia first adjusted HTY salaries and wages to exclude severance costs and to
9 reflect a five-year historical percentage of wages charged to O&M. The Company
10 then adjusted salaries and wages to annualize the wage increases granted during the
11 HTY as well as to reflect the full annual effect of the wage increases projected to
12 occur during the period from the end of the HTY through the end of the rate year on
13 June 30, 2014.

14 Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO MAKE TO
15 COLUMBIA'S CLAIMED RATE YEAR SALARIES AND WAGES FOR
16 EXISTING EMPLOYEES?

17 A. I am proposing to make two adjustments to the salaries and wages that Columbia has
18 included in its FFRY claim for existing employees. First, I am proposing to adjust
19 the Company's claim to reflect the salaries and wages that will be paid during the rate
20 year rather than those included in Columbia's claim based on end of rate year wage
21 rates. Second, I am proposing to update the percentage of salaries and wages charged
22 to operation and maintenance (O&M) expense to reflect the most recent experience
23 available. In addition, in calculating my recommended allowance for rate year
24 salaries and wages for existing employees, I have incorporated the revisions that
25 Columbia has identified as being necessary to its filed claim to recognize that the rate

1 year union wage increases will be 3 percent rather than the 2 percent initially
2 included.

3 Q. PLEASE EXPLAIN YOUR FIRST ADJUSTMENT TO SALARIES AND
4 WAGES FOR EXISTING EMPLOYEES.

5 A. In developing its projected rate year revenue requirements, Columbia adjusted
6 salaries and wages for existing employees to end of rate year levels. For union
7 employees, Columbia reflected the full annual effect of wage increases scheduled to
8 take effect in September 2013, November 2013 and April 2014. For non-union
9 employees, the Company has reflected the full annual effect of projected wage
10 increases to become effective on June 1, 2014.¹

11 Including the full annual effect of wage increases scheduled to take effect as
12 late as April and June 2014 results in the overstatement of the costs that Columbia
13 will incur during the first year that rates approved in this case will be in effect. This
14 overstatement of costs would, if accepted, allow Columbia to recover from ratepayers
15 costs that it is not incurring and, in turn, result in excess earnings. In order to
16 properly reflect the costs that Columbia will incur during the rate year, I have
17 adjusted wages to reflect the salaries and wages that Columbia has projected it will
18 pay to existing employees during the 12 months ended June 30, 2014.

19 Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATED TO THE
20 PERCENTAGE OF WAGES CHARGED TO O&M EXPENSE.

21 A. Columbia states that the percentage of wages charged to O&M during the historical
22 test year is not representative of the percentage of wages that will be charged to O&M
23 prospectively during the rate year. Therefore, Columbia used a five-year historical

¹ At the time Columbia filed its case, non-union wage increases were expected to occur on March 1, beginning in 2013. The effective date has now been moved back to June 1, which is the date those wage increases have historically taken place.

1 average percentage of wages charged to O&M over the period 2007 through 2011 as
2 the percentage of wages that will be charged to O&M during the rate year.

3 I have accepted Columbia's proposal to utilize a five-year historical average
4 to calculate the percentage of wages charged to O&M for the rate year. However, I
5 am proposing to update to reflect experience for the five years from 2008 through
6 2012 instead of 2007 through 2011. Inclusion of the results for 2012 instead of 2007
7 is appropriate to reflect the most recent operations of the Company. This change
8 results in a percentage of wages charged to O&M of 66.02 percent compared to 67.47
9 percent claimed by Columbia. Both of these percentages are well above the 61.53
10 percent of wages charged to O&M during the HTY.

11 Q. HAVE YOU BEEN ABLE TO REFLECT EXPERIENCE FOR ALL OF
12 2012?

13 A. No. I have used the percentage of wages charged to O&M for the 12 months ending
14 October 2012, the most recent 12 months available to me at the time I prepared this
15 testimony. It would be appropriate for Columbia to update the percentage to reflect
16 experience for the 12 months ended December 31, 2012 at the time it files its rebuttal
17 testimony.

18 Q. HAVE YOU PREPARED A SCHEDULE SHOWING THE EFFECT OF
19 YOUR TWO CHANGES TO RATE YEAR SALARIES AND WAGES FOR
20 EXISTING EMPLOYEES?

21 A. Yes. Schedule TSC-6 presents the calculation of my adjustment. Column (A) of that
22 schedule shows the Company's filed claim for the salaries and wages of existing
23 employees. Column (B) presents the Company's updated claim based on the 3
24 percent rather than 2 percent rate year increase for union employees and other related

1 charges.² My calculation of salaries and wages is presented in Column (C). I have
2 used the Company's revised claim as the starting point for my calculation. The first
3 adjustment from Columbia's updated claim is shown on line 3 where I have revised
4 the adjustment to HTY wages to reflect 66.02 percent of wages charged to O&M
5 versus 61.55 percent in the HTY and 67.47 percent used by Columbia. Lines 8 and 9
6 show the differences between total rate year wages (before applying the O&M
7 percentage) under Columbia's proposal to reflect the full annual effect of rate year
8 wage increases and my recommendation to reflect the portion of those wage increases
9 that will be paid during the rate year ended June 30, 2014. Lines 10 through 12 show
10 the calculation of wage increases subsequent to the HTY that will be charged to
11 O&M under the Company's initial and updated claims and my recommendation. As
12 shown in Column (D), the overall effect of my recommended changes is to reduce
13 rate year wage expense by \$747,188 compared to Columbia's filed claim. (The
14 reduction to Columbia's updated request is \$967,161.)

15
16 **New Columbia Employees**

17 Q. WHAT CLAIM HAS COLUMBIA MADE FOR NEW COMPANY
18 EMPLOYEES?

19 A. Columbia has included salaries and wages for 55 new employees that it expects to
20 add by December 31, 2012. As with existing employees, the salaries and wages that
21 Columbia included for these new employees were based on projected annualized
22 wages as of the end of the rate year. Columbia estimated the portions of the new
23 employees' wages that will be charged to O&M expense based on the job

² This updated claim was provided in the supplemental response to OCA I-15.

1 responsibilities of the employees being added rather than based on an O&M
2 percentage for the Company as a whole.

3 Q. HAS THE COMPANY PROVIDED AN UPDATE TO ITS ESTIMATE OF
4 WAGES FOR NEW EMPLOYEES?

5 A. Yes. In its supplemental response to OCA I-15, Columbia revised its request for new
6 employees to reflect: updated salary information; the eligibility of union employees
7 for a wage increase during the FTY ended May 31, 2013 based on the hire date
8 compared to the contract adjustment date for the specific union involved³; a 3.0
9 percent instead of a 2.0 percent wage increase in the rate year for union employees;
10 and the changed timing of non-union wage increases from March to June.

11 Q. WHAT CHANGES ARE YOU PROPOSING TO MAKE TO COLUMBIA'S
12 FILED CLAIM OF THE SALARIES AND WAGES FOR NEW
13 EMPLOYEES?

14 A. I have utilized the updated wages and salaries provided in the supplemental response
15 to OCA I-15 as the starting point for my analysis. I have then adjusted this claim to
16 reflect only the wages expected to be paid during the rate year to these new
17 employees rather than including the full annual effect of all wage increases granted
18 during the rate year.

19 Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENT?

20 A. As shown on Schedule TSC-7, limiting the wages for new employees to those that are
21 expected to be paid during the rate year reduces rate year salaries and wages by
22 \$266,639. Of the total, \$254,915 is the result of Columbia's updating of the wages
23 for new employees.

³ Columbia calculated the projected wages for new employees by increasing their starting wages by the wage rate increases planned for the FTY and the FFRY. Some of the new union employees were hired after the dates of the various union wage increases in the FTY and, hence, no FTY increase was needed for those employees.

1 Q. YOU HAVE INCLUDED THE WAGES FOR ALL 55 NEW EMPLOYEES.
2 HAVE ALL OF THOSE EMPLOYEES BEEN HIRED?

3 A. No. Based on the supplemental response to OCA I-15, only 37 of the 55 employees
4 have been hired as of the time I prepared this testimony. To the extent that the
5 remaining 18 employees have not been hired as of the rebuttal stage of this
6 proceeding, I will consider modifying my recommendation to exclude the new
7 employees that have not been hired.
8

9 **Pension & Benefits Expense**

10 Q. HOW DID COLUMBIA DEVELOP ITS FFRY CLAIM FOR PENSION
11 AND BENEFITS EXPENSE?

12 A. To develop its pension expense (retirement income plan) claim for the FFRY or rate
13 year, Columbia used a three-year average of the contributions in the second half of
14 2011 for the 2010 and 2011 plan years and one-half of the contribution planned for
15 the 2014 plan year. (No contributions have been made in 2012 or are planned for
16 2013.) With regard to other post-employment benefits (OPEBs), Columbia included
17 no claim for ongoing SFAS 106 costs because the plan is overfunded. In addition, the
18 Company has proposed to return the overfunding as of June 30, 2013 to ratepayers
19 over two years. For the SFAS 112 portion of OPEB costs, Columbia has used a five-
20 year historical average of this ongoing expense and has included the continuing
21 amortization of the regulatory asset. For all other benefits, the Company based its
22 claim on the projected calendar year 2014 expense as provided by Aon Hewitt.⁴
23 These projected expenses for all other benefits were further adjusted to reflect
24 amounts for the 55 new employees discussed previously.

⁴ Intercompany benefit billings were left unchanged other than for the change in the percent charged to O&M.

1 Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO MAKE TO
2 COLUMBIA'S CLAIM FOR PENSION AND BENEFITS?

3 A. I have accepted Columbia's claim for OPEB costs, including both the SFAS 106 and
4 SFAS 112 amounts, as well as its claim for intercompany benefits. For pension and
5 other benefits costs, I have adjusted the Company's claim to reflect the costs that
6 Columbia expects to incur during the rate year based on six months of the Aon Hewitt
7 projections for 2013 and six months of the Aon Hewitt projections for 2014. In
8 addition, I have revised the percentage of costs charged to O&M to reflect the most
9 recent five-year average as discussed previously.

10 Q. WHY HAVE YOU UTILIZED ANNUAL EXPENSES BASED ON THE
11 USE OF COSTS FOR SIX MONTHS OF 2013 AND SIX MONTHS OF
12 2014?

13 A. As discussed previously, given that Columbia is now permitted to use a fully
14 forecasted future test year to set rates, it is no longer necessary or appropriate to
15 adjust costs to the levels that will be incurred as of the end of that fully forecasted
16 future test year as was done when rates were set utilizing an FTY that ended around
17 the time rates went into effect. Act 11 allows the use of a fully projected test year
18 that is defined as the 12-month period that begins when the new rates will be placed
19 in effect. Accordingly, the costs used to set rates for the rate year should be those that
20 will be incurred during the first 12 months the rates are in effect beginning July 1,
21 2013, not the 12 months beginning January 1, 2014 as Columbia has proposed.

22 Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR
23 ADJUSTMENT TO USE SIX MONTHS OF COSTS FOR 2013 AND 2014
24 TO DETERMINE PENSION EXPENSE?

1 A. Yes. I have used the Aon Hewitt projections of pension (retirement plan)
2 contributions in 2013 and 2014 to reflect the costs that will be incurred during the rate
3 year. As noted above, no pension contributions are expected in 2012 or 2013, so the
4 three-year average for 2012 through 2014 would be lower than the pension expense I
5 have proposed. In addition, a two-year average of pension contributions for 2010 and
6 2011 was used by the Company in calculating its claimed pension expense for the
7 FTY ending September 30, 2011 in its last rate case. In that same case, in my
8 testimony on behalf of the OCA, I accepted the use of the two-year average, but
9 updated to reflect the actual March 2011 contribution in lieu of the estimate used by
10 Columbia in its filing. Columbia accepted this revision in its rebuttal. I do not
11 believe that it is necessary or appropriate to now use a three-year average that reaches
12 back to 2011 in lieu of reflecting the rate year expense, which is the equivalent of a
13 two-year average for 2013 and 2014.

14 Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENTS?

15 A. As shown on Schedule TSC-8, the effect of adjusting benefits expense to reflect the
16 costs that will be incurred during the rate year as well as to reflect the updated
17 percentage of wages charged O&M is to reduce rate year O&M expense by
18 \$2,973,572.

19

20 **NCSC Labor and Benefits**

21 Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO MAKE TO
22 COLUMBIA'S CLAIM FOR NISOURCE CORPORATE SERVICE
23 COMPANY (NCSC OR SERVICE COMPANY) BILLINGS FOR LABOR
24 AND RELATED COSTS?

1 A. I have made three adjustments to NCSC billings for labor and related costs included
2 by Columbia in its claimed rate year cost of service. First, I am proposing to revise
3 the percentage of labor costs allocated to Columbia to reflect the average during the
4 HTY rather than using the percentage in the last month of the HTY. Second, I am
5 proposing to exclude the costs for the additional employees that NCSC has claimed
6 will be added during the FFRY or rate year. Finally, I have adjusted Columbia's
7 claimed costs to reflect the costs that will be incurred during the rate year rather than
8 the annualized costs as of the end of the rate year. As shown on Schedule TSC-9, the
9 combined effect of these three adjustments to rate year NCSC labor and related costs
10 billed to Columbia is reduction of \$1,101,160.

11 Q. PLEASE EXPLAIN YOUR FIRST ADJUSTMENT RELATED TO THE
12 PERCENTAGE OF NCSC LABOR AND RELATED COSTS ALLOCATED
13 TO COLUMBIA.

14 A. In developing its rate year claim for Service Company billings for labor and related
15 costs, Columbia adjusted actual test year billings to reflect an 11.22 percent allocation
16 of these costs to Columbia. This same percentage allocation was used to determine
17 Columbia's share of each of the FTY and FFRY adjustments to NCSC labor cost
18 billings.

19 The 11.22 percent allocation represents the percentage of NCSC labor and
20 related costs allocated to Columbia in the month of May 2012. However, as
21 acknowledged by Columbia in the response to OCA I-36, the percentage of NCSC
22 labor and related costs allocated to Columbia fluctuates from month to month due to
23 the procedures in place that require NCSC employees to directly bill their time based
24 on projects and assignments. In light of the fact that Columbia's percentage of NCSC
25 costs varies from month to month, it is inappropriate to use a single month to

1 determine the percentage of NCSC labor and related costs billable to Columbia.
2 Therefore, rather than using the percentage for the last month of the HTY as
3 Columbia has done, I have adjusted NCSC labor and related costs to reflect the
4 average annual percentage allocation during the HTY of 10.93 percent.

5 Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT?

6 A. As shown on Schedule TSC-9, adjusting the percentage of NCSC labor and related
7 costs allocated to Columbia from the end of HTY level of 11.22 percent to the annual
8 level for the HTY reduces Columbia's claimed rate year costs by \$488,858.

9 Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EXCLUDE THE LABOR
10 AND RELATED COSTS FOR ADDITIONAL SERVICE COMPANY
11 EMPLOYEES PROJECTED TO BE ADDED DURING THE FFY.

12 A. In developing its estimate of Service Company billings included in its claimed rate
13 year cost of service, Columbia has included wages and related cost for 113 new
14 employees. Of this total, 86 are projected to be added during the FTY ended May 31,
15 2013 and an additional 27 employees to projected to be added by December 31, 2013,
16 the midpoint of the rate year.⁵ As of December 4, 2012, when Columbia responded to
17 I&E-RE-113-D, only 46 of the 86 positions expected to be added in the FTY had
18 been filled and only 11 of the remaining open positions were posted or in the
19 interview stage. I have accepted inclusion of the 86 employees projected to be added
20 during the FTY. However, in light of the significant remaining openings in the pool
21 of new employees to be added during the FTY, I have excluded the wages for the
22 additional NCSC employees included as being added in the rate year.

23 Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT ON THE RATE LEVEL
24 OF NCSC COSTS?

⁵ According to the response to OCA I-44, NCSC projects it will add 29 employees, but only 27 of those employees will work on projects allocable to Columbia.

1 A. As shown on Schedule TSC-9, this adjustment reduces rate year expenses by
2 \$325,511.

3 Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO NCSC LABOR AND
4 RELATED COSTS TO REFLECT THE COSTS THAT WILL BE
5 INCURRED DURING THE RATE YEAR ENDED JUNE 30, 2014.

6 A. Like the costs for its own employees and employee benefits, Columbia's filing
7 reflects the projected level of labor and benefits for NCSC employees based on
8 annualized costs as of the end of the FFRY on June 30, 2014. Similar to my
9 adjustments to Columbia's internal labor and benefit costs that I have explained
10 previously, I have adjusted the amounts billed to Columbia by NCSC for labor and
11 related costs to reflect the amounts expected to be incurred during the rate year. As
12 shown on Schedule TSC-9, this adjustment reduces rate year expenses by \$286,792.

13

14 **Profit Sharing Expense**

15 Q. WHAT ARE THE COMPONENTS OF COLUMBIA'S AND NCSC'S
16 PERFORMANCE BASED COMPENSATION PROGRAMS?

17 A. Columbia and NCSC have three performance based compensation programs of which
18 I am aware. The first is the incentive compensation plan, which is a short-term cash
19 based award program (the cash incentive plan). The second is the performance based
20 equity awards plan, which consists of stock awards that are granted to employees at
21 the vice president level and above, along with certain exempt employees who may
22 receive CEO stock grants. Awards under the cash incentive plan and the equity
23 awards program are based on a combination of achieving corporate or business unit
24 financial goals and achieving non-financial performance measures.

1 In addition to the cash incentive plan and equity awards plan that Columbia
2 considers part of base compensation, Columbia and the Service Company also have a
3 profit sharing plan. The profit sharing plan consists of contributions to a retirement
4 plan for all eligible employees. Profit sharing payments are based solely on the
5 achievement of earnings per share goals.

6 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THE
7 COMPANY'S CLAIMED COSTS FOR ITS PERFORMANCE BASED
8 AWARDS PROGRAMS?

9 A. I am proposing to remove the costs associated with the profit sharing plan because the
10 costs of this plan are based exclusively on achieving business unit and corporate
11 financial goals and, as a result, are not properly recoverable from ratepayers for
12 several reasons. First, if the financial targets are set properly, achieving the necessary
13 performance should be self-supporting. That is, measures that achieve additional cost
14 savings, increase revenue or otherwise improve financial result should generate the
15 necessary income to make the profit sharing payments. Second, profit sharing
16 payments are not dependent on meeting quality of service, efficiency or salary goals.
17 Finally, the incentive to improve financial performance is not necessarily consistent
18 with the interests of Columbia's ratepayers.

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

21 A. As shown on Schedule TSC-10, this adjustment reduces FFRY expense by \$222,825
22 for Columbia employees and by \$107,243 for NCSC employee costs billed to
23 Columbia for a total reduction in rate year O&M of \$330,067.

Phantom Stock

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE PHANTOM STOCK COSTS INCLUDED IN NCSC BILLINGS.

A. Service Company billings to Columbia for the rate year include \$101,981 of Phantom Stock costs. These costs represent dividends on stock issued to certain NiSource executives in conjunction with the acquisition of Columbia by NiSource. I am proposing to remove these costs because they are unrelated to provision of service to Columbia's customers. This adjustment is presented on Schedule TSC-11.

Corporate Insurance

Q. HOW DID COLUMBIA DERIVE ITS CLAIM FOR CORPORATE INSURANCE EXPENSE?

A. Columbia started with what it identified as the property and liability insurance premiums in effect as of May 31, 2012. It then escalated those premiums by five percent (5%) per year for two years to determine the premiums for the FFRY.

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM FOR CORPORATE INSURANCE?

A. No. There are three issues with Columbia's calculation. First, as indicated in the response to OCA VI-4, what Columbia has identified as the premiums in effect as of May 31, 2012 are actually the insurance premiums for the period July 1, 2012 through June 30, 2013 and, in some cases, November 1, 2012 through October 31, 2013. Accordingly, by applying an escalation factor for two years, Columbia has included projected insurance premiums for the year July 1, 2014 through June 30, 2015 and, in some instances, November 1, 2014 through October 31, 2015. These premiums are

1 clearly well in excess of what Columbia can reasonably expect to incur during the
2 rate year ended June 30, 2014.

3 Second, the use of an escalation rate of five percent is not supported by
4 experience. The actual overall insurance premiums for the year ending June 30, 2013
5 (and, for some policies, the year ending October 31, 2013) that Columbia has utilized
6 as its starting point are less than the overall premiums for the 12 months ended May
7 31, 2012. Moreover, insurance premiums have declined each year since the 12
8 months ended May 31, 2010. Finally, the premiums for the 12 months ended June
9 30, 2013 are less than the premiums for the 12 months ended May 31, 2008. Hence,
10 there has been no upward trend in insurance premiums for Columbia.

11 Finally, it is inconsistent to single out one item such as insurance to escalate at
12 a rate greater than inflation and then apply an inflation factor to other expenses not
13 separately identified, as Columbia has done. The GDP Deflator that Columbia has
14 used to escalate most HTY O&M expenses other than labor, benefits and corporate
15 insurance from HTY to FFRY levels is a measure of the overall rate of inflation for
16 all goods and services that make up the GDP or Gross Domestic Product. Therefore,
17 if an escalation factor is applied to corporate insurance, the appropriate escalation
18 factor is the same overall rate of inflation applied to other costs, not at a separate,
19 higher rate.

20 Q. HOW HAVE YOU DETERMINED THE APPROPRIATE ALLOWANCE
21 FOR CORPORATE INSURANCE EXPENSE IN THE RATE YEAR?

22 A. Because Columbia's premiums in effect as of May 31, 2012 already reflect premiums
23 for the 12 months ended June 30, 2013 or later, I have applied an escalation factor of
24 1.56 percent based on the GDP Deflator to project the premiums that will be in effect
25 during the rate year ended June 30, 2014. My calculation of these premiums is

1 presented on Schedule TSC-12. As shown there, I have calculated rate year
2 premiums to be \$2,773,483, which is \$246,074 less than Columbia's rate year claim
3 based on the premiums that will be in effect in the year following the rate year. I
4 would note that in calculating the Workers Compensation premiums transferred to
5 capital, I have reflected my updated labor expense ratio discussed earlier in my
6 testimony.

7
8 **Deferred NiFit Costs**

9 Q. PLEASE EXPLAIN COLUMBIA'S REQUEST FOR RECOVERY OF
10 DEFERRED NIFIT COSTS.

11 A. NiSource is currently in the process of implementing the NiFit project, which is
12 designed to upgrade the financial processes and information system for all NiSource
13 companies, including Columbia. Columbia has proposed to defer the O&M expense
14 associated with the installation of the NiFit project and recover those costs over two
15 years.

16 Q. WHAT IS YOUR RECOMMENDATION?

17 A. Because the majority of the NiFit O&M costs will be incurred in the rate year and,
18 hence, are current costs, I am prepared to accept Columbia's proposal to defer and
19 amortize the costs. However, given the magnitude of the costs (\$2.02 million) and
20 the fact that such costs are not expected to be incurred again in the near term (the life
21 of the NiFit project is expected to be 10 years), I believe that an amortization period
22 of two years is too short. It is my recommendation that the costs be amortized over
23 four years instead of two. As shown on Schedule TSC-13, this adjustment reduces
24 rate year expense by \$505,000.

GEAC costs

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO GEAC SOFTWARE COSTS.

A. Columbia's existing financial software, the GEAC package, is being replaced by the NiFit system during the rate year. Therefore, I am proposing to eliminate the GEAC support and maintenance costs that are included in NCSC billings. As shown on Schedule TSC-14, GEAC support and maintenance costs were \$45,359 in the HTY. After recognizing the increases that were included on Exhibit No. 104, Schedule 2, pages 22 and 27 to account for inflation, excluding these costs reduces rate year expenses by \$46,919.

Longwall Mining Amortization Expense

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO COLUMBIA'S FILED CLAIM FOR LONGWALL MINING AMORTIZATION EXPENSE?

A. Columbia's HTY expenses include \$54,210 for the amortization of Longwall Mining costs that began in October 2008. These costs were inadvertently included in the expense base that was subject to inflation so that the amount included in the Company's FFRY expenses is \$56,074. As of the beginning of the rate year on July 1, 2013, the remaining balance of unamortized Longwall Mining costs will be \$13,552, and this balance will be fully amortized by October 2013. Accordingly, I have reduced Columbia's claimed expense to \$13,552 to reflect the amortization expense that will be recorded in the rate year. As shown on Schedule TSC-15, the adjustment reduces rate year expense by \$42,522.

Lease Expense

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO LEASE EXPENSE?

A. In response to I&E-RE-96-D, Columbia indicated that its claimed expense for rents needed to be corrected and as a result, the expense should be reduced by \$67,625. I have included this adjustment on Schedule TSC-3.

Distribution Integrity Management Program

Q. PLEASE SUMMARIZE COLUMBIA'S CLAIM FOR DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM COSTS.

A. As discussed in detail in the Direct Testimony of Columbia witness Robert M. Kitchell, Columbia is implementing a new Distribution Integrity Management Program (DIMP) consisting of incremental O&M costs associated with increased capital projects and distribution system integrity initiatives begun in 2012. Columbia has attributed the incremental O&M needs to the following items.

- Right-of-way (ROW) clearing
- Atmosphere corrosion reduction
- Maintenance of exposed cathodically protected steel pipe
- Reducing the backlog of open Type 2 leaks
- Cross-bore investigations
- Maximum allowable operating pressure (MAOP) verification
- Increased public awareness plan (RP 1162) spending
- Storage training and staffing
- New operations center
- Enhanced GPS Mapping

The total annual cost of these new programs is \$9.25 million. This includes \$350,000 for the lease of the Alpine Point Operating Center, \$250,000 for labor and benefits for new GPS mapping technicians, \$1,080,000 for internal labor and \$7,570,000 for incremental DIMP O&M costs.

1 Q. HOW DO THE INCREMENTAL DIMP O&M COSTS COMPARE TO
2 HISTORICAL COSTS FOR SIMILAR PROGRAMS?

3 A. Table 2 below provides a comparison of the proposed DIMP program incremental
4 O&M expense with the historical costs for the various programs that are included in
5 DIMP.

6

Table B			
Comparison of Historical Expenditures and Proposed DIMP Incremental Expenditures ⁽¹⁾			
	12 Months Ending <u>5/31/2011</u>	12 Months Ending <u>5/31/2012</u>	DIMP Incremental <u>O&M</u>
Right-of-Way Clearing	\$ 856,171	\$ 695,335	\$ 900,000
Atmospheric Corrosion Remediation	328,680	42,742	900,000
Exposed Coated, CP Mains Maintenance ⁽²⁾	N/A	N/A	1,350,000
Repair of Type-2 leaks ⁽³⁾	5,335,470	5,091,070	2,000,000
Sewer Line Cross-Bore Remediation ⁽²⁾	N/A	N/A	900,000
MAOP Documentation ⁽²⁾	N/A	N/A	1,170,000
RP1162 Expenditures	131,942	73,522	200,000
Storage O&M Training	N/A	N/A	<u>150,000</u>
			7,570,000
<u>Notes:</u>			
(1) All amounts exclude internal labor.			
(2) N/A indicates costs not separately tracked.			
(3) Amounts are for all mains. Type 2 leaks not separately tracked			

7 Because the costs of several of the elements of DIMP have historically not been
8 separately tracked, it is not possible to provide a comparison of total costs. However,
9 as indicated in Table 2, where historical data is available to compare, the incremental

1 DIMP O&M costs reflect a significant increase over historical costs for the various
2 items that comprise Columbia's DIMP.

3 Q. WHAT IS YOUR RECOMMENDATION?

4 A. I have two recommendations with regard to Columbia's Distribution Integrity
5 Management Program. First, the program must be fully coordinated with Columbia's
6 Long-Term Infrastructure Improvement Program that was filed with the Commission
7 on December 7, 2012. Second, Columbia needs to track the incremental annual
8 amounts spent on each specific DIMP program and the extent to which the specific
9 goals of each DIMP program are met. In this way, all parties will have the
10 opportunity to review the costs incurred and the accomplishments of DIMP in
11 Columbia's next base rate case and evaluate the appropriate ongoing spending levels
12 at that time.

13
14 **Depreciation Expense**

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

17 A. Columbia has based rate year depreciation expense on the projected balance of plant
18 in service as of the end of the rate year on June 30, 2014 **plus** projected construction
19 work in progress (CWIP) as of June 30, 2014 of \$16,635,708. Depreciation was
20 calculated on CWIP even though Columbia appropriately did not include CWIP in its
21 FFRY rate base claim.

22 Q. DO YOU AGREE WITH COLUMBIA'S CLAIM BASED ON THE JUNE
23 30, 2014 END OF RATE YEAR PLANT IN SERVICE PLUS CWIP AS OF
24 THAT DATE?

1 A. No. By basing depreciation on the balance of plant in service and CWIP as of the end
2 of the rate year, Columbia has reflected a level of depreciation expense that will not
3 begin to be incurred until after July 1, 2014 instead of the depreciation expense that
4 will be incurred during the rate year ending June 30, 2014. Prior to this case, when
5 Columbia used a future test year that ended before rates went into effect, the use of
6 end of FTY plant to calculate depreciation expense was appropriate in order to reflect
7 the depreciation expense at the time rates went into effect. However, in this case,
8 where Columbia is now allowed to utilize a fully projected future test year or rate
9 year, the use of end of rate year plant and CWIP to calculate depreciation expense is
10 no longer appropriate because doing so significantly overstates the depreciation
11 expense that will be incurred during the rate year. This is turn would allow Columbia
12 to earn is excess of its allowed rate of return.

13 Q. HOW ARE YOU PROPOSING TO DETERMINE DEPRECIATION
14 EXPENSE?

15 A. In order to reflect the level of depreciation expense that will be incurred during the
16 rate year, I have calculated depreciation expense based on the 13-month average
17 balance of plant in service. I have based this calculation on the composite
18 depreciation rate based on the depreciation rates for the various plant accounts
19 proposed by Columbia in this case. As shown on Schedule TSC-16, my adjustment
20 to reflect the depreciation expense that will be incurred during the rate year ending
21 June 30, 2014 reduces depreciation expense by \$2,098,196.

22 I would note that I have included the Company's claimed level of
23 amortization expense as of June 30, 2014. Because amortization expense is based on
24 individual asset amortization, it cannot be calculated using a composite rate. In

1 addition, even though the individual amortizable assets change, there is only a small
2 difference between amortization expense as of July 1, 2013 and June 30, 2014.

3 Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARD TO YOUR
4 ADJUSTMENT TO DEPRECIATION EXPENSE?

5 A. Yes. My review of the deferred tax calculations as presented in Exhibit No. 107
6 indicated that the excess of tax over depreciation expense and the increase in the
7 balance of ADIT during the rate year are based on projected excess of tax over book
8 depreciation during the rate year rather than annualized levels as of the end of the rate
9 year on June 30, 2014. Therefore, I have not made an adjustment to deferred tax
10 expense or the balance of ADIT in conjunction with my adjustment to depreciation
11 expense.

12
13 **FICA Taxes**

14 Q. WHAT ADJUSTMENT HAVE YOU MADE TO PAYROLL TAXES?

15 A. I have adjusted FICA taxes to reflect the adjustments that I have made to labor
16 expense charged to O&M for existing and new Columbia employees. As shown on
17 Schedule TSC-17, recognizing these changes in payroll subject to payroll taxes
18 reduces FICA taxes by \$77,036.

19
20 **Interest Synchronization**

21 Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION
22 ADJUSTMENT.

23 A. To determine the tax deductible interest for ratemaking, I have multiplied the
24 OCA's recommended rate base by the weighted cost of debt included in the capital
25 structure recommended by OCA witness Kahal. This procedure synchronizes the

1 interest deduction for tax purposes with the interest component of the return on rate
2 base to be recovered from ratepayers. As shown at the bottom of Schedule TSC-4,
3 this adjustment reduces the interest deduction by \$1,962,055 compared to the
4 interest deduction recognized by Columbia. This increases state and federal income
5 taxes by \$196,009 and \$618,116, respectively.

6
7 **Income Tax Calculation**

8 Q. HAVE YOU PREPARED A SUMMARY SHOWING THE
9 DETERMINATION OF STATE AND FEDERAL INCOME TAXES?

10 A. Yes. TSC-4 presents a proof of current taxes. I have followed the same format
11 utilized by the Company, beginning with operating income before taxes and
12 adjusting for the additions and deductions necessary to arrive at taxable income. As
13 shown on Schedule TSC-4, I have started with the Company's tax calculation and
14 identified the effects of the adjustments that I have recommended to arrive at the
15 income tax expense consistent with income at present and proposed rates.

16 In preparing this schedule, I have also made one correction to Columbia's
17 calculations of income taxes at proposed rates. In the state income tax calculations
18 presented on Exhibit No. 107, page 17, Company witness Fischer recognized that
19 Columbia is allowed to include an operating loss deduction of 20 percent of state
20 taxable income in calculating current state income taxes, but then included an
21 offsetting increase in state deferred income taxes. Consistent with the practice of
22 flowing through the benefit of state income tax deductions, I have recognized the
23 operating loss deduction in calculating current state income taxes and have
24 eliminated the offset for deferred state income taxes. I would note that Ms. Fischer
25 indicates on page 5 of her Direct Testimony that the Company's claimed tax benefit

1 takes the loss deduction into account, so the inclusion of the offset for deferred
2 taxes appears to be inadvertent. In addition, I would also point out the procedure
3 that I have followed was also reflected by Columbia in its last rate case.

4 Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

5 A. Yes, it does.
6

164357

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

)
)
) Docket Nos. R-2012-2321748
) M-2012-2323645
)

APPENDIX A TO THE
DIRECT TESTIMONY
OF
THOMAS S. CATLIN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 4, 2013

EXETER

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

Prior Expert Testimony

of Thomas S. Catlin

Before State and Federal Commissions:

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket 1513), February 1981. Testified on revenue requirements, cost of service and rate design on behalf of the Providence Water Supply Board.

Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket RID 1819), April & May 1982. Testified on cost analyses and rate design on behalf of the Office of Consumer Advocate.

Washington Gas Light Company (Maryland Public Service Commission, Case No. 7649), October 1982. Testified on cost of service issues on behalf of the Maryland People's Counsel.

Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket R-832316), August 1983. Testified on cost analyses and rate design on behalf of the Office of Consumer Advocate.

Chesapeake & Potomac Telephone Company (D.C. Public Service Commission, Formal Case No. 798), October 1983. Testified on cost of service on behalf of the Public Service Commission Staff.

Columbia Gas of Pennsylvania (Pennsylvania Public Utility Commission, Docket R-832493), April 1984. Testified on revenue, expense, and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Generic Investigation Concerning Intrastate Access Charges (Pennsylvania Public Utility Commission, Docket P-830452), August 1984. Testified on telephone access service costs and subscriber access charge issues on behalf of the Pennsylvania Office of Consumer Advocate.

Gulf Power Company (Florida Public Service Commission, Docket 840086-EI), August 1984. Testified on rate base issues on behalf of the Federal Executive Agencies.

Western Pennsylvania Water Company (Pennsylvania Public Utility Commission, Docket R-842621, et al.), August 1984. Testified on revenue, expense, rate base, and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

ALLTEL Pennsylvania (Pennsylvania Public Utility Commission, Docket R-842710), January 1985. Testified on revenue, expense, rate base and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Chesapeake & Potomac Telephone Company (D.C. Public Service Commission, Formal Case No. 827), March 1985. Testified on cost of service matters on behalf of the Office of People's Counsel.

Chesapeake & Potomac Telephone Company (Maryland Public Service Commission, Case No. 7851), March 1985. Testified on cost of service matters on behalf of the Public Service Commission Staff.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-842632), March 1985. Testified on rate base, expense and income tax issues on behalf of the Office of Consumer Advocate.

New England Telephone and Telegraph Company (Rhode Island Public Utilities Commission, Consolidated Docket 1560(R), 1631, 1654), April 1985. Testified on category cost of service and service cost matters on behalf of the Division of Public Utilities and Carriers.

Chesapeake & Potomac Telephone Company (West Virginia Public Service Commission, Case No. 84-747-T-42T), June 1985. Testified on rate base and expense issues, impacts of divestiture, and separations issues on behalf of the Public Service Commission, Consumer Advocate Division.

Oklahoma Gas & Electric Company (Oklahoma Corporation Commission, Cause No. 29450), July 1985. Testified on rate base, operating income and income tax issues on behalf of the Attorney General.

Bristol County Water Company (Rhode Island Public Utilities Commission, Docket No. 1811), August 1985. Testified on rate base, operating income and income tax issues on behalf of the Division of Public Utilities and Carriers.

Continental Telephone Company of Pennsylvania and Quaker State Telephone Company (Pennsylvania Public Utility Commission, Docket Nos. R-850044 and R-850045, Consolidated hearings), September 1985. Testified on rate base, toll revenue, expense and income tax matters on behalf of the Office of Consumer Advocate.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-850174), November 1985. Testified on rate base, revenue, expense and income tax issues on behalf of the Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-850220), January 1986. Testified on rate base and net operating income issues on behalf of the Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-860296), March 1986. Testified regarding purchased gas costs and cost recovery on behalf of the Office of Consumer Advocate.

Idaho Power Company (Idaho Public Utilities Commission, Case No. U-1006-265), April 1986. Testified on rate base, operating expense, and income tax matters on behalf of the Federal Executive Agencies.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-850287), July 1986. Testified regarding rate base, revenue, expense, and income tax issues on behalf of the Office of Consumer Advocate.

Dauphin Consolidated Water Supply Company (Pennsylvania Public Utility Commission, Docket No. R-860350), July 7, 1986. Testified in rate base, operating revenue and expense, and income tax issues on behalf of the Office of Consumer Advocate.

Blackstone Valley Electric Company (Rhode Island Public Utilities Commission, Docket No. 1849), August 1986. Testified on rate base, revenue, expense and income tax issues on behalf of the Division of Public Utilities and Carriers.

Dayton Power and Light Company (Public Utilities Commission of Ohio, Case No. 86-17-GA-GCR), August 1986. Testified regarding audit of management and performance of gas purchasing policies and practices on behalf of the Public Utilities Commission of Ohio.

West Virginia Water Company (West Virginia Public Service Commission, Case No. 86-212-W-42T), October 1986. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division. (Case settled prior to cross-examination.)

Kentucky West Virginia Gas Company (Federal Energy Regulatory Commission, Docket No. RP86-52-000), November 1986. Testified on elimination of the minimum bill and take or pay exposure on behalf of the Pennsylvania Office of Consumer Advocate.

Huntington Water Corporation (West Virginia Public Service Commission, Case No. 86-341-W-42T), December 1986. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division. (Case settled prior to cross-examination.)

Louisiana Power and Light Company (Louisiana Public Service Commission, Docket No. 16945), December 1986. Testified on rate base, revenue, expense, income tax and phase-in issues on behalf of the Staff of the Commission.

Prior Expert Testimony

of Thomas S. Catlin

Mountain States Telephone and Telegraph Company (Colorado Public Utilities Commission, Docket No. 1720), December 1986. Testified on the measurement of dial tone or access line costs and separations procedures on behalf of the Colorado Office of Consumer Counsel.

Columbia Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP86-168-000), April 1987. Testified on rate base, operating income, and income taxes on behalf of the Commonwealth of Pennsylvania Office of Consumer Advocate.

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP87-7-000), May 1987. Testified on appropriate regulatory treatment of surplus proceeds resulting from termination of pension plan on behalf of the Pennsylvania Office of Consumer Advocate.

Monongahela Power Company (West Virginia Public Service Commission, Case No. 86-524-E-SC), May 1987. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division.

Atlantic City Sewerage Company (New Jersey Board of Public Utilities, Docket No. WO 8606654), June and August 1987. Presented testimony on behalf of Resorts International, Inc., addressing responsibility of Company to pay cost of extending facilities.

Newport Electric Corporation (Rhode Island Public Utilities Commission, Docket No. 1872), July 1987. Testified on rate base and operating income issues, including the effects of the Tax Reform Act of 1986 on behalf of the Division of Public Utilities and Carriers.

General Telephone of the South (West Virginia Public Service Commission, Case No. 86-870-T-42T), July 1987. Testified on rate base, operating income and jurisdictional separations issues on behalf of the Consumer Advocate Division of the Public Service Commission. (Case settled prior to cross-examination.)

Philadelphia Electric Company-Gas Operations (Pennsylvania Public Utility Commission, Docket No. R-870629), August 1987. Testified on operating income and income tax matters on behalf of the Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-850220 Reconsideration), August 1987. Testified on issue of retroactive ratemaking and revenue requirement effects of alternative excess capacity adjustments recommended by others on behalf of Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Dauphin Consolidated Water Supply Company (Pennsylvania Public Utility Commission, Docket No. R-860350 Reconsideration), September 1987. Testified on recognition of proper balance of deferred income taxes collected from ratepayers on behalf of Pennsylvania Office of Consumer Advocate.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio Case No. 87-29-GA-GCR), October 1987. 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 and accepted without cross-examination.)

GTE North, Inc. (Pennsylvania Public Utility Commission, Docket No. M-860105, F. 18), November 1987. Testified on effects of Tax Reform Act of 1986 on behalf of Pennsylvania Office of Consumer Advocate.

Panhandle Eastern Pipe Line Company (Federal Energy Regulatory Commission, Docket No. RP87-103-000), February 1988. Testified on rate base, operating income and income tax issues on behalf of Indiana Office of Utility Consumer Counselor.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-870840), February 1988. Testified on revenue, expense, income tax, and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company-Water Department (Nevada Public Service Commission, Docket No. 87-1226), April 1988. Testified on cost of service allocation on behalf of the Nevada Office of Consumer Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. FA86-19-001), April 1988. Testified regarding cost of service tariff (formula rate) issues on behalf of the Louisiana Public Service Commission.

The Peoples Natural Gas Company (Pennsylvania Public Utilities Commission Docket No. R-880961), August 1988. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

South Central Bell Telephone Company (Kentucky Case No. 10105), August 1988. Testified with regard to South Central Bell's proposed incentive regulation plan on behalf of the Attorney General of the Commonwealth of Kentucky.

Louisiana Power and Light Company (Louisiana Public Service Commission Docket No. U-17906), September 1988. Testified on operating income and rate making policy issues on behalf of the Staff of the Commission.

Prior Expert Testimony

of Thomas S. Catlin

National Gas and Oil Corporation (Public Utilities Commission of Ohio Case No. 88-22-GA-GCR), September 1988. 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).

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 88-24-GA-GCR), October 1988. 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).

Providence Gas Company (Rhode Island Public Utilities Commission Docket No. 1914), December 1988. Testified on operating income and regulatory policy issues on behalf of the Division of Public Utilities and Carriers.

Kentucky-West Virginia Gas Company (Federal Energy Regulatory Commission Docket No. RP86-52-000), February 1989. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-881125), March 1989. Testified on purchased gas costs and take-or-pay cost recovery on behalf of the Pennsylvania Office of Consumer Advocate.

Chesapeake Utilities Corporation (Maryland Public Service Commission Case No. 8154), April 1989. Testified on take-or-pay cost recovery on behalf of Maryland People's Counsel.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission Docket No. R-891208), May 1989. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-891232), May 1989. Testified on purchased gas costs and take-or-pay cost recovery on behalf of the Pennsylvania Office of Consumer Advocate.

Maryland Natural Gas and Frederick Gas Company, Inc. (Maryland Public Service Commission Case Nos. 8153 and 8155), May 1989. Testified on take-or-pay cost recovery on behalf of Maryland People's Counsel.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-891218), July 1989. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

The River Gas Company (Public Utilities Commission of Ohio Case No. 89-31-GA-GCR), August 1989. 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.)

Central Maine Power Company (Maine Public Utilities Commission Docket No. 89-68), August 1989. Testified on revenue, expense, rate base and income tax issues, as well as selection of proper test year on behalf of the Maine Public Advocate.

Public Service of Indiana, Inc. (Indiana Utility Regulatory Commission Cause No. 37414-S2), October 1989. Testified on rate base, net operating income, and accounting issues on behalf of the Indiana Utility Consumer Counselor.

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission Docket No. RP89-49-000), December 1989 and February 1990. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission), February 1990. Testified on one-eighth formula working capital requirement on behalf of the Louisiana Public Service Commission.

Bangor Hydro-Electric Company (Maine Public Utilities Commission Docket No. 90-001), June 1990. Testified on rate base revenues, expenses, sales forecasts and attrition on behalf of the Maine Public Advocate.

Mountain Fuel Supply Company (Utah Public Service Commission Docket No. 89-057-15), July 1990. Co-sponsored testimony regarding natural gas procurement practices and policies.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-901670), July 1990. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company Water Department (Nevada Public Service Commission Docket No. 90-524), September 1990. Testified on class cost of service issues on behalf of the Nevada Office of Consumer Advocate.

Central Maine Power Company (Maine Public Utilities Commission Docket No 90-076), September 1990. Testified on test year rate base, revenue and expense issues and on attrition on behalf of the Maine Public Advocate.

South Central Bell Telephone Company (Louisiana Public Service Commission Docket No. U-17949), October 1990. Testified on operating income issues and attrition on behalf of the Louisiana Public Service Commission.

Prior Expert Testimony
of Thomas S. Catlin

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. ER89-678-000), November 1990. Testified on decommissioning funding issues on behalf of the Louisiana Public Service Commission.

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 91-16-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).

South Central Bell vs. Louisiana Public Service Commission (Nineteenth Judicial District Court, Parish of East Baton Rouge, Louisiana, Docket No. 333, 273), November 1990. Testified on overearnings of South Central Bell on behalf of the Louisiana Public Service Commission.

New Jersey Natural Gas Company (New Jersey Board of Public Utilities Docket No. GR90080786J), January 1991. Testified on cash working capital and storage inventory on behalf of the New Jersey Public Advocate.

Nevada Power Company (Nevada Public Service Commission Docket No. 90-1037), February 1991. Testified on deferred fuel cost and accounting issues on behalf of the U.S. Department of Energy.

City of Great Falls Wastewater Utility (Montana Public Service Commission Docket No. 90.10.66), March 1991. Testified on cost allocation issues 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. Testified on cost allocation issues on behalf of the U.S. Air Force.

Duquesne Light Company, Metropolitan Edison Company and Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket Nos. P-900485, P-910502 and G-900240), May 1991. Testified on behalf of the Pennsylvania Office of Consumer Advocate regarding accounting and regulatory issues in regard to the reactivation of a generating station and the transfer/sale of assets.

Bangor Hydro Electric Company (Maine Public Utilities Commission Docket No. 91-010), June 1991. Testified on test year revenue, expense and rate base and attrition issues on behalf of the Maine Public Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. FA89-28-000), June 1991. Testified regarding proper accounting for fees associated with the sales of accounts receivable on behalf of the Louisiana Public Service Commission.

Prior Expert Testimony

of Thomas S. Catlin

Wakefield Water Company (Rhode Island Public Utilities Commission Docket No. 2006), July 1991. Testified regarding revenue requirements, cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

UGI Corporation (Pennsylvania Public Utility Commission Docket No. R-911973), July 1991. Testified on purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Nevada Power Company (Nevada Public Service Commission Docket No. 91-5055), September 1991. Testified on rate base and net income issues on behalf of U.S. Department of Energy.

Arkansas Louisiana Gas Company (Louisiana Public Service Commission Docket No. U-19236), October 1991. Testified on rate adjustment mechanisms, private line replacement, rate design and postretirement benefits on behalf of the Staff of the Commission.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio, Case No. 91-16-GA-GCR), October 1991. Co-authored report on the audit of management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

Sierra Pacific Power Company (Nevada Public Service Commission, Docket Nos. 91-7079, 91-7080 and 91-7081), November 1991. Testified on consolidated income taxes and construction work in progress on behalf of the Nevada Office of Consumer Advocate.

Sierra Pacific Power Company (Nevada Public Service Commission, Docket No. 91-7081), December 1991. Testified on water cost allocation and rate design issues on behalf of the Nevada Office of Consumer Advocate.

Louisiana Gas Service Company (Louisiana Public Service Commission, Docket No. U-19237), December 1991. Testified on test year net income, rate base and attrition issues on behalf of the Staff of the Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 2022), January 1992. Testified on matters pertaining to a proposed surcharge on behalf of the Division of Public Utilities and Carriers.

South Jersey Gas Company (New Jersey Board of Regulatory Commissioners, Docket No. GR91071243J), January and February 1992. Testified on rate base, operating income, and income tax issues on behalf of New Jersey Rate Counsel.

Prior Expert Testimony

of Thomas S. Catlin

Newport Water Division (Rhode Island Public Utilities Commission, Docket No. 2029), February 1992. Testified on cost allocation and rate design matters on behalf of the Division of Public Utilities and Carriers.

Equitable Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00912164), April 1992. Testified on rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Mountain Fuel Supply Company (Utah Public Service Commission, Docket Nos. 91-057-11 & 15), May 1992. Testified on gas procurement and gas cost issues on behalf of the Utah Committee of Consumer Services.

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19631) June 1992. Testified on rate adjustment mechanisms, rate design and postretirement benefits on behalf of the Staff of the Commission.

Artesian Water Company, Inc. (Delaware Public Service Commission, Docket No. 92-5), June 1992. Testified on cost allocation and rate design issues on behalf of the Staff of the Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 2048), August 1992. Testified on revenue requirements, cost allocation policy and rate design issues on behalf of the Division of Public Utilities and Carriers.

US West Communications, Inc. (Utah Public Service Commission, Docket No. 92-049-05), August and October 1992. Testified on proper ratemaking treatment of postretirement benefits expense on behalf of Utah Committee of Consumer Services.

Dallas Water Company et al. (Pennsylvania Public Utility Commission, Docket No. R-00922326 et al.), September 1992. Testified on revenue requirements and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Generic Investigation into Treatment of Postretirement Benefits Expense (Utah Public Service Commission, Docket No. 92-999-04), October 1992. Testified on proper ratemaking treatment of postretirement benefits expense on behalf of Utah Committee of Consumer Services.

Commonwealth Gas Services, Inc. (Virginia Corporation Commission, Case No. PUE920037), October 1992. Testified on revenue, cash working capital, weather normalization and post in service carrying charges on behalf of the Division of Consumer Counsel of the Office of Attorney General.

Prior Expert Testimony

of Thomas S. Catlin

Entergy Corporation and Gulf States Utilities (Louisiana Public Service Commission, Docket No. U-19904), November 1992. Testified on merger related issues on behalf of the Louisiana Public Service Commission Staff.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-00922378), December 1992. Testified 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. Coauthored report on the audit of management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

Bossier Rural Electric Membership Cooperative (Louisiana Public Service Commission, Docket No. U-19944), February 1993. Testified on prudence standards applicable to utility decision making on behalf of the Staff of the Commission.

Consideration of Statement of Financial Accounting Standard No. 106 (Louisiana Public Service Commission, Docket No. U-20181), February 1993. Testified on regulatory issues related to adoption of SFAS No. 106 for ratemaking on behalf of the Staff of the Commission.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00922476), March 1993. Testified on rate base and net income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company Water Department (Nevada Public Service Commission, Docket No. 92-121022), April 1993. Testified on class cost of service and rate design on behalf of the Nevada Office of Consumer Advocate. (Case settled prior to cross examination.)

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 92-345), May 1993. Testified on test year net income and rate base and attrition issues on behalf of the Staff of the Maine PUC.

Dauphin Consolidated Water Supply Company and General Waterworks of Pennsylvania, Inc. (Pennsylvania Public Utility Commission, Docket No. R-00932604), June 1993. Testified on rate base, income tax and class cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Kent County Water Authority (Rhode Island Public Utilities Commission, Docket No. 2098), July 1993. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Prior Expert Testimony

of Thomas S. Catlin

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission, Docket No. RP92-73-000), July 1993. Testified on rate base and revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

City of Woonsocket Water Department (Rhode Island Public Utilities Commission, Docket No. 2099), July 1993. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-00932548), July 1993. Testified on income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Conestoga Telephone & Telegraph Company (Pennsylvania Public Utility Commission Docket No. I-00920015), September 1993. Testified on revenue expense and rate base issues as well as proper average schedule separations procedures on behalf of the Pennsylvania Office of Consumer Advocate.

The Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 93-14-GA-GCR), October 1993. Co-authored report on the audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

The Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. P-00930715), December 1993. Testified on historical and projected earnings levels and earnings monitoring in conjunction with alternative regulatory plan on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00932670), February 1994. Testified on class cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00932868), April 1994. Testified on class cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Southwest Gas Corporation - Southern Arizona Division (Arizona Corporation Commission, Docket No. U-1551-93-272), May 1994. Testified on revenue and rate base issues on behalf of the Staff of the Arizona Corporation Commission. (Case settled prior to cross-examination)

Prior Expert Testimony

of Thomas S. Catlin

Commonwealth Edison Company (Illinois Commerce Commission, Docket No. 94-0065), June 1994. Testified on nuclear decommissioning funding on behalf of the U.S. Department of Energy.

West Penn Power Company (Pennsylvania Public Utility Commission Docket R-00942986), July 1994. Testified on net income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

City of Bethlehem-Bureau of Water (Pennsylvania Public Utility Commission, Docket No. R-00943124), October 1994. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

General Waterworks of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00943152), October 1994. Testified on cost allocation and rate design issues 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 the audit of the management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without hearings.)

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19997), November 1994. Testified on the costs properly included in the weighted average cost of gas of Louisiana Intrastate Gas Corporation and the purchased gas adjustment of Trans La on behalf of Staff of the Commission.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket Nos. RP91-203-000 and RP92-132-000, Phase II-PCB Issues), December 1993. Testified on cost of PCB remediation in current dollars and percentage allowance applicable to claimed PCB costs on behalf of the Pennsylvania Office of Consumer Advocate and the Ohio Office of the Consumer's Counsel. (Case settled prior to cross-examination.)

New England Telephone and Telegraph Company (Maine Public Utilities Commission, Docket Nos. 94-123 and 94-254), December 1994. Testified on Process Re-engineering (downsizing) costs and benefits and on attrition issues on behalf of the Maine Public Advocate.

Louisiana Power & Light Company (Louisiana Public Service Commission, Docket No. U-20925), February 1995. Testified on rate base and operating income on behalf of the Staff of the Public Service Commission.

Prior Expert Testimony

of Thomas S. Catlin

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00943231), February 1995. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

NorAm Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP93-343-000), March 1995. Testified on rate base, operating expense and income tax issues on behalf of the Arkansas Public Service Commission and the Louisiana Public Service Commission. (Case settled prior to hearings.)

Artesian Water Company, Inc. (Delaware Public Service Commission, Docket No. 94-164), March 1995. Testified on cost allocation, rate design and monthly billing issues on behalf of the Staff of the Public Service Commission. (Case settled prior to cross-examination.)

Pennsylvania Power & Light Company (Pennsylvania Public Utility Commission, Docket No. R-00943271), April 1995. Testified on operating income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-953299), June 1995. Testified on revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 2304), July 1995. Testified on water consumption and cost allocation/rate design issues on behalf of the Division of Public Utilities and Carriers.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112-000), September 1995. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP95-197-000), January 1996. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Frontier Communications of Pennsylvania, et al. (Pennsylvania Public Utility Commission, Docket No. P-00951005), May 1996. Testified regarding financial issues and operational aspects of Companies' proposal to implement a streamlined form of regulation (price cap) on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Bell Atlantic-Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00963550), May 1996. Testified on financial issues, revenue growth, and capital expenditures in conjunction with Bell Atlantic-Pennsylvania's proposal to rebalance rates. Testimony filed on behalf of the Pennsylvania Office of Consumer Advocate.

Petition of AT&T Communications of Pennsylvania for Arbitration of its Interconnection Request to Bell Atlantic-PA (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Sponsored position of Pennsylvania Office of Consumer Advocate on resale discount, 900 number call billing, network interface devices, and unbundled loop rates in arbitration hearings.

Bell Atlantic-Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00963578), September 1996. Testified regarding the determination of the appropriate resale discount for Bell Atlantic-Pennsylvania on behalf of the Pennsylvania Office of Consumer Advocate.

Pacific Bell Communications, Inc. (Public Utilities Commission of the State of California, Docket No. 96-03-007), October 1996. Testified on affiliate relationship issues under Section 272 of the Telecommunications Act of 1996 on behalf of the California Cable Television Association.

West Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 96-221-GA-GCR), November 1996. Co-authored report on the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Case settled prior to cross-examination.)

Application of MFS Intelenet of Pennsylvania, Inc. et al. (Phase III) (Pennsylvania Public Utility Commission Docket No. A-310203F0002 et al.), January 1997. Testified on loop cost issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission Docket Nos. RP91-203-062 and RP92-132-049), March 1997. Testified on ratemaking treatment of New England laterals on behalf of the Tennessee Rate Design Customer Group.

Frontier Communications of Oswayo River, Inc. (Pennsylvania Public Utility Commission Docket Nos. C-00957322 and C-00957324), May 1997. Testified on EAS rate issues on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-00973953), June 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Transcontinental Gas Pipeline Corporation (Federal Energy Regulatory Commission Docket No. RP97-71-000), June 1997. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination)

Pennsylvania Power & Light Company (Pennsylvania Public Utility Commission Docket No. R-00973954), July 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Metropolitan Edison Company (Pennsylvania Public Utility Commission Docket No. R-00974008), September 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket No. R-00974009), September 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission Docket No. R-00973981), November 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Duquesne Light Company (Pennsylvania Public Utility Commission Docket No. R-00974104), November 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc. (Pennsylvania Public Utility Commission Docket No. R-00973975), November 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Jersey Central Power & Light Company (New Jersey Board of Public Utilities Docket No. E097070459), November 1997. Testified on issues related to the determination of stranded costs including fossil decommissioning costs, income tax related regulatory assets and liabilities and materials and supplies inventories on behalf of the Division of the Ratepayer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925), November 1997. Testified on issues related to the determination of the cost of service under the Company's Formula Rate Plan on behalf of the Louisiana Public Service Commission Staff.

Pennsylvania Power Company (Pennsylvania Public Utility Commission Docket No. R-00974149), January 1998. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes 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 the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Case settled prior to cross-examination.)

Northern Natural Gas Company (Federal Energy Regulatory Commission Docket No. RP98-203-000), October 1998. Testified on rate base and cost of service issues on behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. (Case settled prior to cross-examination.)

ALLTEL Pennsylvania, Inc. (Pennsylvania Public Utility Commission Docket No. P-00981423), December 1998. Testified with regard to ALLTEL's proposed Alternative Form of Regulation and Network Modernization Plan on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania Telephone Association Small Company Group (Pennsylvania Public Utility Commission Docket No. P-00981425 et. al.), December 1998. Testified with regard to the PTA's proposed Alternative and Streamlined Forms of Regulation and Network Modernization Plans on behalf of the Pennsylvania Office of Consumer Advocate.

Columbia Gas of Ohio (Public Utilities Commission of Ohio Case No. 98-223-GA-GCR), January 1999. Co-authored report on the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Case settled prior to cross-examination.)

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925), May 1999. Testified on issues related to the determination of the cost of service related to the Company's 1998 Formula Rate Plan filing on behalf of the Staff of Louisiana Public Service Commission. (Case settled prior to cross-examination.)

United Water Rhode Island, Inc. (Rhode Island Public Utilities Commission Docket No. 2873), June 1999. Testified on revenue requirement and rate design issues in conjunction with a settlement. Testified on behalf of the Division of Public Utilities & Carriers.

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of Thomas S. Catlin

Woonsocket Water Department (Rhode Island Public Utilities Commission Docket No. 2904), July 1999. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Delta Natural Gas Company (Kentucky Public Service Commission Case Nos. 99-046 and 99-176), July 1999. Testified with regard to Delta's proposed alternative regulation plan on behalf of the Attorney General of the Commonwealth of Kentucky.

Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-00994782), September 1999. Testified on recovery of costs associated with natural gas restructuring on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission Docket No. R-00994784), October 1999. Testified on recovery of costs associated with natural gas restructuring on behalf of the Pennsylvania Office of Consumer Advocate.

City of Newport-Water Division (Rhode Island Public Utilities Commission Docket No. 2985), December 1999. Testified regarding revenue requirement and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Distribution Company (Pennsylvania Public Utility Commission Docket No. R-00994785), December 1999. Testified on recovery of costs associated with natural gas restructuring on behalf of the Pennsylvania Office of Consumer Advocate.

UGI Utilities, Inc.-Gas Division (Pennsylvania Public Utility Commission Docket No. R-00994786), December 1999. Testified on recovery of costs associated with natural gas restructuring on behalf of the Pennsylvania Office of Consumer Advocate.

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925, 1999 Formula Rate Plan Proceeding), January 2000. Testified on issues related to the determination of the cost of service and customer satisfaction survey results on behalf of the Staff of the Louisiana Public Service Commission.

T.W. Phillips Gas and Oil Company (Pennsylvania Public Utility Commission Docket No. R-00994790), April 2000. Testified on recovery of costs associated with natural gas restructuring on behalf of the Pennsylvania Office of Consumer Advocate.

PP&L Inc. (Pennsylvania Public Utility Commission Docket No. M-FAC-9908), April 2000. Testified on issues related to the reconciliation of PP&L's competitive transition charge on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Entergy Louisiana, Inc. & Entergy Corporation (Louisiana Public Service Commission Docket No. U-23356), June 2000. Testified on results of investigation into costs included in Entergy Louisiana, Inc.'s fuel adjustment clause and associated purchased gas contracts on behalf of the Staff of the Louisiana Public Service Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3163), October 2000. Testified on sales, revenue and costs of service issues on behalf of the Division of Public Utilities and Carriers.

Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3162), October 2000. Testified on revenues, cost of service and rate design issues on behalf of the Division of Public Utilities and Carriers.

Metropolitan Edison Company and Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket Nos. P-00001837, P-00001838, P-00974008 and P-00974009), November 2000. Testified regarding updated stranded cost claims in conjunction with Companies' petitions for completion of the post-divestiture portion of their restructuring plans on behalf of the Pennsylvania Office of Consumer Advocate.

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3193), March 2001. Testified regarding cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Metropolitan Edison Company and Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket Nos. P-00001860 and P-00001861), March 2001. Testified on issues related to the Companies' request for a rate cap exception pursuant to their restructuring settlements on behalf of the Pennsylvania Office of Consumer Advocate.

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. 20925(SC)), March 2001. Testified regarding regulatory assets recognizable as stranded costs on behalf of the Staff of the Louisiana Public Service Commission.

Citizens Utilities Company and Atmos Energy Corporation (Louisiana Public Service Commission Docket No. S-25003), April 2001. Testified regarding acquisition of Louisiana gas assets of Citizens Utilities by Atmos Energy on behalf of the Staff of the Louisiana Public Service Commission.

Atmos Energy Corporation and Citizen's Utilities Company (Louisiana Public Service Commission Docket No. S-25003), April 2001. Testified regarding the acquisition of Louisiana Gas Service Company and other Louisiana gas assets of Citizen's Utilities by Atmos Energy on behalf of the Commission Staff.

Prior Expert Testimony

of Thomas S. Catlin

Dayton Power & Light Company (Public Utilities Commission of Ohio Case No. 00-220-GA-GCR), May 2001. Co-authored report on the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Case settled prior to cross-examination.)

Philadelphia Water Department (Philadelphia Water Commission 2001 Water and Wastewater Rate Proceeding), June 2001. Testified regarding water cost allocation and rate design on behalf of the Office of Public Advocate.

Community Service Telephone Company (Maine Public Utilities Commission Docket No. 2000-249), July 2001. Testified on revenue requirement issues on behalf of the Maine Office of Public Advocate. (Case settled prior to cross-examination.)

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925, 2000 Formula Rate Plan), August 2001. Testified on stipulated adjustments to the Company's filed cost of service on behalf of the Staff of the Louisiana Public Service Commission.

Southwest Gas Corporation (Public Utilities Commission of Nevada Docket No. 01-7023), November 2001. Testified on revenue requirement issues on behalf of the Office of Attorney General Bureau of Consumer Protection. (Case settled prior to cross-examination.)

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925, 2001 Formula Rate Plan), November 2001. Testified on issues related to the determination of the cost of service under the Company's Formula Rate Plan on behalf of the Staff of the Louisiana Public Service Commission.

Central Maine Power Company (Maine Public Utilities Commission Docket No. 2001-232), November 2001. Testified on issues related to the reconciliation and determination of stranded costs on behalf of the Maine Office of Public Advocate. (Case settled prior to cross-examination.)

Bangor Hydro-Electric Company (Maine Public Utilities Commission Docket No. 2001-239), November 2001. Testified on issues related to the reconciliation and determination of stranded costs on behalf of the Maine Office of Public Advocate. (Case settled prior to cross-examination.)

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission Docket No. RP01-245-000), November 2001. Testified on revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3378), December 2001. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers. (Case settled prior to cross-examination.)

Reliant Energy Arkla and Reliant Energy Entex (Louisiana Public Service Commission Docket No. S-26166), January 2002 and June 2002. Testified regarding corporate reorganization and provisions to protect retail ratepayers on behalf of the Staff of the Commission (Testimony presented live.)

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3409), March 2002. Testified regarding NBC's abbreviated rate increase request and the design of rates on behalf of the Division of Public Utilities and Carriers.

Pike County Power and Light Company, (Pennsylvania Public Utility Commission Docket No. R-00016849 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

PPL Electric Utilities Corporation (Pennsylvania Public Utility Commission Docket No. R-00016850 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

Pennsylvania Power Company (Pennsylvania Public Utility Commission Docket No. R-00016851 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

Metropolitan Edison Company (Pennsylvania Public Utility Commission Docket No. R-00016852 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket No. R-00016853 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

Duquesne Light Company (Pennsylvania Public Utility Commission Docket No. R-00016854 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

UGI Utilities, Inc. - Electric Division (Pennsylvania Public Utility Commission Docket No. R-00016855 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

Prior Expert Testimony

of Thomas S. Catlin

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-00016856 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

West Penn Power Company, (Pennsylvania Public Utility Commission Docket No. R-00016857 C0001), April 2002. Testified regarding Company's request for a rate cap exception to increase rates on behalf of the Pennsylvania Office of Advocate.

Philadelphia Gas Works (Pennsylvania Public Utility Commission Docket No. R-00017034), May 2002. Testified regarding proposed weather normalization adjustment clause on behalf of the Pennsylvania Office of Advocate.

Total Environmental Solutions, Inc. (Louisiana Public Service Commission Docket No. U-22148, Subdocket G), June 2002. Testified regarding proposal to realign nonresidential water and sewer rates on behalf of the Staff of the Louisiana Public Service Commission.

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925, Subdocket B), August 2002. Testified on Term Sheet entered into to resolve case and achieve sharing of mark-to-market tax deduction for the Vidalia purchased power contract. Testified jointly with Matthew Kahal on behalf of the Staff of Louisiana Public Service Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3446), October 2002. Testified on revenue requirements and rate design issues on behalf of the Division of Public Utilities and Carriers.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3432), December 2002. Testified on issues related to stormwater rates on behalf of the Division of Public Utilities and Carriers.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3483), March 2003. Testified on revenue requirements and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Distribution Corporation Pennsylvania Division (Pennsylvania Public Utility Commission Docket No. R-00038168), July 2003. Testified on rate base and operating revenues and expense issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 02-221-GA-GCR), co-authored report on the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio.

Prior Expert Testimony

of Thomas S. Catlin

Total Environmental Solutions, Inc. (Louisiana Public Service Commission Docket No. U-22148, Subdocket H), August 2003. Testified on water and sewer revenue requirements and rate design on behalf of the Staff of Louisiana Public Service Commission. (Case settled prior to cross-examination.)

Pascoag Utility District (Rhode Island Public Utilities Commission Docket No. 3546), November 2003. Testified on revenue and expense issues on behalf of the Division of Public Utilities and Carriers. (Case settled prior to cross-examination.)

Centerpoint Energy Entex, Louisiana Division (Louisiana Public Service Commission Docket No. U-26720, Subdocket A), December 2003. Presented Staff Recommendation report addressing revenue requirements, rate design and alternative regulatory plan on behalf of the Staff of the Louisiana Public Service Commission. (Case settled prior to cross-examination.)

Northern Natural Gas Company (Federal Energy Regulatory Commission Docket No. RP03-398-000), December 2003. Testified on rate base and cost of service issues on behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association.

City of Hagerstown, Maryland (Maryland Public Service Commission Case No. 8934), February 2004. Testified on proper methodology for establishing water and sewer rates for customers outside the City limits on behalf of the Water and Sewer Advisory Commission of Washington County.

City of Newport Utilities Department, Water Division (Rhode Island Public Utilities Commission Docket No. 3578), March 2004. Testified on revenue requirement, cost allocation and rate design issues on behalf of the Division of Public Utilities and carriers.

PPL Electric Utilities Corporation (Pennsylvania Public Utility Commission Docket No. R-000049255), June 2004. Testified on policy and revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3592), June 2004. Testified regarding NBC's abbreviated rate increase request on behalf of the Division of Public Utilities and Carriers.

Centerpoint Energy Arkla, Louisiana Division (Louisiana Public Service Commission Docket No. U-27676), July 2004. Presented Staff Recommendation report addressing revenue requirements, rate design and alternative regulatory plan on behalf of the Staff of the Louisiana Public Service Commission. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

Entergy Louisiana, Inc. (Louisiana Public Service Commission Docket No. U-20925 RRF 2004), August 2004. Testified on policy and revenue requirement issues on behalf of the Staff of the Louisiana Public Commission.

Northern Natural Gas Company (Federal Energy Regulatory Commission Docket No. RP04-155-000), November 2004. Testified on rate base and cost of service issues on behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. (Case settled prior to cross-examination.)

National Fuel Gas Distribution Corporation Pennsylvania Division (Pennsylvania Public Utility Commission Docket No. R-00049656), December 2004. Testified on rate base and operating revenues and expense issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Philadelphia Water Department (Philadelphia Water Commission Docket No. FY 2005-2008 Rates), March 2005. Testified regarding water cost allocation and rate design on behalf of the Office of Public Advocate.

Block Island Power Company (Rhode Island Public Utilities Commission Docket No. 3655), April 2005. Testified on operating income and rate base issues on behalf of the Division of Public Utilities and Carriers.

Entergy Gulf States, Inc.-Louisiana Gas (Louisiana Public Service Commission Docket No. U-28035), May 2005. Presented Staff Recommendation report addressing revenue requirements, rate design and alternative regulatory plan on behalf of the Staff of the Louisiana Public Service Commission. (Case settled prior to cross-examination.)

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3674), July 2005. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

City of Newport Utilities Department, Water Division (Rhode Island Public Utilities Commission Docket 3675), September 2005. Testified on revenue requirements and rate design issues on behalf of the Division of Public Utilities and Carriers.

Verizon New England, Inc. d/b/a Verizon Maine (Maine Public Service Commission Docket No. 2005-155), September 2005. Testified on revenue requirements issues on behalf of the Maine Office of Public Advocate.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3684), October 2005. Testified on revenue requirements and rate design issues on behalf of the Division of Public Utilities and Carriers.

Prior Expert Testimony

of Thomas S. Catlin

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3707), February 2006. Testified on revenue requirement and rate design issues on behalf of the Division of Public Utilities and Carriers.

Cleco Power, LLC (Louisiana Public Service Commission Docket No. U-29157), February 2006. Testified with Matthew I. Kahal regarding Staff's recommendations regarding Phase I recovery of storm damage costs resulting from Hurricanes Katrina and Rita on behalf of the Staff of the Louisiana Public Service Commission.

Atmos Energy Corporation (Louisiana Public Service Commission Consolidated Docket Nos. U-28814 et. al.), May 2006. Presented Staff's recommendation regarding renewal of alternative regulatory plans of Louisiana Gas Services and Trans Louisiana Gas Company of the Staff of the Louisiana Public Service Commission.

Metropolitan Edison Company (Pennsylvania Public Utility Commission Docket No. R-00061366), July 2006. Testified regarding rate base and net operating income issues on behalf of the Pennsylvania Office of Advocate.

Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket No. R-00061367), July 2006. Testified regarding rate base and net operating income issues on behalf of the Pennsylvania Office of Advocate.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3775), October 2006. Testified on revenue requirement and rate design issues on behalf of the Division of Public Utilities and Carriers.

Entergy Louisiana, LLC and Entergy Gulf States, Inc-Louisiana (Louisiana Public Service Commission Docket No. U-29203), January 2007. Testified on issues related to costs eligible for recovery as storm damage costs due to Hurricanes Katrina and Rita on behalf of the Staff of the Louisiana Public Commission.

Southern Indiana Gas and Electric Company (Indiana Utility Regulatory Commission Cause No. 43111), February 2007. Testified on rate base and net operating income issues on behalf of the Indiana Office of Utility Consumer Counselor.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3797), March 2007. Testified on revenue requirement and rate design issues on behalf of the Division of Public Utilities and Carriers.

City of Newport Utilities Department, Water Division (Rhode Island Public Utilities Commission Docket No. 3818), May 2007. Testified on revenue requirement and cost recovery issues on behalf of the Division of Public Utilities and carriers.

Prior Expert Testimony

of Thomas S. Catlin

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 3832), July 2007. Testified on revenue requirements issues on behalf of the Division of Public Utilities and Carriers.

Central Maine Power Company (Maine Public Utility Commission Docket No. 2007-215), August 2007. Testified on merger savings, revenue requirement and alternative rate plan issues on behalf of the Maine Office of Public Advocate.

Central Maine Power Company and Maine Natural Gas Corporation (Maine Public Utilities Commission Docket No. 2007-355), November 2007. Testified regarding non-financial issues and conditions to protect Maine ratepayer interests related to potential acquisition of Central Maine Power and Maine Natural Gas's parent company, Energy East, by IBERDROLA, SA. Testified on behalf of Maine Office of Public Advocate.

Entergy Louisiana, LLC (Louisiana Public Service Commission Docket No. U-30192, Phase II), March 2008. Testified regarding contra-AFUDC accounting and rate recovery issues associated with repowering of the Little Gypsy Unit 3 generating station on behalf of the Staff of the Louisiana Public Service Commission.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 3905), March 2008. Testified on revenue requirements and rate design issues on behalf of the Division of Public Utilities and Carriers.

Entergy Louisiana, LLC and Entergy Gulf States, Inc. – Louisiana (Louisiana Public Service Commission Docket No. U-29203, Phases IV and V), April 2008. Testified regarding benefits of securitization under Louisiana Act 55 on behalf of the Staff of the Louisiana Public Service Commission. (Testimony submitted by Affidavit.)

Entergy Louisiana, LLC (Louisiana Public Service Commission Docket No. U-20925 (FRP-2006)), April 2008. Testified on revenue requirement issues on behalf of the Staff of the Louisiana Public Service Commission.

Kent County Water Authority (Rhode Island Public Utilities Commission Docket No. 3942), July 2008. Testified on revenue requirements, cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Indiana Michigan Power Company (Indiana Utility Regulatory Commission Cause No. 43306), September 2008. Testified on revenue requirements issues on behalf of the Indiana Office of Utility Consumer Counselor. (Case settled prior to cross-examination.)

City of Newport Utilities Department, Water Division (Rhode Island Public Utilities Commission Docket No. 4025), April 2009. Testified on revenue requirement and cost recovery issues on behalf of the Division of Public Utilities and carriers.

Prior Expert Testimony

of Thomas S. Catlin

The Narragansett Bay Commission (Rhode Island Public Utilities Commission Docket No. 4026), April 2009. Testified on cost recovery and rate design issues on behalf of the Division of Public Utilities and Carriers.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission Cause No. 43526), May 2009. Testified on revenue requirement issues on behalf of the Indiana Office of Utility Consumer Counselor.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 4061), July 2009. Testified on revenue requirement and cost recovery issues on behalf of the Division of Public Utilities and Carriers.

Cleco Power, LLC (Louisiana Public Service Commission Docket No. U-30689) September 2009. Testified in support of proposed stipulated settlement on issues related to overall cost of service and new formula rate plan on behalf of the Staff of the Louisiana Public Service Commission.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. M-2009-2123944), October 2009. Testified with regard to smart meter cost recovery issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

PPL Electric Utilities Corporation (Pennsylvania Public Utility Commission Docket No. M-2009-2123945), October 2009. Testified with regard to smart meter cost recovery issues on behalf of the Pennsylvania Office of Consumer Advocate.

Duquesne Light Company (Pennsylvania Public Utility Commission Docket No. M-2009-2123948), October 2009. Testified with regard to smart meter cost recovery issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (Louisiana Public Service Commission Docket No. U-30981), December 2009. Testified on issues related to costs eligible for recovery as storm damage costs due to Hurricanes Gustav and Ike on behalf of the Staff of the Louisiana Public Service Commission.

Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (Louisiana Public Service Commission Docket No. U-30981), March 2010. Testified in support of proposed uncontested stipulated settlement related to the recoverable level of storm costs and the appropriate level of storm reserves on behalf of the Staff of the Louisiana Public Service Commission.

Prior Expert Testimony

of Thomas S. Catlin

Philadelphia Gas Works (Pennsylvania Public Utility Commission Docket No. R-2009-2139884), March 2010. Testified regarding the recovery of accrual basis costs of provided OPEBs pursuant to GASB No. 45 on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Southern Indiana Gas and Electric Company/Vectren South Electric (Indiana Utility Regulatory Commission Cause No. 43839), June 2010. Testified on rate base and net operating income issues on behalf of the Indiana Office of Utility Consumer Counselor.

Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (Louisiana Public Service Commission Docket No. U-31237), July 2010. Testified in support of settlement on nuclear decommissioning funding allowances for the Waterford 3 and River Bend Nuclear Generating Stations on behalf of the Staff of the Louisiana Public Service Commission.

T.W. Phillips Gas and Oil Company (Pennsylvania Public Utility Commission Docket No. R-2010-2167797), August 2010. Testified regarding the rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission Docket No. 4171), September 2010. Testified on revenue requirement and cost recovery issues on behalf of the Division of Public Utilities and Carriers.

West Penn Power Company d/b/a Allegheny Power (Pennsylvania Public Utility Commission Docket No. P-2010-2158084), November 2010. Testified regarding the proposal to implement a Reconcilable Transmission Service Charge on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Peoples Natural Gas Company, LLC (Pennsylvania Public Utility Commission Docket No. R-2010-2201702), January 2011. Testified regarding rate base, net operating income and policy issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Columbia Gas of Pennsylvania, Inc. (Pennsylvania Public Utility Commission Docket No. R-2010-2215623), April 2011. Testified regarding rate base, net operating income and policy issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Northern Utilities, Inc. (Maine Public Utilities Commission Docket No. 2011-92), August 2011. Testified regarding rate base, net operating income and policy issues on behalf of the Maine Public Advocate. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

City of Newport Utilities Department, Water Division (Rhode Island Public Utilities Commission Docket No. 4243), August 2011. Testified on revenue requirement and cost recovery issues on behalf of the Division of Public Utilities and carriers. (Case settled prior to cross-examination.)

United Water Rhode Island, Inc. (Rhode Island Public Utilities Commission Docket No. 4255), September 2011. Testified on revenue requirement issues of behalf of the Division of Public Utilities & Carriers. (Case settled prior to cross-examination.)

Golden State Water Company (California Public Utilities Commission Docket No. A.11-07-17), February 2012. Testified on operating expense and income tax issues on behalf of The Utility Reform Network. (Case settled prior to cross-examination.)

Aqua Pennsylvania, Inc. (Pennsylvania Public Utility Commission Docket No. R-2011-2267958), February 2012. Testified regarding rate base, net operating income and policy issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Peoples Natural Gas Company, LLC (Pennsylvania Public Utility Commission Docket No. R-2012-2285985), May 2012. Testified regarding rate base, net operating income and policy issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Equitable Gas Company, LLC (Pennsylvania Public Utility Commission Docket Nos. R-2012-2312597 and G-2012-2312597), October 2012. Testified regarding ratemaking and policy issues associated with Equitable's proposed acquisition of two gathering systems from its affiliates. (Case settled prior to cross-examination.)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket Nos. R-2012-2321748
	)	M-2012-2323645
Columbia Gas of Pennsylvania, Inc.	)	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY
OF
THOMAS S. CATLIN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 4, 2013

EXETER

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

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Operating Income
Rate Year Ended June 30, 2014

	Company Amounts at Present Rates (1)	OCA Adjustments	Amounts per OCA at Present Rates	Pro Forma Increase	Amounts at Proposed Rates
Operating Revenue					
Base Rate Revenue	\$ 214,993,132		\$ 214,993,132	\$ 43,436,513	\$ 258,429,645
Gas Cost Revenue	150,198,627		150,198,627	-	150,198,627
Rider USP	10,858,071		10,858,071	-	10,858,071
Storage Interest	-		-	-	-
Unbundled Uncollectibles-Gas Costs	1,848,276		1,848,276	-	1,848,276
Late Payment Fees (1)	944,367		944,367	108,548	1,052,915
Other Operating Revenue	464,423		464,423	-	464,423
Total Revenue	\$ 379,306,896	\$ -	\$ 379,306,896	\$ 43,436,513	\$ 422,851,957
Operating Revenue Deductions					
Operation & Maintenance Expense					
Purchased Gas Costs	150,198,627		150,198,627	-	150,198,627
Other	137,753,458	(6,428,746)	131,324,712	633,304	131,958,016
Depreciation Expense	41,961,336	(2,098,196)	39,863,140	-	39,863,140
Taxes Other Than Income	3,688,203	(77,036)	3,611,167	-	3,611,167
Total Operating Revenue Deductions	\$ 333,601,624	\$ (8,603,978)	\$ 324,997,646	\$ 633,304	\$ 325,630,950
Operating Income Before Taxes	\$ 45,705,272	\$ 8,603,978	\$ 54,309,250	\$ 42,803,208	\$ 97,221,006
Income Taxes					
State Income Tax	(796,184)	1,055,547	259,363	3,682,202	3,941,565
Federal Income Tax	5,239,012	3,328,670	8,567,682	13,692,352	22,260,034
Investment Tax Credit	(360,239)	-	(360,239)	-	(360,239)
Total Income Taxes	\$ 4,082,589	\$ 4,384,217	\$ 8,466,806	17,374,554	\$ 25,841,360
Utility Operating Income	\$ 41,622,683	\$ 4,219,761	\$ 45,842,444	25,428,654	\$ 71,379,646
Rate Base	\$ 1,011,680,660	(60,130,616)	\$ 951,550,044		\$ 951,550,044
Rate of Return	4.11%		4.82%		7.50%

Note:

(1) Pro forma increase in late payment fees calculated at 0.2499% of total revenue increase.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Determination of Revenue Increase
Rate Year Ended June 30, 2014

		<u>Amount</u>	<u>Source</u>
OCA Recommended Rate Base		\$ 951,550,044	Schedule TSC-2
Required Rate of Return		<u>7.49%</u>	OCA Witness Kahal
Net Operating Income Required		\$ 71,271,098	
Net Operating Income at Present Rates		<u>45,842,444</u>	Schedule TSC-1
Net Income Surplus/(Deficiency)		\$ (25,428,654)	
Revenue Multiplier		<u>1.708172</u>	
Revenue Increase/(Decrease)		<u>\$ 43,436,513</u>	
Revenue Increase/(Decrease)		\$ 43,436,513	
Uncollectibles	1.45800%	<u>\$ 633,304</u>	
Sales Revenue Increase		\$ 42,803,208	
Current State Income Tax	8.602630%	<u>3,682,202</u>	
Federal Taxable Income		\$ 39,121,007	
Federal Income Tax	35.00%	<u>13,692,352</u>	
Net Income Surplus/(Deficiency)		<u>\$ 25,428,654</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Rate Base
Rate Year Ended June 30, 2014

<u>Description</u>	<u>Amount Per Company Filing (1)</u>	<u>OCA Adjustments</u>	<u>Adjusted Per OCA</u>
<u>Plant in Service</u>			
Gas Plant in Service	\$ 1,477,108,215	\$ (75,311,788)	\$ 1,401,796,427
Contruction Work in Progress	-	-	-
Reserve for Depreciation	<u>(343,000,400)</u>	<u>10,380,821</u>	<u>(332,619,579)</u>
Net Utility Plant	\$ 1,134,107,815	\$ (64,930,966)	\$ 1,069,176,849
<u>Additions</u>			
Gas Stored Underground-Noncurrent	\$ 3,794,990	-	\$ 3,794,990
Accum. Provision Gas Lost	(163,458)	-	(163,458)
Gas Storage Inventory	74,526,147	-	74,526,147
Materials & Supplies	663,015	-	663,015
Prepayments	1,651,928	-	1,651,928
Cash Working Capital	-	-	-
Total Additions	<u>\$ 80,472,622</u>	<u>\$ -</u>	<u>\$ 80,472,622</u>
<u>Deductions</u>			
Accumulated Deferred Income Taxes	\$ (200,010,993)	4,800,351	\$ (195,210,642)
Customer Deposits	(2,671,287)	-	(2,671,287)
Customer Advances	<u>(217,497)</u>	<u>-</u>	<u>(217,497)</u>
Total Deductions	<u>\$ (202,899,777)</u>	<u>\$ 4,800,351</u>	<u>\$ (198,099,426)</u>
Total Rate Base	<u>\$ 1,011,680,660</u>	<u>\$ (60,130,616)</u>	<u>\$ 951,550,044</u>

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Adjustments to Rate Base
Rate Year Ended June 30, 2014

	<u>Amount</u>	<u>Source</u>
Rate Base per Company Filing	\$ 1,011,680,660	Exhibit No. 108, page 3
<u>OCA Adjustments</u>		
Average Rate Year Plant	(60,130,616)	Schedule TSC-5
	<u>\$ (60,130,616)</u>	
OCA Adjusted Rate Base	<u>\$ 951,550,044</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Adjustments to Net Income
Rate Year Ended June 30, 2014

	<u>Amount</u>	<u>Source</u>
Income Before Income Taxes per Company	\$ 45,705,272	Ex. 102, Schedule 3
<u>OCA Adjustments</u>		
Rate Year Salaries and Wage Expense-Existing Employees	747,188	Schedule TSC-6
Rate Year Salaries and Wage Expense-New Employees	266,639	Schedule TSC-7
Pension and Benefits Expense	2,973,572	Schedule TSC-8
NCSC Labor and Related Billings	1,101,160	Schedule TSC-9
Profit Sharing Expense	330,067	Schedule TSC-10
Phantom Stock Expense	101,981	Schedule TSC-11
Corporate Insurance	246,074	Schedule TSC-12
Deferred NiFit O&M Amortization	505,000	Schedule TSC-13
GEAC Support and Maintenance	46,919	Schedule TSC-14
Longwall Mining Amortization	42,522	Schedule TSC-15
Lease Expense	67,625	See Note (1)
Depreciation on Average Rate Year Plant	2,098,196	Schedule TSC-16
FICA Taxes	77,036	Schedule TSC-17
Total OCA Adjustments to Income before Taxes	\$ 8,603,978	
OCA Adjusted Income Before Income Taxes	<u>\$ 54,309,250</u>	

Note:

(1) Per response to I&E-RE-96-D.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Adjustments to Operating Income before Income Taxes
Rate Year Ended June 30, 2014

	Revenue	O&M	Depreciation	Taxes Other Than Income	Operating Income Before Taxes
Operating Income per Company	\$ 379,306,896	\$ 287,952,085	\$ 41,961,336	\$ 3,688,203	\$ 45,705,272
<u>OCA Adjustments</u>					
Rate Year Salaries and Wage Expense-Existing Employees		(747,188)			747,188
Rate Year Salaries and Wage Expense-New Employees		(266,639)			266,639
Pension and Benefits Expense		(2,973,572)			2,973,572
NCSC Labor and Related Billings		(1,101,160)			1,101,160
Profit Sharing Expense		(330,067)			330,067
Phantom Stock Expense		(101,981)			101,981
Corporate Insurance		(246,074)			246,074
Deferred NiFit O&M Amortization		(505,000)			505,000
GEAC Support and Maintenance		(46,919)			46,919
Longwall Mining Amortization		(42,522)			42,522
Lease Expense		(67,625)			67,625
Depreciation on Average Rate Year Plant			(2,098,196)		2,098,196
FICA Taxes				(77,036)	77,036
Total OCA Adjustments	\$ -	\$ (6,428,746)	\$ (2,098,196)	\$ (77,036)	\$ 8,603,978
OCA Adjusted Income Before Income Taxes	\$ 379,306,896	\$ 281,523,339	\$ 39,863,140	\$ 3,611,167	\$ 54,309,250

COLUMBIA GAS OF PENNSYLVANIA, INC

Income Tax Reconciliation
Rate Year Ended June 30, 2014

	Amount per Company at Present Rates	OCA Adjustments	Adjusted Per OCA at Present Rates	Proposed Revenue Increase	Amount at Proposed Rates
Operating Income before Taxes	\$ 45,705,272	\$ 8,603,978	\$ 54,309,250	\$ 42,803,208	\$ 97,112,459
Interest Expense	(26,607,201)	1,962,055	(24,645,146)	-	(24,645,146)
Other Flow-Through Adjustments	8,553,745	-	8,553,745	-	8,553,745
Deferral Adjustments	(46,184,688)	-	(46,184,688)	-	(46,184,688)
Total Statutory Adjustments	\$ (64,238,144)	\$ 1,962,055	\$ (62,276,089)	\$ -	\$ (62,276,089)
Taxable Income Subtotal	\$ (18,532,872)	\$ 10,566,033	\$ (7,966,839)	\$ 42,803,208	\$ 34,836,369
Pennsylvania Bonus Depreciation	(5,114,711)	-	(5,114,711)	-	(5,114,711)
State Taxable Income	\$ (23,647,583)	\$ 10,566,033	\$ (13,081,550)	\$ 42,803,208	\$ 29,721,658
Net Operating Loss Deduction	-	-	-	5,944,332	5,944,332
Adjusted State Taxable Income	\$ (23,647,583)	\$ 10,566,033	\$ (13,081,550)	\$ 36,858,877	\$ 23,777,327
Pennsylvania Income Tax at 9.99%	\$ (2,362,394)	\$ 1,055,547	\$ (1,306,847)	\$ 3,682,202	\$ 2,375,355
Deferred State Income Taxes	1,566,210	-	1,566,210	-	1,566,210
Total State Income Taxes	\$ (796,184)	\$ 1,055,547	\$ 259,363	\$ 3,682,202	\$ 3,941,565
Taxable Income Subtotal	(16,170,479)	9,510,487	(6,659,992)	39,121,007	32,461,015
Federal NOL Adjustment	-	-	-	-	-
Current Federal Taxable Income	\$ (16,170,479)	\$ 9,510,487	\$ (6,659,992)	\$ 39,121,007	\$ 32,461,015
Current Federal Income Tax	(5,659,668)	3,328,670	(2,330,997)	13,692,352	11,361,355
Deferred Federal Income Tax	16,164,641	-	16,164,641	-	16,164,641
Tax Refund Amortization	(4,089,420)	-	(4,089,420)	-	(4,089,420)
Flow Back of Excess Deferred Taxes	(628,368)	-	(628,368)	-	(628,368)
Effect of CNIT Deferred on Federal	(548,174)	-	(548,174)	-	(548,174)
Total Federal Income Taxes	\$ 5,239,012	\$ 3,328,670	\$ 8,567,682	\$ 13,692,352	\$ 22,260,034
			\$ 8,827,045		
<u>Calculation of Interest Deduction</u>					
Rate Base	\$ 1,011,680,660		\$ 951,550,044		\$ 951,550,044
Weighted Cost of Debt	2.63%		2.59%		2.59%
Interest Deduction	\$ 26,607,201	\$ (1,962,055)	\$ 24,645,146		\$ 24,645,146
State Income Tax Effect at 9.99%		196,009			
Federal Income Tax Effect at 35%		618,116			
Interest Synchronization Adjustment		\$ 814,125			

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Rate Base to Reflect
13-Month Average Balances of Plant and Related Items
Rate Year Ended June 30, 2014

	June 30, 2014 Balance per Company (1)	13-Month Avg. Balance per OCA	Adjustment
Plant In Service (2)	\$ 1,477,108,215	1,401,796,427	(75,311,788)
Accumulated Depreciation (3)	(343,000,400)	(332,619,579)	10,380,821
Net Utility Plant	\$ 1,134,107,815	\$ 1,069,176,849	\$ (64,930,966)
Accumulated Deferred Income Taxes (4)	(200,010,993)	(195,210,642)	4,800,351
Net Balance	<u>\$ 934,096,822</u>	<u>\$ 873,966,206</u>	<u>\$ (60,130,616)</u>

Notes:

- (1) Amount per Exhibit No. 108, page 3.
- (2) OCA amounts per Exhibit No. 108, Schedule 1.
- (3) OCA amount per response to OCA informal request.
- (4) OCA Amount per response to I&E-RE-135-D.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Rate Year Salaries and Wages
for Existing Employees as of 5/31/2012
Rate Year Ended June 30, 2014

Line No.	As Filed Amount Per Company (1) (A)	Updated Amount Per Company (1) (B)	Amount Per OCA (C)	OCA Adjustment to Filed Amount (D)
1	Historic Test Year Labor (2)	\$ 22,569,598	\$ 22,569,598	\$ -
2	Remove Severance	(30,000)	(30,000)	-
3	Adjustment for Capitalization Percentage (3)(4)	2,170,881	2,170,881	(531,710)
4	Adjusted Historic Test Year Labor	\$ 24,710,479	\$ 24,710,479	\$ (531,710)
Adjustments for Wage Increases				
5	Annualized Labor as of 5/31/2012	926,099	926,099	\$ -
6	Annualized Labor as of 5/31/2013	1,119,229	839,675	(279,554)
7	Merit Increase Effective June 1, 2013	-	328,937	328,937
8	Annualized Rate Year Increases through 6/30/2014	856,891	1,133,539	(856,891)
9	Increases Paid during 12 months ending 6/30/2014 (5)	-	544,868	544,868
10	Total Adjustments	\$ 2,902,219	\$ 3,228,250	\$ (262,640)
11	Percent to O&M (2)(7)	67.47%	67.47%	66.02%
12	Increase in O&M for Wage Increases	\$ 1,958,127	\$ 2,178,100	\$ (215,477)
13	Rate Year Labor	\$ 26,668,606	\$ 26,888,579	\$ (747,188)

Notes:

- (1) Per supplemental response to OCA I-15.
- (2) Per Exhibit No. 4, Schedule 1 and Exhibit No. 104 Schedule 2, page 1.
- (3) Company amounts calculated on Exhibit No. 4, Schedule 2 page 7.
- (4) OCA amount calculated as amount in Note (3), with 5 year avg O&M percentage of 66.02% per Note (6).
- (5) Calculated based on the supplemental response to OCA I-15.
- (6) OCA percentage calculated at follows:

12 Months Ending 12/31/2008	66.0311%
12 Months Ending 12/31/2009	67.5085%
12 Months Ending 12/31/2010	70.0440%
12 Months Ending 12/31/2011	64.2808%
12 Months Ending 10/31/2012	62.2408%
5-Year Average	66.0200%

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Rate Year Salaries and Wages
for Existing Employees as of 5/31/2012
Rate Year Ended June 30, 2014

Line No.	As Filed Amount Per Company (1) (A)	Updated Amount Per Company (1) (B)	Amount Per OCA (C)	OCA Adjustment to Filed Amount (D)
1 Future Test Year Labor (2)	\$ 1,272,250	\$ 1,011,523	\$ 1,011,523	\$ (260,727)
Adjustments for Wage Increases				
2 Merit Increase Effective June 1, 2013	-	3,375	3,375	3,375
3 Annualized Rate Year Increases through 6/30/2014	27,368	29,805	-	(27,368)
4 Increases Paid during 12 months ending 6/30/2014 (3)	-	-	18,081	18,081
5 Rate Year Adjustments	\$ 27,368	\$ 33,180	\$ 21,456	\$ (5,912)
6 Rate Year Labor	<u>\$ 1,299,618</u>	<u>\$ 1,044,703</u>	<u>\$ 1,032,979</u>	<u>\$ (266,639)</u>

Notes:

(1) Per supplemental response to OCA I-15.

(2) Per Exhibit No. 104, Schedule 2, page 10.

(3) Calculated based on the supplemental response to OCA I-15.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Pension & Benefits Expense
to Reflect Rate Year Amounts
Rate Year Ended June 30, 2014

	2013 Gross Cost (1)	2014 Gross Cost (2)	Rate Year Gross Cost	Percent to O&M (3)	Rate Year Expense	Cost for New Employees 34.51% To O&M (4)	Adjusted Expense Per OCA	2014 Expense per Company (2)	Adjustment to Rate Year Expense
PENSION AND RETIREMENT INCOME PLANS									
Retirement Income Plan (5)	\$ -	\$ 3,249,000	\$ 1,624,500	66.02%	1,072,495	N/A	\$ 1,072,495	\$ 3,743,348	(2,670,853)
Supplemental Retirement Income Plan	3,000	5,000	4,000	66.02%	2,641	N/A	3,382	3,382	(741)
Total Pensions and Retirement Income	\$ 3,000	\$ 3,254,000	\$ 1,628,500		\$ 1,075,136	\$ -	\$ 1,075,136	\$ 3,746,730	\$ (2,671,594)
OPEB COST									
Ongoing OPEB - Medical	-	-	-	66.02%	-	N/A	-	-	-
Ongoing OPEB - Group Life	-	-	-	66.02%	-	N/A	-	-	-
SFAS 106 Amortization	-	-	-	66.02%	-	N/A	-	-	-
Total SFAS 106 Cost	\$ -	\$ -	\$ -		\$ -	\$ -	\$ -	\$ -	\$ -
SFAS 112	138,824	138,824	138,824	100.00%	138,824	N/A	138,824	138,824	-
OPEB difference between expense and recovery	-	-	-	100.00%	-	N/A	-	0	-
OPEB Overcollection Post Rate Case	(303,697)	(303,697)	(303,697)	100.00%	(303,697)	N/A	(303,697)	(303,697)	-
Total SFAS 112 Costs	\$ (164,873)	\$ (164,873)	(164,873)		\$ (164,873)	\$ -	\$ (164,873)	\$ (164,873)	\$ -
EMPLOYEES' INSURANCE PLANS & OTHER									
Comp Medical Insurance and EAP	4,201,000	4,583,000	4,392,000	66.02%	2,899,598	163,456	3,063,054	3,280,714	(217,660)
Dental Assistance	309,000	323,000	316,000	66.02%	208,623	11,760	220,384	231,218	(10,834)
Group Life Insurance	114,000	118,000	116,000	66.02%	76,583	4,317	80,900	84,470	(3,570)
Long Term Disability	289,000	298,000	293,500	66.02%	193,769	10,923	204,692	213,322	(8,630)
Total Employees' Insurance Plans	\$ 4,913,000	\$ 5,322,000	\$ 5,117,500		\$ 3,378,574	\$ 190,456	\$ 3,569,030	\$ 3,809,724	\$ (240,694)
Thrift Plan	1,727,000	1,778,000	1,752,500	66.02%	1,157,001	\$ 65,222	1,222,223	1,272,772	(50,549)
Profit Sharing	315,000	324,000	319,500	66.02%	210,934	11,891	222,825	231,934	(9,109)
Inter-Company Billing	112,071	112,071	112,071	66.02%	73,989	-	73,989	75,614	(1,625)
Total Employees' Insurance Plans and Other	\$ 7,067,071	\$ 7,536,071	\$ 7,301,571		\$ 4,820,497	\$ 267,569	\$ 5,088,066	\$ 5,390,044	\$ (301,978)
Total Pension and Benefits	\$ 6,905,198	\$ 10,625,198	\$ 8,765,198		\$ 5,730,760	\$ 267,569	\$ 5,998,329	\$ 8,971,901	<u>\$ (2,973,572)</u>

Notes:

- (1) Per Exhibit No. 104, Schedule 2, page 11, except where noted.
- (2) Per Exhibit No. 104, Schedule 2, page 12, except where noted.
- (3) Reflects average percentage for 2008-2012 as shown in Note (6) on Schedule TSC-6.
- (4) Reflects Rate Year Gross Cost divided by 510 existing employees times 55 new employees time percent to O&M for new employees per supplemental response to OCA I-15.
- (5) Retirement income plan amounts per response to I&E-RE-59-D.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to NCSC Labor and Related Billings
Rate Year Ended June 30, 2014

Total Rate Year NCSC Labor and Related Billings (1)	\$ 18,913,751
Percent Allocated to Columbia per OCA (2)	10.93%
Percent Allocated to Columbia per Company (3)	11.22%
Adjusted Rate Year NCSC Labor and Related Billings	<u>\$ 18,424,893</u>
Adjustment to Rate Year Expense To Reflect Average Allocator	<u>\$ (488,858)</u>
Projected Rate Year New Headcount Labor per Company (1)	\$ 298,813
Ratio of Labor Allocators (4)	97.42%
New Headcount Labor Restated for Change in Allocators	<u>\$ 291,090</u>
New Headcount Employee Expenses (1)	<u>34,421</u>
Adjustment to Remove Costs for Rate Year Headcount Increase	<u>\$ (325,511)</u>
Differences between Rate Year Cost and Annualized End of Rate Year Cost (5)	\$ (294,401)
Ratio of Labor Allocators (4)	<u>97.42%</u>
Adjustment to Reflect Annual Labor and Related Expense during Rate Year	<u>\$ (286,792)</u>
Total Adjustment to NCSC Labor and Related Billings	<u>\$ (1,101,160)</u>

Notes:

- (1) Per Exhibit No. 104, Schedule No. 2, page 27.
- (2) Reflects percentage for the HTY per Exhibit No. 4, Schedule 2, page 23.
- (3) Reflects percentage for May 2012 per Exhibit No. 4, Schedule 2, page 23.
- (4) Equals 10.93% divided by 11.22%.
- (5) Refer to page 2 of this schedule.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Calculation of Difference Between
Rate Year Expense and Annualized End of Rate Year
for NCSC Labor and Related Costs
Rate Year Ended June 30, 2014

	2014 Annualized Amount Per Company	Rate Year Amount Per OCA	Rate Year vs. Annualized Difference (4)
2014 Payroll and Benefit Increase (1)	\$ 439,904	\$ 146,500	\$ (293,404)
Incentive Compensation (2)	104,137	52,068	(52,069)
Pension (3)	(102,498)	(51,426)	51,072
Total	\$ 441,543	\$ 147,142	\$ (294,401)

Notes:

(1) Per Exhibit No. 104, Schedule 2, page 29.

(2) Per Exhibit No. 104, Schedule 2, page 28.

(3) Per Exhibit No. 104, Schedule 2, page 30.

(4) Reflects differences before accounting for OCA Adjustment to percentage allocation to Columbia.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Profit Sharing Expense
Rate Year Ended June 30, 2014

<u>Profit Sharing Plan Expense</u>	<u>Amount</u>
Company Employees (1)	\$ 222,825
NCSC Charges (2)	<u>107,243</u>
Adjustment to Eliminate Profit Sharing Plan Expense	<u>\$ (330,067)</u>

Notes:

- (1) Per Exhibit No. 104, Schedule 2, Page 12, as adjusted on Schedule TSC-8
- (2) Reflects amount per response to OCA I-12 of \$112,683 adjusted to exclude one-half of the rate year increase of \$5,190 and to reflect the average annual allocation to Columbia rather than the May 2012 allocation as discussed with regard to the adjustment to NCSC labor costs shown on Schedule TSC-9.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Phantom Stock Expense
Rate Year Ended June 30, 2014

	<u>Amount</u>
Phantom Stock Expense per Company (1)	\$ 101,981
Allowable Expense per OCA	<u>-</u>
Adjustment to Eliminate Phantom Stock Expense	<u><u>\$ (101,981)</u></u>

Note:

(1) Per response to OCA 1-12.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Corporate Insurance Expense
Rate Year Ended June 30, 2014

	Premiums for the 12 Months Ending 6/30/2013 (1)	Premiums for the 12 Months Ending 6/30/2014 (2)	Amount per Company (3)	Adjustment
	(A)	(B)=(A) x 1.56%	(C)	
Property Insurance	\$ 245,075	\$ 248,898	\$ 270,196	\$ (21,298)
Other Liability Insurance	2,124,029	2,157,164	2,341,743	(184,579)
Workers Compensation	<u>547,982</u>	<u>556,531</u>	<u>604,151</u>	<u>(47,620)</u>
Total Corporate Insurance Premiums	\$ 2,917,086	\$ 2,962,593	\$ 3,216,090	\$ (253,497)
Workers Compensation Tranferred to Capital (4)	<u>(186,204)</u>	<u>(189,109)</u>	<u>(196,533)</u>	<u>7,424</u>
Total Corporate Insurance Expesne	\$ 2,730,882	\$ 2,773,483	\$ 3,019,557	<u>\$ (246,074)</u>

Notes:

- (1) Per response to OCA VI-4 and Exhibit No. 104, Schedule 2, page 16.
- (2) Column A times increase in the GDP Deflator per Exhibit No. 104, Schedule 2, page 21.
- (3) Per Exhibit No. 104, Schedule 2, page 16.
- (4) Amounts in columns (A) and (B) reflect updated percent capitalized per Schedule TSC-6.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Deferred NiFit Cost Amortization
Rate Year Ended June 30, 2014

	<u>Amount</u>
Deferred NiFit Costs (1)	\$ 2,020,000
OCA Proposed Amortization Period	<u>4 Years</u>
Annual Amortization Expense per OCA	\$ 505,000
Annual Amortization Expense per Company (2)	<u>1,010,000</u>
Adjustment to NiFit Amortization Expense	<u>\$ (505,000)</u>

Notes:

- (1) Per Direct Testimony of Columbia witnesses Richard Fontaine and Jeffery T. Gore.
- (2) Per Exhibit No. 104, Schedule 1, page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Eliminate GEAC Financial Software Costs
Rate Year Ended June 30, 2014

	<u>Amount</u>
GEAC Support and Maintenance Costs in HTY (1)	\$ 45,359
Inflation Factor for HTY to FTY (2)	1.0185
Inflation Factor for FTY to FFRY (3)	<u>1.0156</u>
Adjustment to Eliminate GEAC Support and Maintenance Costs	<u><u>\$ (46,919)</u></u>

Notes:

- (1) Per response to OCA II-5.
- (2) Per Exhibit No. 104, Schedule 2, page 22.
- (3) Per Exhibit No. 104, Schedule 2, page 27.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Longwall Mining Costs
Rate Year Ended June 30, 2014

	<u>Amount</u>
Longwall Mining Costs in HTY (1)	\$ 54,210
Inflation Factor for HTY to FTY (2)	1.0185
Inflation Factor for FTY to FFRY (2)	<u>1.0156</u>
Longwall Mining Costs in FFRY per Company	\$ 56,074
Rate Year Amortization of Remaining Balance at 6/30/2013 (1)	<u>13,552</u>
Adjustment to Longwall Mining Costs	<u><u>\$ (42,522)</u></u>

Notes:

(1) Per response to I&E-RE-133.

(2) Per Exhibit No. 104, Schedule 2, page 21.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Depreciation Expense
Rate Year Ended June 30, 2014

	<u>Amount</u>
13 Month Average Balance of Plant in Service (1)	\$ 1,401,796,427
Less: 13 Month Average of Amortization and Non-Depreciable Plant (2)	<u>(12,749,406)</u>
13 Month Average Balance of Depreciable Plant in Service	\$ 1,389,047,021
Composite Depreciation Rate (3)	<u>2.3801%</u>
Depreciation Expense	\$ 33,060,372.92
Amortization Expense (4)	<u>1,938,436</u>
Rate Year Depreciation and Amortization per OCA	\$ 34,998,809
Rate Year Depreciation and Amortization as of 6/30/2014 per Company (5)	<u>\$ 37,097,005</u>
Adjustment to Depreciation Expense	<u><u>\$ (2,098,196)</u></u>

Notes:

- (1) Per Schedule TSC-5.
- (2) Per Exhibit No. 108, Schedule 1. Reflects Accounts 303, 374.2, 375.71, and non-depreciable plant consistent with Exhibit No. 105.
- (3) Based on depreciation expense divided by depreciable plant per Exhibit No. 105, pages 7-10.
- (4) Reflects amortization at 6/30/2014.
- (5) Per Exhibit No. 105. Excludes negative net salvage.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to FICA Tax Expense
Rate Year Ended June 30, 2014

	<u>Taxable for Social Security</u>	<u>Taxable for Medicare</u>
Adjustment to Labor Expense for Existing Employees (1)	\$ (747,188)	\$ (747,188)
Adjustment to Labor Expense for New Employees (2)	<u>(266,639)</u>	<u>(266,639)</u>
OCA Adjustment to Labor Expense	\$ (1,013,827)	\$ (1,013,827)
Percent Taxable (3)	<u>99.17%</u>	<u>100.00%</u>
Taxable Base	\$ (1,005,412)	\$ (1,013,827)
Tax Rate	<u>6.20%</u>	<u>1.45%</u>
Total Tax Amount	\$ (62,336)	\$ (14,700)
Adjustment to FICA Tax Expense for OCA Wage Adjustments		<u><u>\$ (77,036)</u></u>

Notes:

- (1) Per Schedule TSC-6.
- (2) Per Schedule TSC-7.
- (3) Per response to I&E-RE-128.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	)	
	)	
v	)	Docket Nos. R-2012-2321748
	)	M-2012-2323645
Columbia Gas of Pennsylvania, Inc.	)	

**SURREBUTTAL TESTIMONY
OF
THOMAS S. CATLIN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE**

FEBRUARY 8, 2013

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ASSOCIATES, INC.
10480 Little Patuxent Parkway
Suite 300
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2-13-13
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Purpose

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

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of the Pennsylvania Office of Consumer Advocate (OCA) on January 4, 2013. That testimony has been identified as OCA Statement No. 1 and my qualifications and experience are set forth in that testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony submitted on behalf of Columbia Gas of Pennsylvania (Columbia or the Company). In particular, I will address the rebuttal testimony of Ms. Nancy Krajovic, Mr. Jeffery Gore, Mr. John Spanos, Mr. Gregory Shoemaker and Mr. Joel Hoelzer. In addition to responding to Columbia's rebuttal, I will also update the OCA's recommendations with regard to the Company's revenue requirements.

Response to Ms. Krajovic

Q. WHAT POSITION HAS MS. KRAJOVIC TAKEN IN RESPONSE TO YOUR TESTIMONY ON DETERMINING RATE YEAR, RATE BASE AND EXPENSES?

1 A. In her rebuttal testimony, Ms. Krajovic argues that Columbia's approach of adjusting
2 rate base and operating expenses to reflect end of rate year levels is appropriate for
3 two reasons.¹ First, it is consistent with the procedures that Columbia has used in
4 prior cases with the exception that no CWIP has been claimed in this case. Second, if
5 the rate year average rate base is used as I have recommended, it would affect the use
6 of the DSIC.

7 Q. WHAT RESPONSE DO YOU HAVE TO MS. KRAJOVIC?

8 A. In response to Ms. Krajovic's argument that Columbia's approach is appropriate
9 because it is the same procedure that it has used in prior cases, I addressed that
10 argument extensively in my direct testimony. In summary, this is the first case in
11 which Columbia is using a fully forecasted test year or rate year that corresponds to
12 the first year that the approved rates will be in effect. In prior cases, the future test
13 (FTY) ended before rates took effect. Hence, adjusting rate base and expenses to end
14 of FTY levels permitted rates to be set based on costs that would be incurred at the
15 time rates went into effect. Adjusting rate base and expenses to end of year levels for
16 a fully forecasted rate year would result in rates being set based on costs in excess of
17 the costs that would be incurred during the first year the rates would be in effect. As
18 a result Columbia would earn well in excess of its allowed rate of return.

19 Q. HAVE YOU ESTIMATED THE EXCESS EARNINGS THAT COLUMBIA
20 WILL REALIZE DURING THE RATE YEAR IF ITS PROPOSAL TO
21 UTILIZE END OF RATE YEAR RATE BASE AND EXPENSES IS
22 ACCEPTED?

23 A. Yes. To determine the excess earnings Columbia would realize during the rate year, I
24 started with revenues including Columbia's requested revenue increase and its

¹ As in my direct testimony, I have used rate year to refer to the twelve months ended June 30, 2014. Columbia refers to this as the fully forecasted rate year or FFRY.

1 claimed revenue requirements.² I then adjusted the Company's rate base to reflect the
2 13-month average and adjusted expenses to reflect the amounts that would be
3 incurred during the rate year. This analysis showed that Columbia would earn a
4 return on equity of 12.57 percent instead of the 11.25 percent it has requested and
5 revenues would be \$10.8 million in excess of those required to generate its claimed
6 return on equity.

7 Q. DOES YOUR CALCULATION INCLUDE ANY ADJUSTMENT OTHER
8 THAN THOSE NECESSARY TO REFLECT THE COSTS THAT WILL BE
9 INCURRED DURING THE RATE YEAR?

10 A. No. I have not included any of the other adjustments that I am recommending such as
11 eliminating profit sharing and Phantom Stock expense or revising pension expense to
12 reflect the average of the 2013 and 2014 contributions.

13 Q. WHAT COMMENTS DO YOU HAVE WITH REGARD TO MS.
14 KRAJOVIC'S ARGUMENT REGARDING THE IMPLICATIONS TO THE
15 DSIC OF YOUR PROPOSAL TO UTILIZE AVERAGE RATE BASE?

16 A. The required revenue in this case should be determined based on the costs that will be
17 incurred during the first year the rates are in effect so that Columbia will have the
18 opportunity to earn its allowed rate of return during the rate year. The availability of
19 a DSIC to recover eligible investment does not justify setting rates to generate an
20 excessive return. The DSIC procedures include a rate of return test. If Columbia
21 meets this test and the other DSIC requirements, then it should be allowed to recover
22 eligible investment through its DSIC (if it is approved).
23

² For purposes of this analyses, I excluded the claimed revenue increase and costs associated with the \$3.2 million of incremental capital spending which Columbia accounted for separately.

Response to Jeffrey T. Gore

Q. WHAT RESPONSE DO YOU HAVE TO MR. GORE'S REBUTTAL TESTIMONY?

A. I would like to respond to Mr. Gore's rebuttal testimony regarding labor expense pension expense and the amortization of NiFit costs. With regard to labor expense, I would simply like to note that other than differences related to recognizing the expenses that will be incurred during the rate year instead of annualized costs as of the end of the rate year, as addressed in my response to Ms. Krajovic, there are no remaining differences between Columbia's and the OCA's positions on rate year labor expense. The differences in the updated wages for new employees and the percentage of wages charged to O&M that I addressed in my direct testimony have been incorporated in Mr. Gore's rebuttal exhibits.

With regard to pension expense, Mr. Gore argues that the Company's three-year average of pension expense should be used because (1) Columbia made a large pension contribution in late 2011 that affected subsequent contributions for 2012, 2013 and 2014 and (2) the three-year average more accurately reflects the expected contributions in 2015 and 2016. With regard to the contribution in late 2011, while that contribution of \$13.1 million exceeded the ongoing pension expense of \$8.9 million that Columbia claimed in its last case, it was not so much above the expected contribution in 2012 that it would eliminate both the 2012 and 2013 contributions and significantly reduce the 2014 contribution. The fact is that pension contributions frequently differ from those expected at the time of a rate case because of investment performance, actuarial changes and other factors. There is also no reason to base pension expense for the rate year ended June 30, 2014 on what Columbia now estimates its contributions will be in 2015 and 2016. The pension expense that I

1 have recommended based on a two-year average for 2013 and 2014 should be utilized
2 because it reflects the costs that will be incurred in the rate year.

3 With regard to NiFit costs, Mr Gore argues that the Company's proposed two-
4 year amortization is consistent with the amortization period proposed for other items
5 including rate case expense, the pass-back of a remaining tax refund and the pass-
6 back of the OPEB deferral. I do not dispute that is the case but, as I noted in my
7 direct testimony, the deferred NiFit costs are associated with a new accounting
8 system with an expected life of 10 years. In addition, spreading out the amortization
9 period over four years instead of two will help to reduce the large rate increase likely
10 to occur in this case. Therefore, I continue to recommend a four-year amortization
11 period.

12
13 **Response to Mr. Spanos**

14 Q. PLEASE SUMMARIZE THE ADJUSTMENT YOU RECOMMENDED TO
15 COLUMBIA'S DEPRECIATION CLAIM IN YOUR DIRECT
16 TESTIMONY.

17 A. In my direct testimony, I adjusted depreciation expense to reflect the depreciation
18 expense that Columbia will incur during the rate year rather than depreciation
19 expense based on end of rate year plant in service plus construction work in progress
20 (CWIP), as reflected in Columbia's filing. To estimate rate year depreciation
21 expense, I calculated a composite depreciation rate based upon Mr. Spanos'
22 recommended depreciation expense at end of rate year plant levels and multiplied that
23 rate by the 13-month average balance of depreciable plant. I then added amortization
24 expense at end of rate year levels even though that amount included a full year of
25 amortization of the new NiFit system expected to be placed in service in February

1 2014. I made no adjustment to the amortization of net salvage because that amount
2 was based on net salvage for the years 2009 through 2013 and therefore, would be
3 consistent with the expense during the rate year.

4 Q. PLEASE SUMMARIZE MR. SPANOS' CRITICISM OF YOUR
5 ADJUSTMENT IN HIS REBUTTAL TESTIMONY.

6 A. In his rebuttal testimony, Mr. Spanos criticizes the way I have calculated my
7 adjustment to depreciation expense. In particular he criticizes my use of a composite
8 depreciation rate based on rate year end plant to calculation depreciation expense
9 associated with the average plant balance during the rate year. He notes that
10 calculation of depreciation expense for the future test year is not a simple average as I
11 have proposed. Mr. Spanos did agree to adjust depreciation expense to exclude the
12 amount associated with CWIP.

13 Q. WHAT COMMENTS DO YOU HAVE WITH REGARD TO MR. SPANOS'
14 REBUTTAL TESTIMONY?

15 A. I would acknowledge that the approach I used is not as accurate as recalculating
16 depreciation rates and expense each month as Mr. Spanos seems to suggest is
17 necessary. However, it is also the case that depreciation expense for a future period,
18 no matter how it is estimated, will not be accurate for other reasons such as plant
19 additions and retirements undoubtedly differing from the Company's projections.
20 However, in light of Mr. Spanos' criticisms, I have submitted a data request asking
21 Columbia to identify the depreciation expense that it estimates that it will incur
22 during the rate year assuming that the depreciation rates it has proposed in this
23 proceeding are approved and its projections of plant in service during the rate year are
24 accurate.

1 Q. HAVE YOU UPDATED YOUR ADJUSTMENT TO DEPRECIATION
2 EXPENSE?

3 A. Yes. I have updated my adjustment to depreciation to recognize that Columbia has
4 eliminated its claim for depreciation expense of the projected June 30, 2014 balance
5 of CWIP in its rebuttal filing. This change is shown on Schedule TSC-16S.
6 However, I have not updated my adjustment for the depreciation expense that will be
7 incurred during the rate year because I have not received the response to my
8 discovery request. I will update my recommended adjustment after I receive that
9 response.

10

11 **Response to Mr. Shoemaker**

12 Q. WHAT RESPONSE DO YOU HAVE TO MR. SHOEMAKER'S
13 REBUTTAL TESTIMONY REGARDING NCSC LABOR AND BENEFITS
14 COSTS?

15 A. In his rebuttal, Mr. Shoemaker responds to each of my three adjustments to the
16 projected NiSource Corporation Service Company (NCSC) labor and benefits that
17 Columbia has claimed for the rate year. First, Mr. Shoemaker argues that my
18 adjustment to reflect the average percentage of labor costs charged to Columbia
19 during the historical test year (HTY) instead of using the single month percentage for
20 May 2012, the final month of the HTY, should not be accepted. He claims that the
21 11.20 percent in May 2012 is representative because it is consistent with the average
22 for June through December 2012.

23 Q. DO YOU AGREE?

24 A. No. In discovery, Columbia acknowledged that the percentage of labor costs varies
25 from month to month. (This can easily be seen from Mr. Shoemaker's Exhibit GLS-

1 1R, which shows the percentage varied from 10.3 percent to 12.1 percent from June
2 through December of 2012.) For this reason, it is inappropriate to rely on a single
3 month as being representative of the percentage of NCSC labor costs that will be
4 charged to Columbia in the rate year.

5 Q. ARE YOU PROPOSING ANY CHANGE TO THE PERCENTAGE OF
6 NCSC LABOR RELATED COSTS CHARGED TO COLUMBIA THAT
7 YOU ARE RECOMMENDING?

8 A. Yes. Based on the data presented on Exhibit GLS-1R, I am proposing to update the
9 percentage of NCSC labor related costs billed to Columbia from 10.93 percent for the
10 HTY to 11.1 percent based on the 12 months ended December 2012. Updating to
11 reflect this most recent experience is consistent with updating the percentage of
12 Columbia's wages charged to O&M and other updates made by Columbia and the
13 OCA.

14 Q. WHAT WAS YOUR SECOND ADJUSTMENT TO WHICH MR.
15 SHOEMAKER RESPONDED?

16 A. Mr. Shoemaker disagreed with my adjustment to reduce NCSC charges to exclude the
17 cost for additional employees projected to be hired during the rate year. Based on the
18 updated hiring data provided by Mr. Shoemaker, I have modified my
19 recommendation and have included the projected rate year labor and related expenses
20 for the new NCSC employees projected to be hired in the rate year. I would note that
21 I have adjusted Columbia's claimed expense for these new employees to include only
22 the expenses projected to be incurred during the rate year rather than the annualized
23 costs as of the end of the rate year.

24 Q. WHAT RESPONSE DID MR. SHOEMAKER HAVE WITH REGARD TO
25 YOUR FINAL ADJUSTMENT TO NCSC COSTS?

1 A. Mr. Shoemaker noted that he disagreed with my adjustment to reflect the NCSC costs
2 that will be billed to Columbia during the rate year instead of reflecting annualized
3 costs as of the end of the rate year. He noted that Ms. Krajovic was addressing that
4 issue and I have previously responded to Ms. Krajovic's rebuttal testimony regarding
5 the determination of rate year costs.

6 Q. HAVE YOU UPDATED YOUR ADJUSTMENT TO NCSC BILLINGS?

7 A. Yes. Schedule TSC-9S presents my updated adjustment after incorporating the
8 changes discussed above. I have also included the correction to NCSC pension
9 expense that Mr. Gore has incorporated in Columbia's updated revenue requirement
10 request. As shown on Schedule TSC-9S, my updated adjustment to NCSC billings
11 reduces rate year expenses by \$740,429.

12 Q. DID MR. SHOEMAKER ADDRESS ANY OF YOUR OTHER
13 RECOMMENDATIONS?

14 A. Yes. Mr. Shoemaker indicated that he disagrees with my adjustment to remove
15 GEAC support and maintenance costs. He indicates that Columbia did not include
16 any similar costs for the NiFit system that is replacing the GEAC system and that the
17 GEAC support and maintenance costs should be included as a substitute for the NiFit
18 support costs. Based on this explanation and considering the small amount of money
19 involved (\$46,919), I have accepted Mr. Shoemaker's position and am no longer
20 proposing to remove the GEAC support and maintenance costs.

21

22 **Response to Joel L. Hoelzer**

23 Q. AFTER REVIEWING MR. HOELZER'S REBUTTAL TESTIMONY, ARE
24 YOU MODIFYING YOUR RECOMMENDATION REGARDING PROFIT
25 SHARING OR PHANTOM STOCK COMPENSATION EXPENSE?

1 A. No. Mr. Hoelzer argues that recovery of profit sharing expense and Phantom Stock
2 expense from ratepayers should be allowed because they are important components of
3 the Company's overall compensation package. In response, I would first like to
4 clarify that I am not recommending the discontinuance of these compensation
5 programs. Rather, I am recommending that those costs not be recovered from
6 ratepayers for the reasons set forth in my direct testimony.

7 Unlike the Company's incentive compensation and equity awards program,
8 profit sharing plan payouts are based solely on the achievement of financial goals.
9 Moreover, these payouts are a small portion of Columbia and NiSource's retirement
10 plan offerings to employees and are in addition to the Retirement Income Plan and
11 Thrift Plan. Finally profit sharing plan contributions are discretionary, not mandatory
12 payments like those associated with the Retirement Income Plan and Thrift Plan.

13 With regard to Phantom Stock, the amounts that Columbia is claiming
14 represent dividends on stock issued to certain NiSource Executives in conjunction
15 with the acquisition of Columbia by NiSource. Columbia has provided no
16 justification for including stock dividends on Phantom Stock in the cost of service,
17 unlike dividends on any other stock.

18

19 **Update of OCA's Recommendation**

20 Q. PLEASE SUMMARIZE YOUR UPDATED FINDINGS REGARDING
21 COLUMBIA'S REVENUE REQUIREMENT.

22 A. As shown on my updated Schedule TSC-1S, I have determined that the Company has
23 a revenue deficiency of \$42,808,480 for the rate year ended June 30, 2014. In
24 calculating this amount, I have included the 13-month average rate year rate base and
25 the rate year depreciation expense associated with the additional \$3.2 million of

1 capital spending claimed by Columbia in its rebuttal filing. This amount represents a
2 reduction of \$30,874,404 compared to Columbia's updated request of \$73,682,8842
3 as presented in Exhibit JTG-R2, Schedule 3. This represents the amount by which
4 Columbia's' revenues at present rates exceed those required to generate the overall
5 rate of return of 7.49 percent recommended by Mr. Kahal on behalf of the OCA. The
6 OCA's final recommendations regarding the appropriate adjustments to rate base and
7 net income are presented on Schedules TSC-2S and TSC-3S, respectively. Schedule
8 TSC-4S provides a proof of income taxes at present and proposed rates.

9 Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

10 A. Yes, it does. However, I would note at the time I prepared my analysis, I am awaiting
11 responses to the data requests submitted regarding the Company's rebuttal testimony.
12 My determination of Columbia's overall revenue requirement will change because I
13 have been unable to updated depreciation expense and the balance of accumulated
14 depreciation without those responses. I may also need to file additional surrebuttal
15 testimony on the issues of NCSC labor costs, profit sharing expense, Phantom Stock
16 expense and the recognition of plastic pipe settlement payments to Columbia based
17 on those responses.

165755

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	)	
	)	
v	)	Docket Nos. R-2012-2321748
	)	M-2012-2323645
Columbia Gas of Pennsylvania, Inc.	)	

**SCHEDULES ACCOMPANYING THE
SURREBUTTAL TESTIMONY
OF
THOMAS S. CATLIN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE**

FEBRUARY 7, 2013

EXETER

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

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Operating Income
Rate Year Ended June 30, 2014

	Company Amounts at Present Rates (1)	OCA Adjustments	Amounts per OCA at Present Rates	Pro Forma Increase	Amounts at Proposed Rates
<u>Operating Revenue</u>					
Base Rate Revenue	\$ 214,992,936		\$ 214,992,936	\$ 42,701,501	\$ 257,694,437
Gas Cost Revenue	150,198,627		150,198,627	-	150,198,627
Rider USP	10,858,071		10,858,071	-	10,858,071
Storage Interest	-		-	-	-
Unbundled Uncollectibles-Gas Costs	1,848,276		1,848,276	-	1,848,276
Late Payment Fees (1)	1,137,995		1,137,995	106,978	1,244,973
Other Operating Revenue	632,768		632,768	-	632,768
Total Revenue	\$ 379,668,673	\$ -	\$ 379,668,673	\$ 42,808,480	\$ 422,477,153
<u>Operating Revenue Deductions</u>					
Operation & Maintenance Expense					
Purchased Gas Costs	150,198,627		150,198,627	-	150,198,627
Other	135,906,852	(4,830,073)	131,076,779	624,148	131,700,926
Depreciation Expense	41,399,613	(1,483,706)	39,915,907	-	39,915,907
Taxes Other Than Income	3,643,845	(30,741)	3,613,104	-	3,613,104
Total Operating Revenue Deductions	\$ 331,148,937	\$ (6,344,521)	\$ 324,804,416	\$ 624,148	\$ 325,428,564
Operating Income Before Taxes	\$ 48,519,736	\$ 6,344,521	\$ 54,864,257	\$ 42,184,332	\$ 97,048,589
<u>Income Taxes</u>					
State Income Tax	1,448,912	836,779	2,285,691	3,467,236	5,752,927
Federal Income Tax	5,581,766	2,638,787	8,220,553	13,550,984	21,771,537
Investment Tax Credit	(360,239)	-	(360,239)	-	(360,239)
Total Income Taxes	\$ 6,670,439	\$ 3,475,566	\$ 10,146,005	17,018,219	\$ 27,164,225
Utility Operating Income	\$ 41,849,297	\$ 2,868,955	\$ 44,718,251	25,166,113	\$ 69,884,364
Rate Base	\$ 996,093,941	(63,058,366)	\$ 933,035,575		\$ 933,035,575
Rate of Return	4.20%		4.79%		7.49%

Note:

(1) Pro forma increase in late payment fees calculated at 0.2499% of total revenue increase.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Determination of Revenue Increase
Rate Year Ended June 30, 2014

		<u>Amount</u>	<u>Source</u>
OCA Recommended Rate Base		\$ 933,035,575	Schedule TSC-2S
Required Rate of Return		<u>7.49%</u>	OCA Witness Kahal
Net Operating Income Required		\$ 69,884,365	
Net Operating Income at Present Rates		<u>44,718,251</u>	Schedule TSC-1S
Net Income Surplus/(Deficiency)		\$ (25,166,113)	
Revenue Multiplier		<u>1.701037</u>	
Revenue Increase/(Decrease)		<u>\$ 42,808,480</u>	
Revenue Increase/(Decrease)		\$ 42,808,480	
Uncollectibles	1.45800%	<u>\$ 624,148</u>	
Sales Revenue Increase		\$ 42,184,332	
Current State Income Tax	8.219250%	<u>3,467,236</u>	
Federal Taxable Income		\$ 38,717,097	
Federal Income Tax	35.00%	<u>13,550,984</u>	
Net Income Surplus/(Deficiency)		<u>\$ 25,166,113</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Rate Base
Rate Year Ended June 30, 2014

<u>Description</u>	<u>Amount Per Company Filing (1)</u>	<u>OCA Adjustments</u>	<u>Adjusted Per OCA</u>
<u>Plant in Service</u>			
Gas Plant in Service	\$ 1,477,108,215	\$ (72,890,865)	\$ 1,404,217,350
Construction Work in Progress	-	-	-
Reserve for Depreciation	(340,952,106)	8,311,554	(332,640,552)
Net Utility Plant	\$ 1,136,156,109	\$ (64,579,311)	\$ 1,071,576,798
<u>Additions</u>			
Gas Stored Underground-Noncurrent	\$ 3,794,990	-	\$ 3,794,990
Accum. Provision Gas Lost	(163,458)	-	(163,458)
Gas Storage Inventory	74,526,147	-	74,526,147
Materials & Supplies	663,015	-	663,015
Prepayments	1,651,928	-	1,651,928
Cash Working Capital	-	-	-
Total Additions	\$ 80,472,622	\$ -	\$ 80,472,622
<u>Deductions</u>			
Accumulated Deferred Income Taxes	\$ (217,646,006)	1,520,945	\$ (216,125,061)
Customer Deposits	(2,671,287)	-	(2,671,287)
Customer Advances	(217,497)	-	(217,497)
Total Deductions	\$ (220,534,790)	\$ 1,520,945	\$ (219,013,845)
Total Rate Base	<u>\$ 996,093,941</u>	<u>\$ (63,058,366)</u>	<u>\$ 933,035,575</u>

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Adjustments to Rate Base
Rate Year Ended June 30, 2014

	<u>Amount</u>	<u>Source</u>
Rate Base per Company Filing	\$ 996,093,941	Exhibit No. NJDK-3R
<u>OCA Adjustments</u>		
Average Rate Year Plant	(65,400,755)	Schedule TSC-5S
Additional Capital Spending	<u>2,342,389</u>	Schedule TSC-18S
Total OCA Adjustments	<u>\$ (63,058,366)</u>	
OCA Adjusted Rate Base	<u><u>\$ 933,035,575</u></u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Adjustments to Operating Income
Rate Year Ended June 30, 2014

	<u>Amount</u>	<u>Source</u>
Income Before Income Taxes per Company	\$ 48,519,736	Ex. JTG-R2, Schedule 4
<u>OCA Adjustments</u>		
Rate Year Salaries and Wage Expense-Existing Employees	389,465	Schedule TSC-6S
Rate Year Salaries and Wage Expense-New Employees	15,101	Schedule TSC-7S
Pension and Benefits Expense	2,760,455	Schedule TSC-8S
NCSC Labor and Related Billings	740,429	Schedule TSC-9S
Profit Sharing Expense	331,194	Schedule TSC-10S
Phantom Stock Expense	101,981	Schedule TSC-11S
Corporate Insurance	-	Schedule TSC-12S
Deferred NiFit O&M Amortization	505,000	Schedule TSC-13S
GEAC Support and Maintenance	-	Schedule TSC-14S
Longwall Mining Amortization	(13,552)	Schedule TSC-15S
Lease Expense	-	See Note (1)
Depreciation on Average Rate Year Plant	1,536,473	Schedule TSC-16S
FICA Taxes	30,741	Schedule TSC-17S
Depreciation on Additional Capital Spend	<u>(52,767)</u>	Schedule TSC-18S
Total OCA Adjustments to Income before Taxes	\$ 6,344,521	
OCA Adjusted Income Before Income Taxes	<u>\$ 54,864,257</u>	

Note:

(1) Columbia reflected correction on Exhibit JTG-R2, Schedule 1, page 1.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Adjustments to Operating Income before Income Taxes
Rate Year Ended June 30, 2014

	<u>Revenue</u>	<u>O&M</u>	<u>Depreciation</u>	<u>Taxes Other Than Income</u>	<u>Operating Income Before Taxes</u>
Operating Income per Company	\$ 379,668,673	\$ 286,105,479	\$ 41,399,613	\$ 3,643,845	\$ 48,519,736
<u>OCA Adjustments</u>					
Rate Year Salaries and Wage Expense-Existing Employees		(389,465)			389,465
Rate Year Salaries and Wage Expense-New Employees		(15,101)			15,101
Pension and Benefits Expense		(2,760,455)			2,760,455
NCSC Labor and Related Billings		(740,429)			740,429
Profit Sharing Expense		(331,194)			331,194
Phantom Stock Expense		(101,981)			101,981
Corporate Insurance		-			-
Deferred NiFit O&M Amortization		(505,000)			505,000
GEAC Support and Maintenance		-			-
Longwall Mining Amortization		13,552			(13,552)
Lease Expense					-
Depreciation on Average Rate Year Plant			(1,536,473)		1,536,473
FICA Taxes				(30,741)	30,741
Depreciation on Additional Capital Spend	-	-	52,767	-	(52,767)
Total OCA Adjustments	\$ -	\$ (4,830,073)	\$ (1,483,706)	\$ (30,741)	\$ 6,344,521
OCA Adjusted Income Before Income Taxes	\$ 379,668,673	\$ 281,275,406	\$ 39,915,907	\$ 3,613,104	\$ 54,864,257

COLUMBIA GAS OF PENNSYLVANIA, INC.

Income Tax Reconciliation
Rate Year Ended June 30, 2014

	Amount per Company at Present Rates	OCA Adjustments	Adjusted Per OCA at Present Rates	Proposed Revenue Increase	Amount at Proposed Rates
Operating Income before Taxes	\$ 48,519,736	\$ 6,344,521	\$ 54,864,257	\$ 42,184,332	\$ 97,048,589
Interest Expense	(26,197,271)	2,031,649	(24,165,621)	-	(24,165,621)
Other Flow-Through Adjustments	8,553,745	-	8,553,745	-	8,553,745
Deferral Adjustments	(48,101,814)	-	(48,101,814)	-	(48,101,814)
Total Statutory Adjustments	\$ (65,745,340)	\$ 2,031,649	\$ (63,713,690)	\$ -	\$ (63,713,690)
Taxable Income Subtotal	\$ (17,225,604)	\$ 8,376,170	\$ (8,849,434)	\$ 42,184,332	\$ 33,334,898
Pennsylvania Bonus Depreciation	19,051,448	-	19,051,448	-	19,051,448
State Taxable Income	\$ 1,825,844	\$ 8,376,170	\$ 10,202,014	\$ 42,184,332	\$ 52,386,346
Net Operating Loss Deduction	3,000,000	-	3,000,000	7,477,269	10,477,269
Adjusted State Taxable Income	\$ (1,174,156)	\$ 8,376,170	\$ 7,202,014	\$ 34,707,063	\$ 41,909,077
Pennsylvania Income Tax at 9.99%	\$ (117,298)	\$ 836,779	\$ 719,481	\$ 3,467,236	\$ 4,186,717
Deferred State Income Taxes	1,566,210	-	1,566,210	-	1,566,210
Total State Income Taxes	\$ 1,448,912	\$ 836,779	\$ 2,285,691	\$ 3,467,236	\$ 5,752,927
Taxable Income Subtotal	(17,108,305)	7,539,391	(9,568,915)	38,717,097	29,148,182
Federal NOL Adjustment	-	-	-	-	-
Current Federal Taxable Income	\$ (17,108,305)	\$ 7,539,391	\$ (9,568,915)	\$ 38,717,097	\$ 29,148,182
Current Federal Income Tax	(5,987,907)	2,638,787	(3,349,120)	13,550,984	10,201,864
Deferred Federal Income Tax	16,835,635	-	16,835,635	-	16,835,635
Tax Refund Amortization	(4,089,420)	-	(4,089,420)	-	(4,089,420)
Flow Back of Excess Deferred Taxes	(628,368)	-	(628,368)	-	(628,368)
Effect of CNIT Deferred on Federal	(548,174)	-	(548,174)	-	(548,174)
Total Federal Income Taxes	\$ 5,581,766	\$ 2,638,787	\$ 8,220,553	\$ 13,550,984	\$ 21,771,537
			\$ 10,506,244		
<u>Calculation of Interest Deduction</u>					
Rate Base	\$ 996,093,941		\$ 933,035,575		\$ 933,035,575
Weighted Cost of Debt	2.63%		2.59%		2.59%
Interest Deduction	\$ 26,197,271	\$ (2,031,649)	\$ 24,165,621		\$ 24,165,621
State Income Tax Effect at 9.99%		202,962			
Federal Income Tax Effect at 35%		640,041			
Interest Synchronization Adjustment		\$ 843,002			

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Rate Base to Reflect
13-Month Average Balances of Plant and Related Items
Rate Year Ended June 30, 2014

	June 30, 2014 Balance per Company (1)	13-Month Avg. Balance per OCA	Adjustment
Plant In Service (2)	\$ 1,477,108,215	1,401,796,427	(75,311,788)
Accumulated Depreciation (3)	<u>(340,952,106)</u>	<u>(332,619,579)</u>	<u>8,332,527</u>
Net Utility Plant	\$ 1,136,156,109	\$ 1,069,176,849	\$ (66,979,260)
Accumulated Deferred Income Taxes (4)	<u>(218,090,405)</u>	<u>(216,511,899)</u>	<u>1,578,506</u>
Net Balance	<u>\$ 918,065,704</u>	<u>\$ 852,664,949</u>	<u>\$ (65,400,755)</u>

Notes:

- (1) Amount per Exhibit No. 108, page 3.
- (2) OCA amounts per Exhibit No. 108, Schedule 1.
- (3) OCA amount is pending response to data request.
- (4) OCA Amount per response to I&E-RE-135-D.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Rate Year Salaries and Wages
for Existing Employees as of 5/31/2012
Rate Year Ended June 30, 2014

	<u>Amount</u>
Annualized Rate Year Wage Increase for Existing Employees (1)	\$ 1,133,539
Increases Paid during 12 Months Ending 6/30/2014 (2)	<u>544,868</u>
Adjustment to Rate Year Wages	\$ (588,671)
Percent to O&M (3)	<u>66.16%</u>
Adjustment to Rate Year Labor	<u><u>\$ (389,465)</u></u>

Notes:

- (1) Per Exhibit JTG-R2, Schedule 1, page 5.
- (2) Calculated based Exhibit JTG-R2, Schedule 1, page 5.
- (3) Per Exhibit JTG-R2, Schedule 1, page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Rate Year Salaries and Wages
for New Employees added after 5/31/2012
Rate Year Ended June 30, 2014

	<u>Amount</u>
Annualized Rate Year Wage Increase for New Employees (1)	\$ 33,188
Increases Paid during 12 Months Ending 6/30/2014 (2)	<u>18,087</u>
Adjustment to Rate Year Labor	<u>\$ (15,101)</u>

Notes:

(1) Per Exhibit JTG-R1. Reflects amount charged to O&M.

(2) Calculated based on Exhibit JTG-R1. Includes full June 2013 increase and one month of June 2014 increase

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Pension & Benefits Expense
to Reflect Rate Year Amounts
Rate Year Ended June 30, 2014

	2013 Gross Cost (1)	2014 Gross Cost (2)	Rate Year Gross Cost	Percent to O&M (3)	Rate Year Expense	Cost for New Employees 34.49% To O&M (4)	Adjusted Expense Per OCA	2014 Expense per Company (2)	Adjustment to Rate Year Expense
PENSION AND RETIREMENT INCOME PLANS									
Retirement Income Plan (5)	\$ -	\$ 3,249,000	\$ 1,624,500	66.16%	1,074,769	N/A	\$ 1,074,769	\$ 3,670,667	(2,595,898)
Supplemental Retirement Income Plan	3,000	5,000	4,000	66.16%	2,646	N/A	2,646	3,317	(671)
Total Pensions and Retirement Income	\$ 3,000	\$ 3,254,000	\$ 1,628,500		\$ 1,077,416	\$ -	\$ 1,077,416	\$ 3,673,984	\$(2,596,568)
OPEB COST									
Ongoing OPEB - Medical	-	-	-	66.16%	-	N/A	-	-	-
Ongoing OPEB - Group Life	-	-	-	66.16%	-	N/A	-	-	-
SFAS 106 Amortization	-	-	-	66.16%	-	N/A	-	-	-
Total SFAS 106 Cost	\$ -	\$ -	\$ -		\$ -	\$ -	\$ -	\$ -	\$ -
SFAS 112	138,824	138,824	138,824	100.00%	138,824	N/A	138,824	138,824	-
OPEB difference between expense and recovery	-	-	-	100.00%	-	N/A	-	0	-
OPEB Overcollection Post Rate Case	(303,697)	(303,697)	(303,697)	100.00%	(303,697)	N/A	(303,697)	(303,697)	-
Total SFAS 112 Costs	\$ (164,873)	\$ (164,873)	(164,873)		\$ (164,873)	\$ -	\$ (164,873)	\$ (164,873)	\$ -
EMPLOYEES' INSURANCE PLANS & OTHER									
Comp Medical Insurance and EAP	4,201,000	4,583,000	4,392,000	66.16%	2,905,747	163,361	3,069,108	3,202,590	(133,482)
Dental Assistance	309,000	323,000	316,000	66.16%	209,066	11,754	220,819	225,712	(4,893)
Group Life Insurance	114,000	118,000	116,000	66.16%	76,746	4,315	81,060	82,458	(1,398)
Long Term Disability	289,000	298,000	293,500	66.16%	194,180	10,917	205,096	208,242	(3,146)
Total Employees' Insurance Plans	\$ 4,913,000	\$ 5,322,000	\$ 5,117,500	66.16%	\$ 3,385,738	\$ 190,346	\$ 3,576,084	\$ 3,719,002	\$ (142,918)
Thrift Plan	1,727,000	1,778,000	1,752,500	66.16%	1,159,454	\$ 65,184	1,224,638	1,242,462	(17,824)
Profit Sharing	315,000	324,000	319,500	66.16%	211,381	11,884	223,265	226,410	(3,145)
Inter-Company Billing	112,071	112,071	112,071	66.16%	74,146	-	74,146	74,146	0
Total Employees' Insurance Plans and Other	\$ 7,067,071	\$ 7,536,071	\$ 7,301,571		\$ 4,830,719	\$ 267,414	\$ 5,098,134	\$ 5,262,020	\$ (163,886)
Total Pension and Benefits	\$ 6,905,198	\$ 10,625,198	\$ 8,765,198		\$ 5,743,262	\$ 267,414	\$ 6,010,676	\$ 8,771,131	<u>\$(2,760,455)</u>

Notes:

(1) Per Exhibit No. 104, Schedule 2, page 11, except where noted.

(2) Per Exhibit No. 104, Schedule 2, page 12, except where noted.

(3) Reflects average percentage for 2008-2012 per Exhibit JTG-R2, Schedule 1, page 2.

(4) Reflects Rate Year Gross Cost divided by 510 existing employees times 55 new employees time percent to O&M for new employees per supplemental response to Exhibit JTG-R2.

(5) Retirement income plan amounts per response to I&E-RE-59-D.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to NCSC Labor and Related Billings
Rate Year Ended June 30, 2014

Total Rate Year NCSC Labor and Related Billings (1)	\$ 18,913,751
Percent Allocated to Columbia per OCA (2)	11.00%
Percent Allocated to Columbia per Company (3)	11.22%
Adjusted Rate Year NCSC Labor and Related Billings	<u>\$ 18,542,893</u>
Adjustment to Rate Year Expense To Reflect Average Allocator	<u>\$ (370,858)</u>
Projected Rate Year New Headcount Labor per Company (4)	\$ 298,813
New Headcount Employee Expenses (4)	34,421
New Headcount Labor Restated for Change in Allocators	<u>\$ 333,234</u>
Costs to be incurred during the 12 Months Ended June 30, 2014 (4)	<u>\$ 254,094</u>
Adjustment to Reflect New Headcount based on Columbia Allocator	<u>\$ (79,140)</u>
Ratio of Labor Allocators (4)	<u>98.04%</u>
Adjustment to Reflect New Headcount Costs during Rate Year	<u>\$ (77,588)</u>
Differences between Rate Year Cost and Annualized End of Rate Year Cost (5)	\$ (297,823)
Ratio of Labor Allocators (4)	98.04%
	98.04%
Adjustment to Reflect Annual Labor and Related Expense during Rate Year	<u>\$ (291,983)</u>
Total Adjustment to NCSC Labor and Related Billings	<u>\$ (740,429)</u>

Notes:

- (1) Per Exhibit No. 104, Schedule No. 2, page 27.
- (2) Reflects percentage for the 12 months ending December 31, 2012.
- (3) Reflects percentage for May 2012 per Exhibit No. 4, Schedule 2, page 23.
- (4) Per Exhibit No. 104, Schedule No. 2, page 31.
- (5) Refer to page 2 of this schedule.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Calculation of Difference Between
Rate Year Expense and Annualized End of Rate Year
for NCSC Labor and Related Costs
Rate Year Ended June 30, 2014

	2014 Annualized Amount Per Company	Rate Year Amount Per OCA	Rate Year vs. Annualized Difference (4)
2014 Payroll and Benefit Increase (1)	\$ 439,904	\$ 146,500	\$ (293,404)
Incentive Compensation (2)	104,137	52,068	(52,069)
Pension (3)	<u>(95,300)</u>	<u>(47,650)</u>	<u>47,650</u>
Total	\$ 448,741	\$ 150,918	\$ (297,823)

Notes:

(1) Per Exhibit No. 104, Schedule 2, page 29.

(2) Per Exhibit No. 104, Schedule 2, page 28.

(3) Per response to I&E-RE-11-D.

(4) Reflects differences before accounting for OCA Adjustment to percentage allocation to Columbia.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Profit Sharing Expense
Rate Year Ended June 30, 2014

<u>Profit Sharing Plan Expense</u>	<u>Amount</u>
Company Employees (1)	\$ 223,265
NCSC Charges (2)	<u>107,929</u>
Adjustment to Eliminate Profit Sharing Plan Expense	<u>\$ (331,194)</u>

Notes:

- (1) Per Exhibit No. 104, Schedule 2, Page 12, as adjusted on Schedule TSC-8
- (2) Reflects amount per response to OCA I-12 of \$112,683 adjusted to exclude one-half of the rate year increase of \$5,190 and to reflect the average annual allocation to Columbia rather than the May 2012 allocation as discussed with regard to the adjustment to NCSC labor costs shown on Schedule TSC-9.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Phantom Stock Expense
Rate Year Ended June 30, 2014

	<u>Amount</u>
Phantom Stock Expense per Company (1)	\$ 101,981
Allowable Expense per OCA	<u>-</u>
Adjustment to Eliminate Phantom Stock Expense	<u>\$ (101,981)</u>

Note:

(1) Per response to OCA 1-12.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Corporate Insurance Expense
Rate Year Ended June 30, 2014

	Premiums for the 12 Months Ending 6/30/2013 (1) (A)	Premiums for the 12 Months Ending 6/30/2014 (2) (B)=(A) x 1.56%	Amount per Company (3) (C)	Adjustment
Property Insurance	\$ 245,075	\$ 248,898	\$ 248,898	\$ -
Other Liability Insurance	2,124,029	2,157,164	2,157,164	-
Workers Compensation	547,982	556,531	556,531	-
Total Corporate Insurance Premiums	\$ 2,917,086	\$ 2,962,593	\$ 2,962,593	\$ -
Workers Compensation Tranferred to Capital (4)	(185,437)	(185,437)	(181,040)	(4,397)
Total Corporate Insurance Expenses (5)	\$ 2,731,649	\$ 2,777,155	\$ 2,781,553	\$ -

Notes:

- (1) Per response to OCA VI-4 and Exhibit No. 104, Schedule 2, page 16.
- (2) Column A times increase in the GDP Deflator per Exhibit No. 104, Schedule 2, page 21.
- (3) Per Exhibit No. 104, Schedule 2, page 16 and Exhibit JTG-R2, Schedule 1, page 1
- (4) Amounts in columns (A) and (B) reflect updated percent capitalized per Schedule TSC-6.
- (5) Columbia did not adjust amount capitalized for revised 5 year average. Di minimus adjustment has been ignored.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Deferred NiFit Cost Amortization
Rate Year Ended June 30, 2014

	<u>Amount</u>
Deferred NiFit Costs (1)	\$ 2,020,000
OCA Proposed Amortization Period	<u>4 Years</u>
Annual Amortization Expense per OCA	\$ 505,000
Annual Amortization Expense per Company (2)	<u>1,010,000</u>
Adjustment to NiFit Amortization Expense	<u>\$ (505,000)</u>

Notes:

(1) Per Direct Testimony of Columbia witnesses Richard Fontaine and Jeffery T. Gore.

(2) Per Exhibit No. JTG-2, Schedule 1, page 1.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Eliminate GEAC Financial Software Costs
Rate Year Ended June 30, 2014

	<u>Amount</u>
GEAC Support and Maintenance Costs in HTY (1)	\$ 45,359
Inflation Factor for HTY to FTY (2)	1.0185
Inflation Factor for FTY to FFRY (3)	<u>1.0156</u>
Adjustment to Eliminate GEAC Support and Maintenance Costs (4)	<u>\$ -</u>

Notes:

- (1) Per response to OCA II-5.
- (2) Per Exhibit No. 104, Schedule 2, page 22.
- (3) Per Exhibit No. 104, Schedule 2, page 27.
- (4) Company claim has been accepted.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Longwall Mining Costs
Rate Year Ended June 30, 2014

	<u>Amount</u>
Longwall Mining Costs in FFRY per Company (1)	\$ -
Rate Year Amortization of Remaining Balance at 6/30/2013 (2)	<u>13,552</u>
Adjustment to Longwall Mining Costs	<u><u>\$ 13,552</u></u>

Notes:

(1) Per Exhibit JTG-R2, Schedule 1, page 1

(2) Per response to I&E-RE-133.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Depreciation Expense
Rate Year Ended June 30, 2014

	<u>Amount</u>
13 Month Average Balance of Plant in Service (1)	\$ 1,401,796,427
Less: 13 Month Average of Amortization and Non-Depreciable Plant (2)	<u>(12,749,406)</u>
13 Month Average Balance of Depreciable Plant in Service	\$ 1,389,047,021
Composite Depreciation Rate (3)	<u>2.3801%</u>
Depreciation Expense	\$ 33,060,372.92
Amortization Expense (4)	<u>1,938,436</u>
Rate Year Depreciation and Amortization per OCA	\$ 34,998,809
Rate Year Depreciation and Amortization as of 6/30/2014 per Company (5)	<u>\$ 36,535,282</u>
Adjustment to Depreciation Expense (6)	<u><u>\$ (1,536,473)</u></u>

Notes:

- (1) Per Schedule TSC-5.
- (2) Per Exhibit No. 108, Schedule 1. Reflects Accounts 303, 374.2, 375.71, and non-depreciable plant consistent with Exhibit No. 105.
- (3) Based on depreciation expense divided by depreciable plant per Exhibit No. 105, pages 7-10.
- (4) Reflects amortization at 6/30/2014.
- (5) Per Exhibit JTG-R2, Schedule 4, page 1 of 5.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to FICA Tax Expense
Rate Year Ended June 30, 2014

	<u>Taxable for Social Security</u>	<u>Taxable for Medicare</u>
Adjustment to Labor Expense for Existing Employees (1)	\$ (389,465)	\$ (389,465)
Adjustment to Labor Expense for New Employees (2)	<u>(15,101)</u>	<u>(15,101)</u>
OCA Adjustment to Labor Expense	\$ (404,566)	\$ (404,566)
Percent Taxable (3)	<u>99.17%</u>	<u>100.00%</u>
Taxable Base	\$ (401,208)	\$ (404,566)
Tax Rate	<u>6.20%</u>	<u>1.45%</u>
Total Tax Amount	\$ (24,875)	\$ (5,866)
Adjustment to FICA Tax Expense for OCA Wage Adjustments		<u><u>\$ (30,741)</u></u>

Notes:

- (1) Per Schedule TSC-6.
- (2) Per Schedule TSC-7.
- (3) Per response to I&E-RE-128.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Adjustment to Include Investment and Depreciation
Associated with \$3.2 Million Additional Capital Spending
Rate Year Ended June 30, 2014

	13-Month Avg. Balance per OCA
Plant In Service (1)	2,420,923
Accumulated Depreciation (1)	(20,973)
Net Utility Plant	\$ 2,399,950
Accumulated Deferred Income Taxes (2)	(57,561)
Increase in Rate Base	\$ 2,342,389
Rate Year Depreciation Expense (3)	\$ 52,767

Notes:

- (1) Based on monthly balances per Exhibit JTG-R2, Schedule 5, page 2.
- (2) Calculated based on IRS Regs. Section 1.167 method using end of end of year balance per Exhibit JTG-R2, Schedule 5, page 2.
- (3) Rate year accruals per Exhibit JTG-R2, Schedule 5, page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Cost of Capital
Rate Year Ended June 30, 2014

Per Company

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short-Term Debt	3.57%	1.90%	0.07%
Long-Term Debt	44.11%	5.80%	2.56%
Common Equity	52.32%	11.25%	5.89%
Total	100.00%		8.52%

Per OCA

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short-Term Debt	3.63%	1.57%	0.06%
Long-Term Debt	44.79%	5.64%	2.53%
Common Equity	51.58%	9.50%	4.90%
Total	100.00%		7.49%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

**PENNSYLVANIA PUBLIC UTILITY
COMMISSION**

V.

COLUMBIA GAS OF PENNSYLVANIA, INC.

**DOCKET NOS. R-2012-2321748
M-2012-2323645**

DIRECT TESTIMONY

OF

MATTHEW I. KAHAL

**ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE**

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EXETER

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

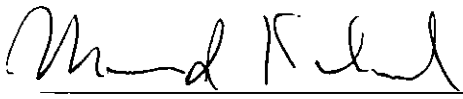
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2012-2321748
	:	M-2012-2323645
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, MATTHEW I. KAHAL, hereby state that the facts above set forth in my Direct Testimony (OCA Statement No. 2) and Surrebuttal Testimony (OCA Statement 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: 
MATTHEW I. KAHAL

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

DATED: February 8, 2013

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APPENDIX A	

1 **I. QUALIFICATIONS**

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A. My name is Matthew I. Kahal. I am employed as an independent consultant retained
4 in this matter by the Office of Consumer Advocate (OCA). My business address is
5 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

6 Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

7 A. I hold B.A. and M.A. degrees in economics from the University of Maryland and
8 have completed course work and examination requirements for the Ph.D. degree in
9 economics. My areas of academic concentration included industrial organization,
10 economic development and econometrics.

11 Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

12 A. I have been employed in the area of energy, utility and telecommunications
13 consulting for the past 30 years, working on a wide range of topics. Most of my work
14 has focused on electric utility integrated planning, plant licensing, environmental
15 issues, mergers and financial issues. I was a co-founder of Exeter Associates, and
16 from 1981 to 2001, I was employed at Exeter Associates as a Senior Economist and
17 Principal. During that time, I took the lead role at Exeter in performing cost of capital
18 and financial studies.

19 Prior to entering consulting, I served on the Economics Department faculties
20 at the University of Maryland (College Park) and Montgomery College teaching
21 courses on economic principles, development economics and business.

22 A complete description of my professional background is provided in
23 Appendix A.

1 Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS
2 BEFORE UTILITY REGULATORY COMMISSIONS?

3 A. Yes. I have testified before approximately two dozen state and federal utility
4 commissions and federal court in more than 380 separate regulatory cases. My
5 testimony has addressed a variety of subjects including fair rate of return, resource
6 planning, financial assessments, load forecasting, competitive restructuring, rate
7 design, purchased power contracts, merger economics and other regulatory policy
8 issues. These cases have involved electric, gas, water and telephone utilities. In 1989,
9 I testified before the U. S. House of Representatives, Committee on Ways and Means,
10 on proposed federal tax legislation affecting utilities. A list of these cases may be
11 found in Appendix A, with my statement of qualifications.

12 Q. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE
13 LEAVING EXETER AS A PRINCIPAL IN 2001?

14 A. Since 2001, I have worked on a variety of consulting assignments pertaining to
15 electric restructuring, purchase power contracts, environmental controls, cost of
16 capital and other regulatory issues. Current and recent clients include the U.S.
17 Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal
18 Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office
19 of Consumer Advocate, New Jersey Division of Rate Counsel, Rhode Island Division
20 of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service
21 Commission, the Maine Public Advocate, Maryland Department of Natural
22 Resources and Energy Administration, and MCI.

23 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

24 A. Yes. I have testified on cost of capital and other matters before the Pennsylvania
25 Public Utility Commission ("PAPUC" or "the Commission") in natural gas, water,

1 telecom and electric cases during the past 30 years. In addition to fair rate of return in
2 rate proceedings, I have also testified before this Commission in merger cases,
3 electric restructuring and default service cases. In all cases, my testimony was
4 submitted on behalf of the OCA. A listing of all such cases is provided in Appendix
5 A accompanying my testimony.

II. OVERVIEW

1 **A. Summary of Recommendation**

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

4 A. I have been asked by the OCA in this case to develop a recommendation concerning
5 the fair rate of return on the gas utility rate base of Columbia Gas of Pennsylvania,
6 Inc. ("CPA" or "the Company"). This includes both a review of the Company's
7 proposal concerning rate of return and the preparation of an independent study of the
8 cost of common equity. I am providing my recommendation to the OCA's revenue
9 requirement consultant, Mr. Catlin, for use in calculating the Company's annual
10 revenue requirement in this case.

11 Q. WHAT IS THE COMPANY'S RATE OF RETURN PROPOSAL IN THIS
12 CASE?

13 A. As presented on Company Exhibit 400, Schedule 1, page 1 of 1, the Company
14 requests an authorized overall rate of return of 8.52 percent. The proposed capital
15 structure is indicated as being the Company's projected capital structure at
16 June 30, 2014, the end of the fully forecasted rate year. It includes 52.32 percent
17 common equity, 44.11 percent long-term debt and 3.57 percent short-term debt. This
18 capital structure is generally similar to the average capital structure of the gas
19 distribution industry proxy group used by the Company in this case (i.e.,
20 approximately 51 percent equity and 49 percent debt as of 2011), and it includes
21 recognition of the Company's projected short-term debt on a 12-month average basis.
22 The Company requests a return on the common equity component of 11.25 percent.
23 The overall rate of return, capital structure and cost of debt and equity
24 recommendations are sponsored by the Company's witness, Mr. Paul Moul, the

1 Company's consultant on cost of capital. Mr. Moul's 11.25 percent return on equity
2 ("ROE") recommendation is based on the results of his various studies, which he
3 characterizes as ranging from 11.0 to 11.3 percent, and it also includes a 10 basis
4 point (0.1%) bonus for "outstanding performance." Absent this proposed bonus, Mr.
5 Moul presumably would be supporting a cost of equity capital award of 11.15
6 percent.

7 Q. WHAT IS CPA'S CORPORATE STRUCTURE?

8 A. CPA is a wholly-owned subsidiary of Columbia Energy Group ("CEG"), which itself
9 is owned by NiSource, Inc. NiSource is a diversified and publically-traded energy
10 company with three main business segments: (a) vertically-integrated electric utility;
11 (b) gas utility distribution; and (c) interstate gas transmission and storage. As
12 discussed in more detail later in my testimony, CPA is fully financially integrated
13 with NiSource and depends on the ultimate parent for both its debt and equity capital.

14 Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME ON RATE OF
15 RETURN?

16 A. As summarized on Schedule MIK-1, page 1 of 1, I am recommending at this time a
17 return on CPA's jurisdictional gas utility rate base of 7.49 percent. This includes a
18 return on common equity of 9.5 percent and a capital structure of 48.4 percent total
19 debt and 51.6 percent common equity. This capital structure recommendation is
20 similar to that proposed by the Company, with slightly less equity at June 30, 2014
21 than projected by the Company. It includes the Company's statement of its claimed
22 and planned long-term debt at June 30, 2014, as well as its projected 12-month
23 average balance of short-term debt. In projecting the equity balance, I believe Mr.
24 Moul may have used assumptions of retained earnings growth that are too optimistic.

1 The development of my recommended capital structure and embedded cost of debt is
2 discussed in Section III of my testimony.

3 Please note that my 9.5 percent return on equity recommendation is based on
4 the assumption that the Commission does not adopt the Company's proposals
5 concerning residential rate design, changes to rate design that the OCA is not
6 supporting in this case. The rate design alternatives proposed at this time by CPA
7 include (a) the Levelized Distribution charge; (b) the Revenue Normalization
8 Adjustment; and (c) a Weather Normalization Adjustment. All three alternatives are
9 intended to provide CPA with greater revenue certainty. In the event the Commission
10 adopts any of these risk-reducing rate design changes, my recommended return on
11 equity would be 9.3 percent, i.e., the midpoint of my proxy group range. My
12 recommendation recognizes that CPA now has available two important new risk-
13 reducing features, those being the Distribution System Improvement Charge (DSIC)
14 and the use of a fully forecasted future rate year in base rate cases.

15 Q. WHAT IS YOUR COST OF DEBT RECOMMENDATION?

16 A. I am recommending at this time a long-term embedded cost of debt of 5.64 percent,
17 which is slightly less than the 5.80 percent recommended by witness Moul on behalf
18 of the Company. I am using the same 1.57 percent cost of short-term debt as
19 identified by Mr. Moul as being CPA's current cost of short-term debt, but I do not
20 accept his recommendation to increase that cost rate figure to 1.90 percent at the end
21 of the fully forecasted rate year. This small reduction in the cost of long-term debt
22 that I am recommending (i.e., 5.80 versus 5.64 percent) is the result of differing
23 assumptions concerning the cost that the Company will (or should) incur in issuing
24 new long-term debt.

1 Q. HOW DOES MR. MOUL DEVELOP HIS 11.25 PERCENT ROE
2 RECOMMENDATION?

3 A. Mr. Moul utilizes three cost of equity methods: (1) Discounted Cash Flow (DCF);
4 (2) the Risk Premium; and (3) Capital Asset Pricing Model (CAPM), with each
5 methodology (or at least the DCF and CAPM methods) applied to a proxy group of
6 nine publically-traded gas utility companies. The results of these three studies (with
7 his adjustments) average to about 10.9 percent. He also conducts a "comparable
8 earnings" study of non-regulated companies and obtains a somewhat higher result of
9 12.70 percent. This study merely measures accounting profits, and therefore, is not a
10 cost of equity study. It appears from the discussion in his testimony that the
11 comparable earnings result does play some role in formulating his ROE
12 recommendation.

13 Finally, Mr. Moul adds a Company performance bonus of 0.10 percent to his
14 CPA baseline cost of equity midpoint of 11.15 percent. This produces his ROE
15 award recommendation of 11.25 percent.

16 Q. HOW HAVE YOU DEVELOPED YOUR 9.5 PERCENT ROE
17 RECOMMENDATION?

18 A. I rely primarily on the use of the DCF model as applied to a gas distribution utility
19 proxy group that is identical to the group used by Mr. Moul. This produces a cost of
20 equity range of 8.8 to 9.8 percent, with a midpoint of 9.3 percent. My
21 recommendation considers the need for a risk adjustment for CPA as compared to the
22 gas utility proxy group, resulting in a recommendation of 9.5 percent. This risk
23 adjustment is to recognize that some of the Gas Group proxy companies used by both
24 Mr. Moul and myself are permitted to use one of the rate design alternatives proposed
25 by CPA that the OCA does not support in this case. Given the currently available

1 cost of capital evidence, I find that 9.5 percent is a conservatively high
2 recommendation. Moreover, the 9.5 percent (as opposed to the 9.3 percent DCF
3 midpoint) would be an appropriate ROE award only if the OCA's position on
4 residential rate design is adopted. As a check, I have prepared a CAPM study, which
5 produced a cost of equity range of 6.1 to 8.7 percent, although I would tend to place
6 greater emphasis on the upper end of this range. I believe that far greater reliance
7 should be placed on the DCF studies, as the CAPM results are more uncertain and
8 less reliable than those obtained from the DCF method. Moreover, my understanding
9 is that this Commission relies primarily on the DCF method.

10 In my opinion, these cost of equity study results, taking into account the
11 recent financial market instability, support the reasonableness of my 9.5 percent
12 return on equity recommendation for CPA at this time.

13 Q. PLEASE EXPLAIN THE ASSERTED NEED FOR A RISK ADJUSTMENT.

14 A. Mr. Moul claims that CPA is riskier than the gas utility proxy group as evidenced by
15 its parent company's relatively weak BBB- credit rating. This is the basis for his 0.76
16 percent risk adjustment adder. Mr. Moul also mentions other qualitative and
17 quantitative factors such as regional gas-on-gas competition and large capital
18 requirements as reasons supporting the risk adjustment he proposes.

19 Section III.B. of my testimony explains why I believe Mr. Moul has
20 overstated the need for a risk adjustment and why his quantification is far too large.
21 Nonetheless, I believe that a more modest risk adjustment to the proxy group cost of
22 equity should be considered for CPA, a range of zero to 0.4 percent, or a midpoint
23 risk adder of 0.2 percent. This is included in my final recommendation of 9.5
24 percent.

1 I further note that the Company has recommended alternative residential rate
2 design changes that are intended to reduce its business risk associated with serving
3 the residential class and thereby shifting operational risks from shareholders to
4 customers. If any such changes are approved in this case, then any risk adder to the
5 DCF proxy group cost of equity midpoint would be inappropriate. In such a case, my
6 final ROE recommendation would be the proxy group DCF midpoint of 9.3 percent.
7 In other words, my 9.5 percent recommendation shown on Schedule MIK-1 is based
8 on the assumption that the OCA position on residential rate design is adopted in this
9 case.

10 Q. YOUR ROE RECOMMENDATION DIFFERS FROM THAT OF MR.
11 MOUL. HOW DO YOU ACCOUNT FOR THE DIFFERENCE?

12 A. I believe that the primary difference is that Mr. Moul has included extraneous
13 adjustment factors or "adders" in his DCF and CAPM studies that are not part of the
14 cost of equity for CPA. These include a "market-to-book" or "leverage" adjustment
15 that artificially raises his cost of equity estimate. This adjustment seeks to "correct"
16 for the fact that book value capitalization (rather than market value capitalization) is
17 used for setting the ratemaking capital structure, and it is intended to provide
18 additional investor compensation over and above the estimated market cost of equity.
19 In the CAPM study, Mr. Moul also introduces a "size" adjustment factor that
20 improperly inflates his ROE estimate by 1.14 percent. In addition, I do not support
21 his implied 0.10 percent management "bonus" recommendation (which also is not
22 part of the CPA cost of equity).

1 Q. DO YOU CONSIDER CPA TO HAVE FAVORABLE BUSINESS RISK
2 CHARACTERISTICS?

3 A. Yes, very much so. CPA provides gas distribution utility service in its Pennsylvania
4 service territory, subject to the regulatory oversight of the Commission. There is no
5 indication of any material increase in the Company's business in recent years. While
6 the Company's business risk profile presently is very favorable, in the future it will
7 have the opportunity to implement a DSIC, which can further strengthen its business
8 risk and financial risk profiles by making available an additional cost recovery
9 mechanism. In addition, the Company is also permitted to employ a fully forecasted
10 rate year in its base rate cases. In Section III of my testimony, I discuss the business
11 risk attributes for the Company and why Mr. Moul's cost of equity risk adjustment is
12 improper.

13 Q. HAVE YOU INCLUDED A BONUS OR ADDER IN YOUR
14 RECOMMENDED ROE FOR CPA MANAGEMENT PERFORMANCE?

15 A. No. I have not conducted an evaluation of CPA's management performance or
16 service quality, as that topic is beyond the scope of my testimony. Moreover, it
17 appears that Mr. Moul also has not conducted such an evaluation and instead is
18 relying on Company witnesses such as Mr. Kempic.

19 There are several reasons why burdening CPA customers with an ROE bonus
20 at this time would not be appropriate, particularly within the context of my
21 recommendation. First, my ROE recommendation already incorporates an upward
22 risk adjustment for CPA as compared to the proxy group baseline cost of equity
23 capital (assuming the OCA's rate design position is adopted). The rationale for this
24 risk adjustment and the reasons why I believe Mr. Moul's risk adjustment is improper
25 are discussed in Section III.B. of my testimony. Mr. Moul's management bonus is *in*

1 *addition* to his already very large 76 basis point (0.76 percent) risk adjustment.

2 Second, there is no indication that Mr. Moul has undertaken any independent review
3 of management performance. Third, I am concerned that CPA is incurring higher
4 than necessary debt costs due to the financial policies of NiSource, its ultimate parent.
5 This has resulted in a relatively weak credit rating, and unfortunately, CPA's cost of
6 debt is priced based on that credit rating. CPA ratepayers are therefore, being asked
7 to support a cost of capital that is already unnecessarily high and is the result of
8 NiSource parent company financial policies.

9 **B. Capital Cost Trends**

10 Q. HAVE YOU EXAMINED GENERAL TRENDS IN CAPITAL COSTS IN
11 RECENT YEARS?

12 A. Yes. I show the capital cost trends since 2001, through calendar year 2011, on page 1
13 of Schedule MIK-2. Pages 2, 3 and 4 of that Schedule show monthly data for
14 January 2007 through November 2012. The indicators provided include the
15 annualized inflation rate (as measured by the Consumer Price Index), 10-year
16 Treasury yields, 3-month Treasury bill yields and Moody's single A yields on long-
17 term utility bonds. While there is some fluctuation, these data series show a general
18 declining trend in capital costs. For example, in the early part of this 10-year period,
19 utility bond yields averaged about 8 percent, with 10-year Treasury yields of
20 5 percent. By 2011, single A utility bond yields had fallen to an average of
21 5.1 percent, with 10-year Treasury yields declining to an average of 2.8 percent.
22 Within the past year, Treasury and utility long-term bond rates have declined even
23 further to near or below the lowest levels in decades.

24 For the past three years, short-term Treasury rates have been close to zero,
25 with three-month Treasury bills averaging about 0.1 percent. These extraordinarily

1 low rates (which are also reflected in non-Treasury debt instruments) are the result of
2 an intentional policy of the Federal Reserve Board of Governors (the Fed) to make
3 liquidity available to the U.S. economy and to promote economic activity. The Fed
4 has also sought to exert downward pressure on long-term interest rates through its
5 policy of "quantitative easing." Quantitative easing is a policy whereby the Fed
6 engages on an ongoing basis in the purchase of financial assets (such as Treasury
7 bonds or agency mortgage backed debt), both to support the market prices of financial
8 assets and to increase the U.S. money supply. The intent is to keep the cost of capital
9 low and make credit more abundant. Although that program ended this past summer,
10 the Fed announced in September 2012 a continuation of its near zero short-term
11 interest rate policy at least through 2015, and an indefinite continuation of
12 quantitative easing. In its December 12, 2012 meeting, the Fed indicated that its low
13 interest rate and accommodative policies would continue at least until a much lower
14 U.S. unemployment rate is achieved, which is expected to take several years. As a
15 result, interest rates have remained low and have trended down and, for at least an
16 extended period of time, this very low short- and long-term interest rate and cost of
17 capital environment is expected to continue.

18 Q. ARE THERE FORCES CONTRIBUTING TO LOW INTEREST RATES
19 OTHER THAN FED POLICY?

20 A. Yes. While the decline in short-term rates is largely attributable to Fed policy
21 decisions, the behavior of long-term rates reflects more fundamental economic forces
22 along with Fed policy. Factors that drive down long-term bond interest rates include
23 the ongoing weakness of the U.S. and global macro economy, the inflation outlook
24 and even international events. A weak economy (as we have at this time) exerts
25 downward pressure on interest rates and capital costs generally because the demand

1 for capital is low and inflationary pressures are lacking. While inflation measures can
2 fluctuate from month to month, long-term inflation rate expectations presently remain
3 quite low. Europe's Euro-zone continuing sovereign debt crisis likely contributes to
4 lower U.S. interest rates, as U.S. securities are valued as a relative "safe haven" for
5 global capital.

6 Q. DO LOW LONG-TERM INTEREST RATES IMPLY A LOW COST OF
7 EQUITY FOR UTILITIES?

8 A. In a very general sense and over time, that is normally the case, although the utility
9 cost of equity and cost of debt need not move together in lock step or necessarily in
10 the short run. The economic forces mentioned above that lead to lower interest rates
11 also tend to exert downward pressure on the utility cost of equity. After all, many
12 investors tend to view utility stocks and bonds as alternative investment vehicles for
13 portfolio allocation purposes, and in that sense utility stocks and long-term bonds are
14 related by market forces.

15 Q. ARE RELATIVE ECONOMIC WEAKNESS AND LOW INFLATION
16 EXPECTED TO CONTINUE?

17 A. Yes, that appears to be the case. I have consulted the latest "consensus" forecasts
18 published by *Blue Chip Economic Indicators* (Blue Chip), October 10, 2012 edition,
19 which is a survey compilation of approximately 40 major forecast organizations. The
20 "consensus" calls for real GDP growth of 2.1 percent in 2012 and 2.0 percent in 2013
21 and inflation (GDP deflator) of 1.8 percent in both 2012 and 2013. The October 2012
22 edition of Blue Chip also publishes a consensus 10-year inflation forecast of 2.1
23 percent per year; almost no change from the near term. Thus, both the near- and
24 long-term economic outlooks are for sluggish economic growth and low inflation,
25 implying low capital costs.

1 Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS?

2 A. As one would expect, equity markets have exhibited more volatility than bond
3 markets. Following the onset of the financial crisis about four years ago, stock
4 market indices plunged, reaching a bottom in March 2009. Since then, stock prices
5 recovered impressively and the major indexes have largely recovered to pre-crisis
6 levels. The market recovery continued through most of the first half of 2011, but it
7 then began to deteriorate in late July 2011 with the debt ceiling crisis. The second
8 half of 2011 was characterized by significant stock market losses, some recovery and
9 high volatility. The federal debt ceiling debate issue and the subsequent Standard &
10 Poors (S&P) downgrade of Treasury securities may have been initial triggering
11 events for the equity market turmoil during August and September 2011. The larger
12 fundamental concerns of investors, based on reporting by the financial press, include
13 the unraveling of the Euro-zone sovereign debt crisis (and its potential adverse impact
14 on the European banking system) and the expectations by investors of the potential
15 for further weakening in the U.S. economy (and to some extent, the global economy).
16 In the fourth quarter of 2011, the stock market recovered, and for calendar 2011
17 overall, the stock market was flat or provided only very modest returns for investors.
18 Overall, 2012 has been a generally positive year for the stock market.

19 The effects of these economic events on U.S. utilities (such as CPA),
20 however, are difficult to interpret. It would seem that the Euro-zone and global
21 economic issues would have little to do directly with U.S. gas distribution utilities
22 such as CPA. However, the recent behavior of markets may, in a general sense,
23 reflect heightened equity risk premiums. At the same time, the continuing economic
24 weakness tends to exert downward pressure on capital costs, interest rates and

1 inflation. Thus, despite the turmoil in financial markets, we remain in a generally low
2 capital cost environment for good quality utilities.

3 Q. HAVE YOU BEEN ABLE TO INCORPORATE THESE RECENT
4 CHANGES IN FINANCIAL MARKETS INTO YOUR COST OF CAPITAL
5 ANALYSIS IN THIS CASE?

6 A. Yes, to a large extent I have done so. As a general matter, gas utility stocks have
7 been reasonably stable through the first nine months of 2012, as my testimony
8 demonstrates. The observed 2011 overall stock market volatility was quite
9 significant, but it appears to be transitory. While these market events are notable,
10 there is no clear evidence that this recent European and U.S. equity market volatility
11 has adversely and significantly affected the utility cost of capital. Dividend yields for
12 utility companies (such as low-risk gas utility companies) have been reasonably
13 stable this year, and the utility long-term cost of debt is at a historic low. At this
14 point, I believe it is reasonable to rely on a 2012 six-month average of market data,
15 which has been my past practice. This use of market data over a recent six-month
16 period fully accounts for the observed equity market behavior and expectations for
17 equity markets going forward.

18 C. **Overview of Testimony**

19 Q. HOW HAVE YOU ORGANIZED THE REMAINDER OF YOUR
20 TESTIMONY?

21 A. Section III of my testimony presents my discussion of the capital structure and cost of
22 debt recommended in this case by the Company. Section IV presents my cost of
23 equity studies, which are based on the DCF method, with the application of the
24 CAPM providing a comparison and corroboration. Finally, Section V is my review

1 of Mr. Moul's cost of equity studies, risk adjustments and his 11.25 percent ROE
2 recommendation.
3

1 **III. CAPITAL STRUCTURE AND OVERALL RISK**

2 **A. Capital Structure and Cost of Debt**

3 Q. WHAT CAPITAL STRUCTURE IS THE COMPANY UTILIZING IN THIS
4 CASE?

5 A. The requested capital structure in this case is based on CPA's projected capitalization
6 data at June 30, 2014, the end of the fully forecasted future rate year. The projections
7 reflect new financings anticipated to occur by June 30, 2014, along with an amount of
8 short-term debt based on a projected average for the 12 months ending June 2014.

9 The development of the June 30, 2014 capitalization is shown on Mr. Moul's
10 Schedule 5. This shows long-term debt increasing from \$378.2 million to
11 \$429.4 million, or a \$51.2 million net increase (i.e., new issues minus maturing debt).
12 The 12-month average short-term debt balance increases from \$3.5 million to
13 \$34.8 million. Finally, common equity increases from \$410.0 to \$509.3 million,
14 nearly a \$100 million increase over this approximately two-year period. The end
15 result of these various changes is a slightly more expensive capital structure than that
16 at present, with the common equity increasing from 51.8 to 52.3 percent.

17 Q. HOW DOES THIS PROPOSED CAPITAL STRUCTURE COMPARE TO
18 THE AVERAGE OF THE GAS UTILITY PROXY GROUP USED BY MR.
19 MOUL AND YOURSELF?

20 A. It is similar though slightly more equity laden. For example, Mr. Moul shows on
21 page 1 of Schedule 3 that his Gas Group average equity ratio (when short-term debt is
22 included, as it should be) is about 51 percent in 2011 (and a 49 percent five-year
23 average for the past five years).

1 Q. HOW WAS THE LONG-TERM DEBT BALANCE DETERMINED?

2 A. CPA's financing plan between now and June 2014 calls for \$138 million of new long-
3 term debt with cost rates averaging 5.5 percent. Long-term debt scheduled to mature
4 during this time frame is subtracted out.

5 Q. HOW DID THE COMPANY PROJECT THE INCREASE IN COMMON
6 EQUITY?

7 A. The entire increase in common equity is expected to come from the growth in
8 retained earnings; a 28 percent increase within about two years. This appears to be
9 based on three main assumptions. First, CPA is not expecting any parent company
10 equity infusions during this time period. (CPA, as a subsidiary, cannot raise external
11 equity independent of its parent.) Second, CPA does not at this time anticipate
12 paying any dividends to its parent during this time period, i.e., all earnings will be
13 retained. Third, CPA will earn and reinvest about \$100 million in earnings during
14 these two years. (See responses to I&E-RR-77-D and OCA III-7.) The first two
15 items are a matter of stated financial policy or plans (although plans can change).
16 The third item is merely an estimate of the result of CPA's operations.

17 Q. IN YOUR OPINION, IS THE EQUITY INCREASE A RELIABLE
18 PROJECTION?

19 A. No, it seems somewhat speculative because financing plans can change with
20 circumstances, and earnings extending out over two years are difficult to reliably
21 estimate. I do not consider the Company's estimate of its June 30, 2014 capitalization
22 balance to be either reliable or certain.

1 Q. DO YOU PROPOSE ANY CHANGES TO MR. MOUL'S PROJECTED
2 CAPITALIZATION?

3 A. Yes, I am proposing one change. The Company's 28 percent growth in retained
4 earnings seems overly optimistic and is largely unexplained. (See the Company's
5 response to OCA III-7.) The retained earnings growth is equivalent to roughly a
6 12 percent per year earned return on equity. CPA's most recent earnings report filed
7 with this Commission indicates an earned return on equity of about 9 percent for the
8 12 months ending September 2012. Mr. Moul's Schedule 2 shows that CPA's return
9 on equity during the previous five years ranged from about 9 to 11 percent, with the
10 exception of one year when it was nearly 15 percent. For purposes of projecting
11 capital structure, I accept all CPA financial planning assumptions (e.g., no dividend
12 payments; \$51 million increase in net long-term debt), but I am scaling back the
13 return on equity assumption to 10.0 percent per year. This is slightly higher than my
14 9.5 percent return on equity recommendation. In order to develop the June 30, 2014
15 balance, I begin with CPA's actual balance at June 30, 2012 as stated in its most
16 recent earnings report filed with this Commission, \$408.6 million. This is slightly
17 lower than Mr. Moul's stated actual balance at May 31, 2012. I then increase the
18 \$408.6 million by 10.0 percent per year, producing a balance at June 30, 2014 of
19 \$494.5 million, which is about \$15 million lower than Mr. Moul's estimate. This
20 revision produces a 51.58 percent common equity ratio, a result which is reasonably
21 consistent with both the Gas Group average and CPA's current capital structure.

22 In developing this recommendation, I am not at this time contesting any other
23 CPA financial planning assumptions. However, this does not mean that I am
24 necessarily either endorsing those assumptions or attesting to their accuracy. Rather,
25 my conclusion at this time is that a \$494.5 million equity ratio at June 30, 2014 is a

1 more reasonable projection than Mr. Moul's somewhat higher but unexplained
2 estimate.

3 Q. DO YOU ACCEPT MR. MOUL'S EMBEDDED COST OF LONG-TERM
4 DEBT OF 5.80 PERCENT?

5 A. No, I believe this figure is too high. This cost of debt is based on the assumption that
6 the \$138 million of planned new debt will carry a cost rate averaging about
7 5.5 percent. In response to I&E-RR-78-D and OCA III-4, the Company states that
8 this estimate is based on long-term Treasury rates of about 2.8 to 3.0 percent plus
9 credit spreads of about 2.6 percent.

10 While I have no quarrel with the Treasury rate estimates (assuming the
11 estimates are meant to apply to 30-year bonds), the 2.6 percent credit spread seems
12 excessive. In recent months, Moody's BBB utility bond yields have averaged about
13 4.8 percent, on roughly a 2.0 percent credit spread. The much higher credit spread
14 assumption in this case may be because CPA will be obtaining this debt from its
15 parent (or the NiSource financing subsidiary), and NiSource has a relatively weak
16 BBB- credit rating. (See Company response to I&E-RR-1-D for recent NiSource
17 credit rating reports.)

18 It is possible that 5.5 percent is a reasonable cost of debt estimate for
19 NiSource itself, but it is unfair to impose such a cost of debt premium on CPA
20 customers. As explained above, Mr. Moul and I both propose a CPA ratemaking
21 capital structure in line with the Gas Group, which itself has credit ratings that can be
22 characterized by high triple B or low single A. (See Mr. Moul's Schedule 3, page 2.)
23 NiSource's much lower credit rating is due to the fact that its actual capital structure
24 is approximately 60 percent debt and 40 percent equity. (See Mr. Moul's Exhibit

1 401, page 3 of 5.) Such a leveraged capital structure directly translates into relatively
2 weak credit metrics, and therefore, a high cost of debt.

3 NiSource's weak credit rating and elevated cost of debt should not be imposed
4 on CPA customers. Neither NiSource nor CPA is regarded as being particularly risky
5 from the standpoint of business risk by credit rating agencies. Indeed, Standard &
6 Poor's regards NiSource as "Excellent" for its business profile. The problem is
7 NiSource's high degree of debt leverage as determined by its management. Yet in
8 this case, CPA customers are being asked to pay for a cost of capital reflecting a
9 capital structure with 52 percent equity, not the much less expensive NiSource capital
10 structure with 40 percent equity. In other words, CPA customers must pay for the
11 cost of a strong capital structure but do not receive the corresponding benefit.

12 Q. HOW HAVE YOU CORRECTED THE COST OF DEBT?

13 A. At this time, I am repricing the \$138 million of new debt at 5.0 percent instead of
14 5.5 percent. This is much more in line with current market conditions for a credit
15 worthy gas distribution company with a "typical" (i.e., strong) capital structure. This
16 lowers CPA's June 30, 2014 cost of long-term debt from 5.80 percent (as proposed)
17 to 5.64 percent. Please note that some of CPA's existing debt may also be overstated,
18 but I propose only to reprice the planned new debt.

19 Q. HAVE YOU SIMILARLY ADJUSTED THE COST OF SHORT-TERM
20 DEBT?

21 A. Yes, although this is a relatively minor issue since short-term debt is a mere
22 3.6 percent of total capital. The Company proposes a relatively expensive cost rate
23 for this debt of 1.90 percent, an increase compared to the current cost rate of
24 1.57 percent. Again, this elevated cost rate for short-term debt may be attributable to

1 NiSource's weak credit rating. Therefore, it is more appropriate to use the current
2 1.57 percent than to assume an increase to 1.90 percent.

3 **B. Cost of Equity Risk Adjustments**

4 Q. HAS MR. MOUL INCLUDED A RISK ADJUSTMENT FOR CPA
5 RELATIVE TO HIS ESTIMATE OF THE GAS GROUP COST OF
6 EQUITY?

7 A. Yes. He includes a risk adjustment of 0.76 percent (76 basis points) for CPA, which
8 is an adder to the DCF and Risk Premium study results (but not the Comparable
9 Earnings). It appears that the 0.76 percent reflects his estimate of the cost rate
10 difference between a single A and triple B credit rating. (See the response to OCA
11 III-22.) While Mr. Moul's testimony discusses many aspects of risk, his
12 quantification of the risk adjustment itself clearly is based on NiSource's weak credit
13 rating, as discussed above. Since CPA does not have its own credit rating, Mr. Moul
14 implicitly "imputes" NiSource's credit rating to CPA, ignoring the fact that NiSource
15 and CPA have vastly different capital structures.

16 Q. DOES MR. MOUL RECOGNIZE THE RISK REDUCING BENEFIT OF
17 THE DSIC?

18 A. While Mr. Moul does not deny that the introduction of the DSIC can benefit CPA
19 going forward (and thereby reduce its risk), he appears to give it no recognition in his
20 "risk adder" recommendation. In addition, he briefly mentions the residential rate
21 design changes proposed in this case by CPA that are intended to stabilize and make
22 more certain the Company's revenue stream. But again, such changes, if approved,
23 do not affect his risk adder recommendation. His argument is that, to some extent or
24 degree, the Gas Group companies already have such rate mechanisms in place.

1 Q. DO YOU AGREE WITH MR. MOUL'S 0.76 PERCENT RISK
2 ADJUSTMENT?

3 A. While I do not reject the concept of a risk adjustment, I believe Mr. Moul's value of
4 0.76 percent is simply too high. There are two reasons for this. First, the
5 0.76 percent adder is based upon NiSource's relatively weak credit rating of BBB- (a
6 full letter grade lower than that of the Gas Group average) and imputed to CPA. As
7 explained above, this is due to NiSource's high degree of leverage (which weakens its
8 credit metrics) and has little or nothing to do with CPA's leverage or credit metrics.
9 CPA's capital structure is about the same as the Gas Group. If NiSource's capital
10 structure was set similar to CPA, it undoubtedly would enjoy a better credit rating,
11 although not necessarily single A. (Note that NiSource also has vertically-integrated
12 electric utility risks.) Mr. Moul's second point is that aside from the NiSource credit
13 rating, CPA also has above average risk associated with such factors as gas-on-gas
14 competition, capital spending burdens and other factors. While I do not totally reject
15 these arguments, the evidence on relative risk is not clear cut. There is certainly no
16 suggestion from credit rating reports that CPA (or the NiSource gas distribution
17 utilities in general) have business risk profiles worse than the average gas distribution
18 utility.

19 Q. WHAT ARE THE POTENTIAL RATE DESIGN CHANGES AT ISSUE?

20 A. As mentioned, the DSIC mechanism has been established by statute and will be
21 available for CPA going forward. This will certainly be viewed as a regulatory
22 feature that mitigates its capital spending, cost recovery risk. In this case, to enhance
23 revenue certainty, CPA has proposed a Revenue Normalization Adjustment (which
24 would adjust residential rates to achieve a target revenue level) as its primary
25 recommendation for its residential rate design, along with two alternative rate design

1 structures for the Commission's consideration. The two alternatives to Columbia's
2 primary proposal are a Weather Normalization Adjustment (which would provide for
3 a monthly billing adjustment to correct for weather that differs from a defined
4 normal) and a Levelized Distribution Charge. The OCA does not support any of
5 these three residential rate design options.

6 Q. SETTING ASIDE THE DSIC, WHICH WILL GO FORWARD, DO ANY
7 OF THE THREE RATE DESIGN OPTIONS HAVE COST OF EQUITY
8 IMPLICATIONS?

9 A. Yes. In an "all else held equal" context, these rate design mechanisms help to reduce
10 short-term or "between rate case" revenue uncertainty and thereby are favorable for
11 the utility's business risk. That said, I am not aware of any reliable or accepted
12 quantification of the cost of equity benefit. Mr. Moul does not suggest one, and his
13 quantification of his 0.76 percent risk adder appears not to be directly related to rate
14 design. Moreover, he does not propose a downward adjustment if one of these
15 mechanisms is adopted, nor does he increase his risk adder if CPA's rate design
16 proposal is rejected.

17 Q. WHAT IS YOUR POSITION ON RELATIVE RISK?

18 A. I believe that at the present time (and absent the adoption of one of the Company-
19 proposed rate design options) it is possible that CPA is riskier than the Gas Group as
20 a whole, but this allegedly greater risk is not clear cut. Mr. Moul's 0.76 percent adder
21 clearly is greatly overstated. As noted earlier, CPA may be viewed as slightly riskier
22 than the Gas Group as a whole since some Gas Group companies in some
23 jurisdictions are permitted to use mechanisms such as weather normalization or
24 revenue decoupling, mechanisms that the OCA does not support in this case.

1 First and foremost, the NiSource credit rating must be disregarded as being
2 inapplicable to CPA. Specifically, CPA's balance sheet capital structure is very much
3 in line with the Gas Group average. Second, the DSIC is an important advantage for
4 CPA relative to the Gas Group for capital spending cost recovery in the future. While
5 Mr. Moul points out that some Gas Group members have special infrastructure cost
6 recovery mechanisms, he has not shown that such mechanisms are widely adopted or
7 as effective as (or superior to) the DSIC. Thus, I view the DSIC as a going-forward
8 advantage for CPA not reflected in historical data. In addition to the availability of
9 the DSIC, CPA is permitted to use a fully forecasted future rate year in its base rate
10 cases. Third, even Mr. Moul concedes that CPA's Operating Ratio is at least as
11 favorable as the Gas Group average. Fourth, despite the many business risks for CPA
12 discussed by Mr. Moul (and CPA witness Kempic), CPA has generally been
13 successful in maintaining a reasonable level of earnings.

14 Q. PLEASE EXPLAIN THIS LAST POINT.

15 A. Mr. Moul's Schedule 2 shows that for the past five years (ending in 2011), CPA's
16 earned return on equity has averaged 11.2 percent, indicating that it has been able to
17 operate reasonably successfully. With the exception of one very good year when it
18 earned 14.9 percent, its earned ROE was in a relatively tight range of 9.5 to
19 11.4 percent, suggesting stability. The Gas Group was similarly successful with a
20 five-year average ROE of 11.1 percent – nearly identical to CPA.

21 Admittedly, historical ROE results by themselves cannot and should not be
22 used to draw definitive or strong conclusions about relative risk. Moreover, I am not
23 asserting CPA to be lower in risk (i.e., "less risky") than the Gas Group average. But
24 it does seem to suggest that the risk differences, if any, are not large.

1 Q. ARE THERE ANY OTHER FACTORS TO CONSIDER?

2 A. Yes. Some of the Gas Group members that Mr. Moul and I have selected have
3 significant non-regulated operations. Importantly, these non-regulated operations are
4 viewed as riskier than gas utility operations by investors. Any such non-regulated
5 risk increment is automatically included in the DCF, CAPM and risk premium studies
6 in this case. This is an additional reason why restraint should be exercised in
7 applying a risk adder to CPA and why Mr. Moul's 0.76 percent risk adder is
8 inappropriate and overstated.

9 Q. PLEASE SUMMARIZE YOUR CONCLUSION ON THE NEED FOR A
10 RISK ADDER.

11 A. The appropriateness of a risk adder for CPA, relative to the Gas Group cost of equity,
12 is unclear. Mr. Moul bases his 0.76 percent risk adder on the parent company's
13 relatively weak credit rating. But to some degree, that is the result of the parent's
14 more leveraged capital structure, and this credit rating is not necessarily applicable to
15 CPA. Mr. Moul does point out that some of the Gas Group companies in some
16 jurisdictions have been authorized the use of special rate mechanisms such as weather
17 normalization, decoupling or more certain fixed cost recovery, i.e., mechanisms that
18 can reduce a company's business risk. That argument potentially could support a
19 small risk adjustment absent implementation of such a rate mechanism for CPA, as
20 recommended by the OCA in this case. However, it is important to note that the
21 DSIC and the Company's ability to employ a fully forecasted future rate year in base
22 rate cases are distinct and important regulatory advantages for CPA.

1 Q. WHAT IS YOUR RECOMMENDATION CONCERNING A RISK
2 ADDER?

3 A. In the event the OCA's position on residential rate design is approved, I am
4 recommending that the Commission in this case consider a risk adder range of zero to
5 0.4 percent for CPA. The 0.4 percent is about one half the magnitude of Mr. Moul's
6 overstated adjustment, which he bases on the NiSource credit rating. This ROE adder
7 would improperly penalize CPA customers for NiSource's high degree of debt
8 leverage while denying customers the concomitant cost of capital savings from that
9 leverage. Nonetheless, 0.4 percent is a significant risk adjustment that could be
10 considered as an upper bound if the Commission finds that CPA, on balance, has
11 more business risk than the Gas Group and the Commission adopts the OCA's
12 recommendation on rate design. The lower bound of 0.0 percent would be
13 appropriate if the Commission finds that CPA has about as much business risk as the
14 Gas Group or if the Commission adopts one of the Company's residential rate design
15 proposals. My recommendation in this case of 9.5 percent is inclusive of the
16 midpoint of that range of 0.2 percent and embodies the OCA's position on rate
17 design.

18 Q. YOU MENTION THAT THE OCA IS NOT SUPPORTING THE
19 PROPOSED RISK-REDUCING ALTERNATIVE RESIDENTIAL RATE
20 DESIGN CHANGES. IF ONE OF THESE RATE DESIGN CHANGES IS
21 ADOPTED, HOW WOULD THAT AFFECT YOUR
22 RECOMMENDATION?

23 A. As noted above, the rate design alternatives can have some effect on CPA's business
24 risk profile, although this effect has not been quantified. Thus, in this case if one of
25 these rate design changes is adopted, the Commission should find that CPA is no

1 riskier than the Gas Group. Absent such a risk adder, my recommended ROE
2 becomes 9.3 percent, i.e., the Gas Group DCF midpoint.

3 Q. MR. MOUL ALSO RECOMMENDS A "SIZE"-RELATED RISK
4 ADJUSTMENT FOR CPA. HOW DOES THIS RELATE TO HIS
5 0.76 PERCENT RISK ADDER?

6 A. They are entirely different adjustments. The 0.76 percent risk adder is based on Mr.
7 Moul's risk assessment of CPA versus his Gas Group. This is a general risk adder to
8 his DCF and Risk Premium study results. The "size" adder only pertains to his
9 CAPM study, allegedly to "correct" for the fact that the reported beta figures used in
10 the CAPM study do not adequately capture the additional risk associated with a
11 company being relatively "small." In Section V.D., I explain why the "size" adder is
12 not needed for CPA in the CAPM study and thus should be rejected.
13
14

1 **IV. COST OF COMMON EQUITY**

2 **A. Using the DCF Model**

3 Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR ROE
4 RECOMMENDATION?

5 A. As a general matter, the ratemaking process is designed to provide the utility an
6 opportunity to recover its prudently-incurred costs of providing utility service to its
7 customers, including the reasonable costs of financing its used and useful investment.
8 Consistent with this "cost-based" approach, the fair and appropriate return on equity
9 award for a utility is its cost of equity. The utility's cost of equity is the return
10 required by investors (i.e., the "market return") to acquire or hold that company's
11 common stock. A return award greater than the market return would be excessive
12 and would overcharge customers for utility service. Similarly, an insufficient return
13 could unduly weaken the utility and impair incentives to invest.

14 Although the *concept* of the cost of equity may be precisely stated, its
15 quantification poses challenges to regulators. The market cost of equity, unlike most
16 other utility costs, cannot be directly observed (i.e., investors do not directly,
17 unambiguously state their return requirements), and it therefore, must be estimated
18 using analytic techniques. The DCF model is one such prominent technique familiar
19 to analysts, this Commission and other utility regulators.

20 Q. IS THE COST OF EQUITY A FAIR RETURN AWARD FOR THE
21 UTILITY AND ITS CUSTOMERS?

22 A. Generally speaking, I believe it is. A return award commensurate with the cost of
23 equity generally provides fair and reasonable compensation to utility investors and
24 normally should allow efficient utility management to successfully finance its

1 operations on reasonable terms. Setting the return on equity equal to a reasonable
2 estimate of the cost of equity also is generally fair to ratepayers.

3 I recognize that there can be exceptions to this general rule. For example, in
4 some instances, utilities have obtained rate of return adders as a reward for asserted
5 good management performance or lowered returns where performance is subpar. In
6 this case, the Company is making an explicit request for a management performance
7 adder of 10 basis points in addition to Mr. Moul's 11.15 percent CPA cost of equity
8 estimate. Nonetheless, the principal task at hand is one of measuring the cost of
9 equity.

10 Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

11 A. It should be understood that the cost of equity is essentially a market price, and as
12 such, it is ultimately determined by the forces of supply and demand operating in
13 financial markets. In that regard, there are two key factors that determine this price.
14 First, a company's cost of equity is determined by the fundamental conditions in
15 capital markets (e.g., outlook for inflation, monetary policy, changes in investor
16 behavior, investor asset preferences, the general business environment, etc.). The
17 second factor (or set of factors) is the business and financial risks of the Company in
18 question. For example, the fact that a utility company operates principally as a
19 regulated monopoly, dedicated to providing an essential service (in this case gas
20 distribution utility service), typically would imply very low business risk and
21 therefore, a relatively low cost of equity. CPA's relatively strong balance sheet and
22 the favorable business risk profile assessment by credit rating agencies (i.e., S&P)
23 also contribute to its relatively low cost of equity.

1 Q. DOES MR. MOUL INCORPORATE THESE PRINCIPLES IN HIS
2 TESTIMONY?

3 A. Not entirely. Some of his non-DCF analyses do not adhere closely to these
4 principles. For example, risk premium and comparable earnings studies make
5 excessive use of historical or non-market (i.e., pure accounting-type) data to derive
6 equity return results. Although the DCF clearly is a market-based and conceptually
7 sound model, Mr. Moul distorts his analysis by introducing his leverage adjustment,
8 which is unrelated to any investor or market requirements.

9 Q. WHAT METHODS ARE YOU USING IN THIS CASE?

10 A. I employ both the DCF and CAPM models, applied to a proxy group of gas
11 distribution utility companies. However, for reasons discussed in my testimony,
12 I emphasize the DCF model results (as applied to the gas utility group) in formulating
13 my recommendation. It has been my experience that most utility regulatory
14 commissions (federal and state), including Pennsylvania, heavily emphasize the use
15 of the DCF model to determine the cost of equity in and setting the fair return. As a
16 check (and partly to respond to Mr. Moul), I also perform a CAPM study, which also
17 is based on the same gas distribution utility proxy group companies used in my DCF
18 study.

19 Q. PLEASE DESCRIBE THE DCF MODEL.

20 A. As mentioned, this model has been widely relied upon by the regulatory community,
21 including this Commission. Its widespread acceptance among regulators is due to the
22 fact that the model is market-based and is derived from standard economic/financial
23 theory. The model, as typically used, is also transparent and generally
24 understandable. I do not believe that an obscure or highly arcane model would
25 receive the same degree of regulatory acceptance.

1 The theory begins by recognizing that any publicly-traded common stock
2 (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows
3 *expected by investors*. The objective is to estimate that discount rate.

4 Using certain simplifying assumptions that I believe are generally reasonable
5 for utilities, the DCF model for dividend paying stocks can be distilled down as
6 follows:

7 $K_e = (D_0/P_0) (1 + 0.5g) + g$, where:

8 K_e = cost of equity;

9 D_0 = the current annualized dividend;

10 P_0 = stock price at the current time; and

11 g = the long-term annualized dividend growth rate.

12 This is referred to as the constant growth DCF model because for
13 mathematical simplicity, it is assumed that the growth rate is constant for an
14 indefinitely long time period. While this assumption may be unrealistic in many
15 cases, for traditional utilities (which tend to be more stable than most unregulated
16 companies) the assumption generally is reasonable, particularly when applied to a
17 group of companies.

18 Q. HOW HAVE YOU APPLIED THIS MODEL?

19 A. Strictly speaking, the model can be applied only to publicly-traded companies,
20 i.e., companies whose market prices (and therefore market valuations) are
21 transparently revealed. Consequently, the model cannot be applied to CPA, which
22 is a wholly-owned subsidiary of CEG and, in turn, is owned by NiSource. Therefore,
23 a market proxy is needed. In this case, the NiSource parent could serve as that market
24 proxy, since it is publically traded. However, the majority of NiSource's assets are

1 devoted to other than gas distribution utility service, and I therefore, have excluded it
2 (as has Mr. Moul). More importantly, I am reluctant to rely upon a single-company
3 DCF study (nor does Mr. Moul), since such studies tend to be less reliable than using
4 “group” data.

5 In any case, I believe that an appropriately selected proxy group is likely to be
6 more reliable than a single company study. This is because there is “noise” or
7 fluctuations in stock price or other data that cannot always be readily accounted for in
8 a simple DCF study. The use of an appropriate and robust proxy group helps to allow
9 such “data anomalies” to cancel out in the averaging process.

10 For the same reason, I prefer to use market data that are relatively current but
11 averaged over a relatively recent period of six months rather than purely relying upon
12 “spot” market data. It is important to recall that this is not an academic exercise but
13 involves the setting of “permanent” utility rates that are likely to be in effect for
14 several years. The practice of averaging market data over a period of several months
15 can add stability to the results.

16 Q. ARE YOU EMPLOYING THE DCF MODEL USING A GAS UTILITY
17 PROXY GROUP?

18 A. I am using a proxy group that consists of nine of the companies included in the Value
19 Line Gas Utility Industry Group. Mr. Moul uses the very same proxy group of gas
20 utility companies. Like Mr. Moul, I have elected to exclude two of the Value Line
21 gas utility companies: UGI (which has extensive propane and electric utility
22 operations) and NiSource (which as I mentioned is also a vertically-integrated electric
23 utility).

24 These nine proxy companies are listed on Schedule MIK-3, page 1 of 1, along
25 with several risk indicators. Since this proxy group is identical to that used by

1 Mr. Moul, our DCF study results can be directly compared without differences in
2 sample selection obscuring the comparison.

3 It should be noted that although the proxy gas companies are primarily
4 regulated utilities, some also have non-regulated operations that may be perceived as
5 riskier than utility operations (e.g., competitive energy services). I make no specific
6 adjustment to the DCF cost of capital results or my final recommendation for those
7 potentially riskier non-regulated operations. Overall, the non-utility operations for
8 these companies generally are relatively modest and do not unduly distort the task of
9 estimating the utility cost of capital. Nonetheless, the existence of non-utility risk
10 does add to the conservatism of my results and ultimate ROE recommendation.

11 Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

12 A. I have elected to use a six-month time period to measure the dividend yield
13 component (Do/Po) of the DCF formula. Using the Standard & Poor's *Stock Guide*,
14 I compiled the month-ending dividend yields for the six months ending September
15 2012, the second and third calendar quarters of 2012. As of this writing, it does not
16 appear that the cost of capital has materially changed since mid 2012. The second
17 and third quarters of 2012 were generally a period of gains and stability for the broad
18 stock market, with utility stocks remaining reasonably stable.

19 I show these dividend yield data on page 2 of Schedule MIK-4 for each month
20 and each proxy company, April through September 2012. Over this six-month
21 period, the proxy group average dividend yields were relatively stable, ranging from a
22 low of 3.63 percent in July to a high of 3.90 percent in May 2012, averaging
23 3.74 percent for the full six months.

24 For DCF purposes and at this time, I am using a proxy group dividend yield of
25 3.74 percent.

1 Q. IS 3.74 PERCENT YOUR FINAL DIVIDEND YIELD?

2 A. Not quite. Strictly speaking, the dividend yield used in the model should be based on
3 the per share dividend the investor expects to receive over the next 12 months. This
4 is because the DCF is a forward-looking or expectational model. Using the standard
5 "half year" growth rate adjustment technique, the DCF adjusted yield becomes
6 3.8 percent. This is based on assuming that half of a year growth is 2.75 percent
7 (i.e., as shown later in this section, a full year growth is 5.5 percent). This technique
8 provides a reasonable estimate of the dividend payment that an investor purchasing
9 the stock today will receive during the first full year of stock ownership.

10 Q. DOES MR. MOUL EMPLOY THE SAME GROWTH RATE
11 ADJUSTMENT?

12 A. I understand that Mr. Moul also employs this standard half-year growth adjustment to
13 the measured dividend yield along with using other adjustment methods. Moreover,
14 he also employs six months of market data to develop his dividend yield. Despite his
15 use of a slightly different adjustment procedure, Mr. Moul obtains a 3.90 percent
16 proxy group adjusted dividend yield, which is very close to my 3.8 percent yield,
17 despite the fact that we used different time periods for the market data.

18 Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

19 A. Unlike the dividend yield, the investor growth rate cannot be directly observed but
20 instead must be inferred through a review of available evidence. The growth rate in
21 question is the *long-run* dividend per share growth rate, but analysts frequently use
22 earnings growth as a proxy for (long-term) dividend growth. This is because in the
23 long-run earnings are the ultimate source of dividend payments to shareholders, and
24 this is likely to be particularly true for a large group of utility companies.

1 One possible approach is to examine historical growth as a guide to investor
2 expected future growth, for example the recent five-year or 10-year growth in
3 earnings, dividends and book value per share. However, my experience with utilities
4 in recent years is that these historic measures have been very volatile and are not
5 necessarily reliable as prospective measures. This is due in part to extensive
6 corporate or financial restructuring. I note that Mr. Moul does not appear to rely
7 upon historical growth rates as an indicator of long-term growth for gas distribution
8 companies for DCF purposes. The DCF growth rate should be prospective, and one
9 useful source of information on prospective growth is the projections of earnings per
10 share (typically five years) prepared by securities analysts. It appears that Mr. Moul
11 places exclusive weight on this information for his Gas Group, and I agree that it
12 warrants substantial emphasis though not exclusive emphasis.

13 Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE
14 EVIDENCE.

15 A. Schedule MIK-4, page 3 presents five available and well-known public sources of
16 projected earnings growth rates. Four of these five sources -- YahooFinance,
17 MSNMoney, Reuters and CNNfn -- provide averages from securities analyst surveys
18 conducted by or for these organizations (typically they report the mean or median
19 value). The fifth, Value Line, is that organization's own estimates and is available
20 publically on a subscription basis. Value Line publishes its own projections using
21 annual average earnings per share for a base period of 2009-2011 compared to the
22 annual average for the forecast period of 2015-2017.

23 As this schedule shows, the growth rates for individual companies vary
24 somewhat among the five sources. These proxy group averages are 5.0 percent for
25 CNNfn, 4.9 percent for YahooFinance, 4.7 percent for MSNMoney, 4.9 percent for

1 Reuters and 4.9 percent for Value Line.¹ Thus, the range of growth rates among the
2 five sources is a very narrow 4.7 to 5.0 percent for the nine-company group. The
3 average of these five sources is 4.9 percent, and I have used these results (along with
4 other evidence) in obtaining a reasonable expected growth range for the group of
5 5.0 to 6.0 percent.

6 Q. IS THERE ANY OTHER EVIDENCE THAT SHOULD BE CONSIDERED?

7 A. Yes. There are a number of reasons why investor expectations of long-run growth
8 could differ from the limited, five-year earnings projections prepared by securities
9 analysts. Consequently, while securities analyst estimates should be considered and
10 given significant weight, these growth rates should be subject to a reasonableness test
11 and corroboration, to the extent feasible.

12 On Schedule MIK-4, page 4 of 5, I have compiled three other measures of
13 growth published by Value Line, i.e., growth rates of dividends and book value per
14 share and the long-run retained earnings growth. (Retained earnings growth reflects
15 the growth over time one would expect from the reinvestment of retained earnings,
16 i.e., earnings not paid out as dividends.) As shown on this schedule, these growth
17 measures for the nine companies tend to be similar to or somewhat lower than analyst
18 earnings growth projections. For the nine companies, dividend growth averages
19 3.9 percent, book value growth averages 4.4 percent, and earnings retention growth
20 averages 5.2 percent.

21 Some analysts and regulators favor the use of earnings retention growth (often
22 referred to as "sustainable growth"), which Value Line indicates to be 5.2 percent (for
23 the nine gas proxy companies). However, at least in theory, the sustainable growth

¹ Please note that for reasons that are not clear, YahooFinance publishes a negative growth rate for AGL Resources, one of the proxy group companies. This figure is anomalous and may be in error, given the very different values reported by the other four sources. For this reason, I have excluded this figure.

1 rate also should include "an adder" to reflect potential future earnings growth
2 contribution from issuing new common stock at prices above book value (referred to
3 as "external growth" or the "s x v" factor). In practice, this factor is difficult to
4 estimate since future stock issuances of companies over the long-term are an
5 unknown, and there is little reliable information on this for investors. Nonetheless, I
6 have estimated this "external growth" factor using Value Line projections for these
7 nine companies of the growth rate (through 2015-2017) in shares outstanding, along
8 with the current ("recent") stock price premium over book value. This is a common
9 method for calculating the external growth factor. For these nine companies, the
10 external growth rate calculated in this manner averages about 0.8 percent. The sum
11 of "internal" or earnings retention growth factor (i.e., 5.2 percent) and the "external"
12 growth rate factor (i.e., 0.8 percent) is 5.9 percent.

13 Given this estimate of 5.9 percent for the sustainable growth rate and
14 4.9 percent for analyst earnings projections, a reasonable DCF growth rate range is
15 5.0 to 6.0 percent to appropriately reflect uncertainty.

16 Q. HOW DOES YOUR GROWTH RATE RANGE OF 5.0 TO 6.0 PERCENT
17 COMPARE TO MR. MOUL'S RECOMMENDED DCF GROWTH RATE?

18 A. They are reasonably similar. Mr. Moul recommends a DCF growth rate factor for the
19 same gas utility proxy group of 5.25 percent. (Testimony, page 25.) The midpoint of
20 my range is 5.5 percent, which is only modestly higher than his estimate, which I
21 understand is based primarily on analyst estimates.

22 Q. WHAT IS YOUR DCF CONCLUSION?

23 A. I summarize my DCF analysis on page 1 of Schedule MIK-4. The adjusted dividend
24 yield for the six months ending September 2012 is 3.8 percent for this group.

25 Available evidence would support a long-run growth rate in the range of

1 approximately 5.0 to 6.0 percent, as explained above. Summing the adjusted yield
2 and growth rate range produces a total return of 8.8 to 9.8 percent, and a midpoint
3 result of 9.3 percent. Reliance on analyst earnings projections would tend to support
4 a result toward the lower end of that range, while the sustainable growth rate
5 produces a higher DCF result. I then add a risk factor range of 0.0 to 0.4 percent as
6 discussed in Section III of my testimony, contingent on acceptance of the OCA's rate
7 design position. This produces a final cost of equity range of 8.8 to 10.2 percent, with
8 a midpoint of 9.5 percent, which is my recommendation at this time, or 9.3 percent if
9 the Company's position on rate design is accepted.

10 Q. HOW DOES YOUR 9.3 PERCENT DCF MIDPOINT (BEFORE RISK
11 ADJUSTMENT) COMPARE TO MR. MOUL'S DCF ESTIMATE FOR
12 GAS UTILITIES?

13 A. Mr. Moul reports a DCF estimate of 9.79 percent, which includes an extraneous adder
14 of 0.64 percent for "leverage." Without the adder, his DCF estimate is 9.15 percent,
15 which is lower than my 9.3 percent midpoint.

16 B. The CAPM Analysis

17 Q. PLEASE DESCRIBE THE CAPM MODEL.

18 A. The CAPM is a form of the "risk premium" approach and is based on modern
19 portfolio theory. Based on my experience, the CAPM is the cost of equity method
20 most often used in rate cases after the DCF method, and it is one of Mr. Moul's three
21 cost of equity methods. (His comparable earnings calculations do not provide a
22 market-based cost of equity estimate.)

23 According to this model, the cost of equity (K_e) is equal to the yield on a risk-
24 free asset plus an equity risk premium multiplied by a firm's "beta" statistic. "Beta"
25 is a firm-specific risk measure, which is computed as the movements in a company's

1 stock price (or market return) relative to contemporaneous movements in the broadly
2 defined stock market (e.g., the S&P 500 or the New York Stock Exchange
3 Composite). This measures the investment risk that cannot be reduced or eliminated
4 through asset diversification (i.e., holding a broad portfolio of assets). The overall
5 market, by definition, has a beta of 1.0, and a company with lower than average
6 investment risk (e.g., a utility company) would have a beta below 1.0. The “risk
7 premium” is defined as the expected return on the overall stock market minus the
8 yield or return on a risk-free asset.

9 The CAPM formula is:

10 $K_e = R_f + \beta (R_m - R_f)$, where:

11 K_e = the firm’s cost of equity

12 R_m = the expected return on the overall market

13 R_f = the yield on the risk free asset

14 β = the firm (or group of firms) risk measure.

15 Two of the three principal variables in the model are directly observable – the
16 yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example,
17 Value Line publishes estimated betas for each of the companies that it covers, and
18 Mr. Moul uses those betas to the exclusion of all other sources. The greatest
19 difficulty, however, is in the measurement of the expected stock market return (and
20 therefore, the equity risk premium), since that variable cannot be directly observed.

21 While the beta itself also is “observable,” different investor services provide
22 differing calculations of betas depending on the specific procedures and methods that
23 they use. These differences can have large impacts on the CAPM results. In this

1 case, both Mr. Moul and I use Value Line published betas, although Mr. Moul then
2 makes an improper upward adjustment to those betas to reflect "leverage."

3 Q. HOW HAVE YOU APPLIED THIS MODEL?

4 A. For purposes of my CAPM analysis, I have used a long-term (i.e., 30-year) Treasury
5 yield as the risk-free return along with the average beta for the gas utility proxy
6 group. (See Schedule MIK-3, page 1 of 1, for the company-by-company betas.) In
7 last six months, long-term (i.e., 30-year) Treasury yields have averaged
8 approximately 2.8 percent (see page 2 of Schedule MIK-5), and the recent Value Line
9 betas for my gas utility proxy group average 0.66. I note that Mr. Moul has elected to
10 use betas for the gas utility group that average 0.67, but he inappropriately increases
11 this to 0.75. I discuss Mr. Moul's "leverage adjustment" rationale for the beta
12 increase in the next section of my testimony. Finally, and as explained below, I am
13 using an equity risk premium range of 5 to 8 percent, although I also provide
14 calculations using a higher risk premium (i.e., 9 percent) as a sensitivity test.

15 Using these data inputs, the CAPM calculation results are shown on page 1 of
16 Schedule MIK-5. My low-end cost of equity estimate uses a risk-free rate of
17 2.8 percent, a proxy group beta of 0.66 and an equity risk premium of 5 percent.

$$18 \quad K_e = 2.8\% + 0.66 (5.0\%) = 6.1\%$$

19 The upper end estimate uses a risk-free rate of 2.8 percent, a proxy group beta of 0.66
20 and an equity risk premium of 8.0 percent.

$$21 \quad K_e = 2.8\% + 0.67 (8.0\%) = 8.1\%$$

22 Thus, with these inputs the CAPM provides a cost of equity range of 6.1 to
23 8.1 percent, with a midpoint of 7.1 percent. The CAPM analysis produces a midpoint
24 result significantly lower than the range of results obtained for my gas utility group
25 DCF analysis, but I have not placed reliance on the CAPM returns in formulating my

1 return on equity recommendation in this case. This is due to the unusual behavior of
2 Treasury bond markets (the recent "flight to quality problem"), and with the
3 economic uncertainty during the past year, it is difficult to assess the overall equity
4 risk premiums for the stock market at this time.

5 Q. WHAT RESULT WOULD YOU OBTAIN USING MR. MOUL'S MARKET
6 RISK PREMIUM?

7 A. For his CAPM study, Mr. Moul has selected a market risk premium of about
8 9.0 percent. In conjunction with the actual gas utility beta of 0.66 (based on Value
9 Line data for the gas utility group) and a 2.8 percent Treasury bond yield, the CAPM
10 produces:

$$K_e = 2.8\% + 0.66 (9.0\%) = 8.7\%$$

12 While I view Mr Moul's 9.0 percent market risk premium estimate as
13 excessive, given current data on long-term Treasury yields and gas utility betas (from
14 Value Line), the CAPM using this very high risk premium value produces a return of
15 8.7 percent. This high end estimate is below my recommendation of 9.3 or
16 9.5 percent (depending upon the resolution of the rate design issue).

17 Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM STUDY IS
18 YOUR EQUITY MARKET RETURN RISK PREMIUM OF 5 TO
19 8 PERCENT. HOW DID YOU DERIVE THAT RANGE?

20 A. There is a great deal of disagreement among analysts regarding the reasonably
21 expected market return on the stock market as a whole and therefore, the risk
22 premium. In my opinion, a reasonable overall stock market risk premium to use
23 would be about 6 to 7 percent, which today would imply a stock market return of
24 about 9.0 to 10.0 percent. Due to uncertainty concerning the true market return value,
25 I am employing a broad range of 5 to 8 percent as the overall market rate of return,

1 which would imply a market equity return of roughly 8 to 11 percent for the overall
2 stock market.

3 Q. DO YOU HAVE A SOURCE FOR THAT RANGE?

4 A. Yes. The well-known finance textbook by Brealey, Myers and Allen (*Principles of*
5 *Corporate Finance*) reviews a broad range of evidence on the equity risk premium.

6 The authors of the risk premium literature conclude:

7
8 Brealey, Myers and Allen have no official position on the issue,
9 but we believe that a range of 5 to 8 percent is reasonable for the
10 risk premium in the United States. (Page 154)

11 I would note that Mr. Moul's 9.0 percent overall market risk premium
12 somewhat exceeds the upper end of that range. My "midpoint" risk premium of
13 roughly 6.5 percent falls well within that range.

14 There is one important caveat to consider here regarding the 5 to 8 percent
15 range that the authors believe is supported by the literature. It appears that the 5 to
16 8 percent range is specified relative to short-term Treasury yields, not relative to long-
17 term (i.e., 30-year) Treasury yields. At this time, the application of the CAPM using
18 short-term Treasury yields would not be meaningful because those yields within the
19 past year have approximated zero. It therefore, could be argued that the 5 to 8 percent
20 range of Brealy *et al.* is overstated if a long-term Treasury yield is used as the risk-
21 free rate, i.e., the practice followed by both Mr. Moul and me.

22

1 **V. MR. MOUL'S COST OF EQUITY ANALYSES**

2 A. **Overview of Mr. Moul's Methods**

3 Q. HOW HAS MR. MOUL DEVELOPED HIS RETURN ON COMMON
4 EQUITY RECOMMENDATION IN THIS CASE?

5 A. Mr. Moul employs four methods, with three of the methods purporting to be market-
6 based approaches for estimating the cost of equity. The fourth method, "Comparable
7 Earnings," is neither market-based nor is it a method that estimates CPA's cost of
8 equity capital. It is unclear how much weight is attributed by Mr. Moul to this
9 method in developing his recommendation in this case. Since Comparable Earnings
10 is not designed to measure the market cost of equity, I only briefly discuss that
11 method.

12 The four methods produce the following results: (1) DCF -- 10.55 percent; (2)
13 Risk Premium -- 11.01 percent; (3) CAPM -- 11.13 percent; and (4) Comparable
14 Earnings -- 12.70 percent. Mr. Moul takes the simple average of these three studies
15 (i.e., implicitly assigning equal weight to each) and obtains 11.35 percent, with a
16 median of 11.07 percent. He then recommends a range of 11.0 to 11.3 percent.
17 (Response to OCA III-20.) Mr. Moul includes risk adjustments for CPA's asserted
18 greater risk as compared to the gas utility proxy group, and he adds a 10 basis point
19 bonus to the recommended ROE for outstanding management performance.

20 Q. PLEASE SUMMARIZE MR. MOUL'S ADDERS APPLIED TO HIS
21 PROXY GROUP COST OF EQUITY STUDIES.

22 A. They are as follows:

- 23 (1) Leverage: +0.64% DCF and CAPM
24 (2) Size: +1.14% CAPM only
25

1 (3) CPA risk/credit quality: +0.76% DCF, Risk Premium

2 (4) Outstanding management: +0.1% all methods

3 Q. WHAT WOULD HIS COST OF EQUITY ESTIMATES BE WITHOUT
4 THE ADDERS?

5 A. For his three cost of equity methods (i.e., excluding Comparable Earnings), his cost
6 of equity results would be:

7

(1)	DCF:	$3.9\% + 5.25\%$	=	9.15%
(2)	CAPM:	$3.25\% + 0.67 (9.0\%)$	=	9.28%
(3)	Risk Premium:	$4.75\% + 5.5\%$	=	<u>10.25%</u>
Average				9.56%

8

9 These results demonstrate that the prevailing cost of capital evidence supports a result
10 within my recommended range and close to my recommendation. The driver of Mr.
11 Moul's much higher recommendation is his various adders, not the basic cost of
12 equity evidence itself.

13 **B. The DCF Analysis**

14 Q. WHAT ARE YOUR CONCERNS REGARDING MR. MOUL'S DCF
15 ANALYSIS?

16 A. With one major exception, Mr. Moul's DCF study and my own are quite similar. We
17 both employ the same gas utility proxy group, six-month time period for market data,
18 and similar (though not identical) methods for adjusting forward the dividend yield.
19 In addition, both of us make use of publically-available, five-year earnings
20 projections data as a proxy for the long-term dividend per share growth expected by
21 investors. The difference is that Mr. Moul relies on these projections exclusively
22 (i.e., considers no other information), whereas I use the earnings projections in

1 conjunction with a fundamental analysis (often referred to as retained earnings
2 growth) to obtain a sustainable growth rate as required by the DCF model.

3 While I see potential problems with exclusive reliance on analysts' earnings
4 growth rate projections, in this particular case it makes very little difference in
5 comparing our respective DCF study results. Mr. Moul obtains a DCF proxy group
6 growth rate of 5.25 percent, whereas the midpoint of my growth rate range is a
7 somewhat higher 5.5 percent.

8 The one substantive difference between our two DCF studies is Mr. Moul's
9 inclusion of an extraneous "leverage" adjustment of 0.64 percent. This adjustment
10 appears to be included to provide extra compensation to the utility (i.e., excess
11 earnings) because standard ratemaking employs a book value capital structure instead
12 of a market value capital structure. Of course, the main difference between the two
13 capital structure measures arises from the fact that the proxy gas companies have
14 market-to-book ratios greatly in excess of 1.0. If that was not the case, then the
15 market value and book value capital structures would be nearly identical, and based
16 on Mr. Moul's methodology there would be no leverage adjustment. This adjustment
17 is improper, has nothing to do with the market-determined cost of capital, is unrelated
18 to accepted DCF practice and is essentially an attack on traditional, cost-based
19 ratemaking. The leverage adjustment provides additional earnings that investors do
20 not require and that is not needed to meet the capital attraction standard.

21 Q. WHAT WOULD MR. MOUL'S DCF STUDY PRODUCE ABSENT THE
22 LEVERAGE ADJUSTMENT?

23 A. I show his gas proxy group DCF results below with and without his leverage
24 adjustment.

1 With: $K_e = 3.9\% + 5.25\% + 0.64\% = 9.79\%$

2 Without: $K_e = 3.9\% + 5.25\% + 0.0\% = 9.15\%$

3 His DCF result just using the standard formula absent the leverage adjustment is
4 9.15 percent, which is reasonably close to my own midpoint of 9.3 percent for this
5 same proxy group.

6 Q. IS THE TYPE OF LEVERAGE ADJUSTMENT PROPOSED BY MR.
7 MOUL GENERALLY OR WIDELY ACCEPTED?

8 A. No. Analysts sometimes do recognize a cost of equity adjustment for differences in
9 debt leverage (or credit quality rating) between the subject utility and the proxy group
10 average. Indeed, Mr. Moul has included a CPA risk adder totally separate from his
11 leverage adjustment for CPA's allegedly greater business risk. In my opinion, any
12 such an adjustment should be small (if, indeed, any adjustment is needed at all) since
13 CPA has a ratemaking capital structure that is very similar to the Gas Group average.

14 Mr. Moul's leverage adjustment specifically pertains to market versus book
15 capital structures and must always *increase* the DCF study result whenever market-
16 to-book ratios exceed 1.0. This adjustment has received almost no support among
17 either rate of return analysts (be they consumer witnesses, Commission staff
18 witnesses or utility witnesses) or regulatory commissions. While Mr. Moul's
19 testimony cites to some limited number of cases in which a leverage adjustment of
20 some form was accepted, none of these cases have taken place since 2007, and he
21 cites no such cases outside of Pennsylvania.

22 Q. IS THE LEVERAGE ADJUSTMENT A MARKET-TO-BOOK
23 ADJUSTMENT TO THE STANDARD DCF MODEL RESULT?

24 A. Yes. While Mr. Moul describes the adjustment as resulting from differences "in risk"
25 between market value and book value capital structures, that asserted difference is

1 mainly attributable to proxy company market-to-book ratios exceeding 1.0. Hence, it
2 is little more than a market-to-book adjustment. Moreover, the adjustment is
3 counterintuitive. Gas companies enjoy high market-to-book ratios (much greater than
4 1.0) in part because they are perceived as being very low in risk. This means
5 investors are willing to pay a premium for gas utility assets or earnings because they
6 perceive the investment as having very favorable risk attributes. As the market-to-
7 book ratio increases (i.e., investors bid up the price of the stock), Mr. Moul's
8 adjustment and therefore, ROE recommendation would become ever larger. In other
9 words, the lower the Company's risk, the higher is Mr. Moul's adjusted DCF result
10 due to this adder.

11 Mr. Moul does not claim that his market-to-book adjustment is supported by
12 DCF theory or is needed to accurately measure the market cost of equity. Rather, it is
13 needed "to make the DCF results relevant to the capitalization measured at book
14 value (as is done for rate setting purposes); the market-derived cost rate cannot be
15 used without modification." (Testimony, page 27)

16 In this statement, Mr. Moul reveals two attributes regarding this adjustment.
17 The first is that the use of book value capital structure (instead of market value) is
18 somehow an infirmity of the regulation process, and since he cannot do anything
19 about that, his solution instead is to modify his DCF model by including an "adder."
20 Second, this statement concedes that the leverage adjustment is not even part of the
21 "market-derived [DCF] cost rate." Rather, it is a necessary "modification" to what
22 financial markets require, as determined by the standard DCF model.

1 Q. IS THERE A RISK DIFFERENCE BETWEEN A COMPANY'S BOOK
2 VALUE AND MARKET VALUE CAPITAL STRUCTURE?

3 A. No. It is merely two different ways of measuring the same thing. For the proxy gas
4 companies, the book value capital structure is readily available to investors from
5 publications such as Value Line and S&P credit reports. Investors, if they wish to do
6 so, can also easily calculate at least an approximation of the company's market value
7 capital structure just as Mr. Moul did. They are therefore, aware that market-to-book
8 ratios exceed 1.0 for these companies, and if they think this matters, it would be
9 automatically captured into the market return requirements for these investors. This
10 is what the standard DCF model measures. The point is that a standard application of
11 the DCF model automatically and fully takes into account any differences between
12 market and book capital structures, without including an extraneous "addor." The
13 fact that a company's market value capital structure and book value capital structure
14 may differ does not by itself make that company any more or less risky. Moreover,
15 investors are fully aware that regulators universally use book value for ratemaking,
16 and this basic fact is priced into utility stocks. There is no risk difference (or return
17 requirement) omitted from the DCF model that needs to be added in by a contrived
18 leverage adjustment.

19 Mr. Moul is free to argue that CPA is riskier than his Gas Group, and in that
20 regard he has included a risk adder of 0.76 percent. With the leverage adjustment he
21 includes a second (alleged to be related to financial risk) adder of 0.62 percent.

1 C. **The Risk Premium Analysis**

2 Q. HOW HAS MR. MOUL ESTIMATED THE COST OF EQUITY USING
3 THE RISK PREMIUM METHOD?

4 A. This is a relatively simple analysis. Mr. Moul identifies a prospective (or forecasted)
5 single A utility bond yield of 4.75 percent as of the time he prepared his testimony.
6 He obtains a historical-based risk premium of 5.5 percent using after-the-fact market
7 returns for the S&P Public Utility Index versus single A utility bonds. The sum of the
8 prospective single A bond yield and the historical risk premium is 10.25 percent,
9 which he uses as a cost of equity measure for the proxy group. He then adds his
10 0.76 CPA risk factor, obtaining a final CPA cost of equity of 11.01 percent.

11 Q. WHAT IS YOUR ASSESSMENT OF THIS ANALYSIS?

12 A. There are a number of infirmities with this method that lead Mr. Moul to overstate the
13 cost of equity for both CPA and the proxy group. First, the 4.75 percent prospective
14 cost of single A utility debt is overstated. In recent months, single A utility bond
15 yields have been well below 5 percent, i.e., closer to about 4.0 to 4.5 percent. (See
16 Schedule MIK-2, page 4 of 4.) Second, Mr. Moul's risk premium study uses almost
17 no data specific to CPA or even to gas utilities generally. The S&P Utility index that
18 he uses is dominated by electric utility companies, some having vast amounts of
19 unregulated operations (e.g., Exelon, Constellation, Duke Energy, NRG, etc.). This
20 group is a rather poor risk proxy for CPA's gas distribution utility operations. Third,
21 Mr. Moul's historical time frame for measuring the risk premium ends abruptly in
22 2007 -- about five years ago. Thus, the utility stock price performance in recent years
23 is omitted from his study. Fourth, and most important, Mr. Moul uses an arbitrary
24 and non-standard method for measuring the historic risk differences.

1 Q. PLEASE EXPLAIN THE LAST POINT.

2 A. Mr. Moul's risk premium is calculated using historic market returns for the S&P
3 utility index versus single A utility bonds, 1928-2007. The risk premium is the
4 "average" annual difference in returns over that period and various subperiods. He
5 employs three definitions of the "average" -- geometric mean, median and arithmetic
6 mean. He then assigns a weight of 25 percent each to the geometric mean and
7 median and 50 percent to the arithmetic mean.

8 The most serious problem is that the median is simply not an accepted method
9 for measuring the historic average market return over a long time period. In this case,
10 the median produces an outlandishly high historic rate of return on S&P utility stocks
11 (12.05 to 16.79 percent) and a similarly unrealistic equity risk premium measure
12 (7.5 to 8.9 percent). Mr. Moul attempts to defend the median as being an accepted
13 statistical measure, and in some contexts it is. However, there has been no use of it in
14 the investment literature or by investor service publications to measure either historic
15 market returns or risk premiums. (See Company response to OCA III-27.)

16 The other two measures -- geometric and arithmetic returns -- are much more
17 commonly used rate of return metrics by investors and analysts. Using the data for
18 1928-2007 from Mr. Moul's Schedule 11 (page 2 of 2), the simple average of the
19 historic geometric mean risk premium and the arithmetic mean risk premium is about
20 4.5 percent.

21 If this corrected historic (i.e., 1928-2007) risk premium of 4.5 percent is
22 combined with the recent actual single A utility bond yields of about 4.0 to
23 4.5 percent, this produces a risk premium cost of equity of 8.5 to 9.0 percent. I must
24 caution, however, that this estimate, at best, is applicable only to the S&P Utility
25 Index (regulated and unregulated operations), not necessarily to CPA.

1 Q. YOU MENTION THAT MR. MOUL TRUNCATED HIS HISTORIC RISK
2 PREMIUM DATA SERIES IN 2007. COULD DOING SO HAVE
3 MATERIALLY AFFECTED HIS RESULTS?

4 A. Yes, it appears so. Mr. Moul truncated his series in 2007 due to the asserted
5 unavailability of utility bond market returns after that year. However, in response to
6 I&E-RR-25-D he provided that information for long-term corporate bonds, which are
7 very similar to utility bonds (they generally have a slightly higher return). This data
8 response provides the following 2008 to 2011 risk premiums relative to the S&P
9 Public Utility index:
10

2008:	(37.74 %)
2009:	8.87
2010:	(6.98)
2011:	<u>1.96</u>
Average:	(8.47 %)

11 Including these post 2007 results with the 1979-2007 and 1974-2007 time periods
12 (Mr. Moul's preferred time periods for his Risk Premium Study) reduces the
13 arithmetic mean risk premiums from 6.26 percent and 6.11 percent to 4.47 percent
14 and 4.58 percent. This is the update and correction for the arithmetic mean, but
15 incorporating 2008-2011 data also would reduce the geometric mean and median in a
16 generally similar matter. Mr. Moul's next step is to adjust the downward S&P Utility
17 Index risk premium using a multiplier of 88%; i.e., $88\% \times 4.5\% = 4.0\%$.

18 Thus, merely updating Mr. Moul's study results would support a risk premium
19 value of about 4.0 percent. Assuming a single A yield of 4.5 percent and BBB yield
20 of 5.0 percent are used, the updated analysis would indicate a cost of equity of about
21 8.5 to 9.0 percent.

1 Therefore, it is clear that Mr. Moul's decision to truncate his study after 2007
2 had the effect of inflating his risk premium cost of equity estimates by a significant
3 amount.

4 **D. The CAPM Analysis**

5 Q. WHAT RESULT DID MR. MOUL OBTAIN WITH HIS CAPM STUDY?

6 A. Mr. Moul obtained a 11.13 percent estimate using the CAPM:

7
$$K_e = 3.25\% + 0.75 (9.0) + 1.14 = 11.3\%$$

8 where:

- 9
- 3.25% is the risk-free Treasury rate;
 - 0.75% is the gas company group beta (as adjusted upward by Mr. Moul);
 - 9.0% is Mr. Moul's estimate of the stock market risk premium; and
 - 1.14% is an adder to the CAPM formula to account for the small size of the gas utility companies.

10 Q. IS THIS A REALISTIC COST OF EQUITY ESTIMATE?

11 A. No. To begin with, Mr. Moul's 9.0 percent risk premium implies that investors
12 expect a long-run annual rate of return on the stock market of over 12 percent per
13 year -- an overly optimistic result out of line with actual historical returns on stocks
14 and today's expectations.

15 A recent article in the respected publication *The Economist*, in commenting on
16 corporate estimates of pension fund returns, questioned whether even 10 percent is
17 too optimistic an expectation for stocks.

18 That [a 10% return on stocks after expenses] is quite an
19 extraordinary expectation, given current market conditions. Over
20 the long run equity returns comprise the current dividend yield
21 plus dividend growth. Since the dividend yield on the S&P 500
22 is just 2.5%, that requires dividends to grow at 7.5% a year,
23

1 faster than any plausible forecast for economic growth. A rapid
2 increase in profits might be possible if the starting point was
3 sufficiently low, but American profit margins are at their highest
4 level since the mid-1960s.

5
6 The evidence suggests that companies themselves don't
7 really believe such rosy forecasts. A Duke University poll of
8 chief financial officers shows they have an average forecast for
9 equity returns over the next 10 years of 6.3 percent. (*The*
10 *Economist*, January 21, 2012, page 82)

11 As discussed earlier, I believe that a more reasonable, consensus range for the
12 equity risk premium is in the range of 5 to 8 percent. Mr. Moul's 9.0 percent exceeds
13 the upper end of this range.

14 Q. IN ADDITION TO THE OVERSTATED RISK PREMIUM, WHAT ARE
15 YOUR OTHER CONCERNS REGARDING MR. MOUL'S CAPM STUDY?

16 A. Mr. Moul uses a risk-free rate of 3.25 percent, whereas a more realistic figure at this
17 time is about 2.8 percent, as I show on page 2 of Schedule MIK-5. He employs a beta
18 statistic (the overall risk measure) of 0.75 compared to the *actual* Value Line beta
19 averaging 0.67 for his Gas Group. I understand that Mr. Moul has increased the
20 published Value Line betas to incorporate his "leverage adjustment," and I have
21 already explained why this adjustment is wrong in the context of his DCF study. In
22 this case, the leverage adjustment incorrectly adds 72 basis points to his CAPM cost
23 of equity estimate, i.e., $(0.75 - 0.67) 9.0\% = 0.72\%$.

24 Finally, there is no basis whatsoever for including a 1.14 percent adder for
25 size (which is in addition to his leverage adder). While Mr. Moul cites to certain
26 limited evidence suggesting that size could be a risk factor, he has provided no
27 evidence at all (nor am I aware that any exists) demonstrating that size is a major risk
28 factor for *utility companies*. (See Company response to OCA III-26.) Moreover, his
29 size adjustment overlooks the basic fact that CPA is merely a component of

1 NiSource, which Value Line classifies as "Large Cap," having a capitalization in
2 excess of \$14 billion. CPA, of course, contributes to NiSource's large size and
3 therefore, the alleged size-related cost of equity savings (if any). Given this absence
4 of supporting evidence, the 1.14 percent risk factor for size should be removed as
5 unsupported and incorrect.

6 Once Mr. Moul's CAPM study is corrected for these problems, it can support
7 a cost of equity no higher than about 9.0 percent, even if his very high market equity
8 premium estimate is employed.

9 E. **Comparable Earnings**

10 Q. HOW DID MR. MOUL CONDUCT HIS COMPARABLE EARNINGS
11 STUDY?

12 A. Mr. Moul selected a group of unregulated companies that appear to have relatively
13 stable operating profiles. He compiled both their historical earned returns on equity
14 and their projected equity returns. On a historical basis (and excluding companies
15 with ROE values exceeding 20 percent), their earned returns average 12.2 percent,
16 and on a projected basis they average 13.2 percent. The average of the two measures
17 is 12.7 percent. For this study, Mr. Moul does not include a leverage or CPA-specific
18 risk adder.

19 Q. IS THIS A COST OF EQUITY METHOD?

20 A. No. These are pure accounting results, and no market data is employed in the
21 analysis (other than as part of sample selection of his unregulated companies). Since
22 the analysis itself is based on accounting returns data and not market data, by
23 definition, it cannot produce a market-based cost of equity estimate.

1 Q. DO THESE ACCOUNTING FIGURES TELL US ANYTHING ABOUT
2 INVESTOR RETURN REQUIREMENTS?

3 A. No. The main problem is that these stocks normally sell at large premiums to their
4 book values. Consider the example of a non-regulated company that has an
5 accounting return on equity of 20 percent. If its shares are selling at two to three
6 times book value per share, then investors purchasing the stock at that price very
7 likely expect to realize (and therefore require) market returns much lower than that
8 20 percent. It is for this reason that the accounting ROEs by themselves are of little
9 interest to investors, and this measure is irrelevant to the "capital attraction" standard
10 of setting the fair rate of return. Investors tend to focus far more on the relationship
11 of earnings to the market price of the stock.

12 Because of this substantial premium to book value, the comparable earning
13 accounting returns would be essentially arbitrary. They would provide returns to
14 utility investors far in excess of the market requirements, which would impose
15 unnecessary harm on ratepayers.

16 Q. ARE THERE OTHER MEASUREMENT OR CONCEPTUAL PROBLEMS
17 WITH THE COMPARABLE EARNINGS METHOD, AS USED BY MR.
18 MOUL?

19 A. Yes, there are a number of other problems. The measurement of accounting returns
20 on equity for non-regulated firms frequently is distorted by accounting write-offs.
21 These write-offs would be reflected as reductions to the Company's equity balance,
22 thereby inflating the reported accounting ROE. For example, if the company has
23 \$15 of earnings and \$150 of equity, the ROE is 10 percent. If the company
24 subsequently takes a \$50 accounting write-off, the calculated ROE then becomes
25 $\$15/\$100 = 15\%$. These accounting write-offs, which have the effect of artificially

1 inflating the measured rate of return, are common and often can be very large for
2 unregulated companies but have nothing to do with CPA's regulated return
3 requirement or its cost of capital.

4 A conceptual problem with the Comparable Earnings method is that the
5 earnings reported by Mr. Moul (i.e., the numerator of the reported ROEs) can be
6 strongly influenced by the exercise of market or monopoly power. This refers to
7 profits earned by successful companies due to certain favorable circumstances that
8 exceed the competitive level of profits. Such monopoly profits in many cases could
9 be attributable to circumstances that are entirely appropriate and legal, such as patent
10 protection, unusually favorable access to key resources or a company's unique
11 product line offering. Mr. Moul has conceded that he has conducted no analysis to
12 determine whether or not the profitability results that he cites in his Comparable
13 Earnings study are from markets deemed to be fully competitive or reflect the
14 possession of market power. (Response to OCA III-21.) Profits associated with
15 market power cannot be used as a standard for either setting or evaluating CPA's or
16 any utility's fair return on equity.

17 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

18 A. Yes, it does.

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APPENDIX A
QUALIFICATIONS OF
MATTHEW I. KAHAL

MATTHEW I. KAHAL

Since 2001, Mr. Kahal has worked as an independent consulting economist, specializing in energy economics, public utility regulation and utility financial studies. Over the past three decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing, environmental compliance and utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and various aspects of regulation.

Mr. Kahal has provided expert testimony on more than 350 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory and public policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidacy - University of Maryland, completed all course work
and qualifying examinations.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal, Vice President and President).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park). Lecturer in Business and Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than thirty years' experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support

contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

Publications and Consulting Reports:

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983, (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting, (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities," (with others), in Government and Energy Policy (Richard L. Ittelag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author, (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985, (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy -- An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.) authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994. Prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.)

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).

The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005, (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005 with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

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of Matthew L. Kahal

	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-E1 May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power

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89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, <u>et. al.</u>	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls

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103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts

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117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

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146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues

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160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000 <u>et al.</u> August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915 <u>et al.</u> September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition

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189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan

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<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
203. Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204. Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205. Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206. Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207. Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208. Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209. Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210. Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211. Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212. WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213. 2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214. DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215. 00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216. Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations

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217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, <u>et al</u> July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, <u>et al</u> February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues

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<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
231. U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232. U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233. 3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234. 99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235. U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Upgrades Purchase Power
236. P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237. U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238. R-00016849C001 et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239. U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240. U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241. U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242. 8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243. U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244. 8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245. 02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return

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246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

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261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan

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<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
276. U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277. U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278. U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279. A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280. EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281. U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282. U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283. U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284. A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285. 9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286. C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287. EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288. ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289. U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290. GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

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291. R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292. 9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293. U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294. WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295. U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296. 9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297. EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298. C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299. ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300. A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301. U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302. 06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303. U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304. P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305. P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service

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	<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics

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<u>Docket Number</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>Client</u>	<u>Subject</u>
321. U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
322. U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323. U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
324. GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325. WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326. U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327. IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328. U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329. 9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330. IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331. U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332. U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333. IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334. U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335. U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract

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336. P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337. U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract
338. EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339. GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital
340. U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341. CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, <i>et al.</i>	Environmental Compliance Rate Impacts (Expert Report)
342. 4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343. U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344. U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345. U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346. M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347. GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348. D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349. U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350. U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation

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351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice/EPA	Clean Air Act Enforcement
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
361.	2:10-CV-13101 August 2010	Detroit Edison	U.S. District Court Eastern Michigan	U.S. Dept. of Justice/EPA	Clean Air Act Enforcement
362.	U-31196 August 2010	Entergy Louisiana Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase and Cost Recovery
363.	Case No. 9233 October 2010	Potomac Edison Company	Maryland	Energy Administration	Merger Issues
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default Service Plan

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365. 2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
366. U-31841 May 2011	Entergy Gulf States	Louisiana	Staff	Purchase Power Agreement
367. 11-06006 September 2011	Nevada Power	Nevada	U. S. Department of Energy	Cost of Capital
368. 9271 September 2011	Exelon/Constellation	Maryland	MD Energy Administration	Merger Savings
369. 4255 September 2011	United Water Rhode Island	Rhode Island	Division of Public Utilities	Rate of Return
370. P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default service plan
371. U-32095 November 2011	Southwestern Electric Power Company	Louisiana	Commission Staff	Wind energy contract
372. U-32031 November 2011	Entergy Gulf States Louisiana	Louisiana	Commission Staff	Purchased Power Contract
373. U-32088 January 2012	Entergy Louisiana	Louisiana	Commission Staff	Coal plant evaluation
374. R-2011-2267958 February 2012	Aqua Pa.	Pennsylvania	Office of Consumer Advocate	Cost of capital
375. P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate	Default service plan
376. U-32223 March 2012	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract and Rate Recovery
377. U-32148 March 2012	Entergy Louisiana Energy Gulf States	Louisiana	Commission Staff	RTO Membership
378. ER11080469 April 2012	Atlantic City Electric	New Jersey	Rate Counsel	Cost of capital
379. R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital

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380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan
381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Rate of Return (electric and gas)
386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**PENNSYLVANIA PUBLIC UTILITY
COMMISSION**

V.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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**DOCKET NO. R-2012-2321748
M-2012-2323645**

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 4, 2013

EXETER

ASSOCIATES, INC.
10840 Little Patuxent Parkway
Suite 300
Columbia, Maryland 21044

COLUMBIA GAS OF PENNSYLVANIA, INC.

Rate of Return Summary at
June 30, 2014

<u>Capital Type</u>	<u>Balance⁽¹⁾ (Thousands \$)</u>	<u>% of Total</u>	<u>Cost Rate</u>	<u>Weighted Cost</u>
Long-Term Debt	\$429,390	44.79%	5.64% ⁽²⁾	2.53%
Short-Term Debt	34,785	3.63	1.57 ⁽³⁾	0.06
Common Equity	<u>494,453</u>	<u>51.58</u>	<u>9.50⁽⁴⁾</u>	<u>4.90</u>
Total	\$958,628	100.00%	--	7.49%

⁽¹⁾ Source: Exhibit 400, Schedule 5, except for common equity. The common equity balance is calculated from the actual 6/30/12 balance of \$408.639 million (per the Company's latest earnings report dated November 30, 2012) increased by 10.0 percent per year with all such earnings retained (i.e., no dividend payments). Calculated as $\$408.639 \times (1.1) \times (1.1) = \$494.453$.

⁽²⁾ Exhibit 400, Schedule 6, 3 of 3. This schedule shows \$138 of planned new debt at a cost rate of 5.5 percent. This cost of new debt is overstated and I have reduced it to 5.0 percent. Correcting the cost of debt produces an annual interest expense savings of $0.5\% \times \$138 \text{ million} = \$0.69 \text{ million}$. This reduces total interest expense from \$24.914 million to \$24.224 million. The corrected cost of long-term debt = $\$24.224 / \$429.39 = 5.64\%$.

⁽³⁾ Exhibit 400, Schedule 6, 1 of 3.

⁽⁴⁾ Schedule MIK-4, page 1 of 5 and testimony (OCA Statement No. 2).

COLUMBIA GAS OF PENNSYLVANIA, INC.

Trends in Capital Costs

	<u>Annualized Inflation (CPI)</u>	<u>10-Year Treasury Yield</u>	<u>3-Month Treasury Yield</u>	<u>Single A Utility Yield</u>
2001	2.9%	5.0%	3.5%	7.8%
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2
2005	3.4	4.3	3.0	5.6
2006	2.5	4.8	4.8	6.1
2007	2.8	4.6	4.5	6.3
2008	3.8	3.4	1.6	6.5
2009	(0.4)	3.2	0.2	6.0
2010	1.6	3.2	0.1	5.5
2011	3.1	2.8	0.0	5.1

COLUMBIA GAS OF PENNSYLVANIA, INC.**U.S. Historic Trends in Capital Costs
(Continued)**

	<u>Annualized Inflation (CPI)</u>	<u>10-Year Treasury Yield</u>	<u>3-Month Treasury Yield</u>	<u>Single A Utility Yield</u>
<u>2007</u>				
January	2.1%	4.8%	5.1%	6.0%
February	2.4	4.7	5.2	5.9
March	2.8	4.6	5.1	5.9
April	2.6	4.7	5.0	6.0
May	2.7	4.8	5.0	6.0
June	2.7	5.1	5.0	6.3
July	2.4	5.0	5.0	6.3
August	2.0	4.7	4.3	6.2
September	2.8	4.5	4.0	6.2
October	3.5	4.5	4.0	6.1
November	4.3	4.2	3.4	6.0
December	4.1	4.1	3.1	6.2
<u>2008</u>				
January	4.3%	3.7%	2.8%	6.0%
February	4.0	3.7	2.2	6.2
March	4.0	3.5	1.3	6.2
April	3.9	3.7	1.3	6.3
May	4.2	3.9	1.8	6.3
June	5.0	4.1	1.9	6.4
July	5.6	4.0	1.7	6.4
August	5.4	3.9	1.8	6.4
September	4.9	3.7	1.2	6.5
October	3.7	3.8	0.7	7.6
November	1.1	3.5	0.2	7.6
December	0.1	2.4	0.0	6.5

COLUMBIA GAS OF PENNSYLVANIA, INC.

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
<u>2009</u>				
January	0.0%	2.5%	0.1%	6.4%
February	0.2	2.9	0.3	6.3
March	(0.4)	2.8	0.2	6.4
April	(0.7)	2.9	0.2	6.5
May	(1.3)	2.9	0.2	6.5
June	(1.4)	3.7	0.2	6.2
July	(2.1)	3.6	0.2	6.0
August	(1.5)	3.6	0.2	5.7
September	(1.3)	3.4	0.1	5.5
October	(0.2)	3.4	0.1	5.6
November	1.8	3.4	0.1	5.6
December	2.5	3.6	0.1	5.8
<u>2010</u>				
January	2.6%	3.7%	0.1%	5.8%
February	2.1	3.7	0.1	5.9
March	2.3	3.7	0.2	5.8
April	2.2	3.9	0.2	5.8
May	2.0	3.4	0.2	5.5
June	1.1	3.2	0.1	5.5
July	1.2	3.0	0.2	5.3
August	1.1	2.7	0.2	5.0
September	1.1	2.7	0.2	5.0
October	1.2	2.5	0.1	5.1
November	1.1	2.8	0.1	5.4
December	1.2	3.3	0.1	5.6

COLUMBIA GAS OF PENNSYLVANIA, INC.**U.S. Historic Trends in Capital Costs
(Continued)**

	<u>Annualized Inflation (CPI)</u>	<u>10-Year Treasury Yield</u>	<u>3-Month Treasury Yield</u>	<u>Single A Utility Yield</u>
<u>2011</u>				
January	1.6%	3.4%	0.1%	5.6%
February	2.1	3.6	0.1	5.7
March	2.7	3.4	0.1	5.6
April	2.2	3.5	0.1	5.6
May	3.6	3.2	0.0	5.3
June	3.6	3.0	0.0	5.3
July	3.6	3.0	0.0	5.3
August	3.8	2.3	0.0	4.7
September	3.9	2.0	0.0	4.5
October	3.5	2.2	0.0	4.5
November	3.0	2.0	0.0	4.3
December	3.0	2.0	0.0	4.3
<u>2012</u>				
January	2.9	2.0	0.0	4.3
February	2.9	2.0	0.0	4.4
March	2.7	2.2	0.1	4.5
April	2.3	2.1	0.1	4.4
May	1.7	1.8	0.1	4.2
June	1.7	1.6	0.1	4.1
July	1.4	1.5	0.1	3.9
August	1.7	1.7	0.1	4.0
September	2.0	1.7	0.1	4.0
October	2.2	1.8	0.1	3.9
November	--	1.7	0.1	3.8

Source: *Economic Report of the President, Mergent's Bond Record,*
Federal Reserve Statistical Release (H.15), Consumer Price Index Summary
 (BLS)

COLUMBIA GAS OF PENNSYLVANIA

Listing of the Gas Utility Proxy Companies

<u>Company</u>	<u>Safety Rating</u>	<u>Financial Strength</u>	<u>Beta</u>	<u>2011 Common Equity Ratio*</u>
1. AGL Resources	1	A	0.75	48.0%
2. Atmos Energy	2	B++	0.70	50.6%
3. LaClede Group	2	B++	0.55	61.1%
4. New Jersey Resources	1	A	0.65	64.5%
5. NW Natural Gas	1	A	0.55	52.7%
6. Piedmont Natural	2	B++	0.65	59.6%
7. South Jersey Ind.	2	B++	0.65	59.5%
8. Southwest Gas	3	B	0.75	56.8%
9. WGL Corporation	<u>1</u>	<u>A</u>	<u>0.65</u>	<u>66.2%</u>
Average	1.7	--	0.66	57.7%

* The common equity ratio excludes short-term debt (and current maturities of long-term debt).
Actual 2011 equity ratio including short-term debt and current maturities averages 49.1 percent.

Source: *Value Line Investment Survey*, December 7, 2012.

COLUMBIA GAS OF PENNSYLVANIA

DCF Summary for
Gas Distribution Proxy Group

1.	Dividend Yield (January - June 2012)	3.74% ⁽¹⁾
2.	Adjusted Yield ((1) x 1.0275)	3.8%
3.	Long-Term Growth Rate	5.0 - 6.0% ⁽²⁾
4.	Total Return ((2) + (3))	8.8 - 9.8%
5.	Flotation Expense	0.0%
6.	Cost of Equity ((4) + (5))	8.8 - 9.8%
7.	Midpoint for Proxy Group	9.3%
8.	CPA Risk Consideration	0.0 - 0.4 ⁽³⁾
9.	Final Range w/Potential Risk Adjustment	8.8 - 10.2%
10.	Midpoint and Recommendation for CPA	9.5%

⁽¹⁾ Schedule MIK-4, page 2 of 5.

⁽²⁾ Schedule MIK-4, pages 3 of 5, 4 of 5 and 5 of 5.

⁽³⁾ Per testimony, the risk adjustment should only be considered if the OCA position on residential rate design in this case is adopted. If the OCA's rate design position is not adopted, then my recommendation is 9.3 percent.

COLUMBIA GAS OF PENNSYLVANIA

Dividend Yields for Gas Distribution Proxy Group (April - September 2012)

	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>Average</u>
1. AGL Resources	4.6%	4.9%	4.7%	4.5%	4.6%	4.5%	4.63%
2. Atmos Energy	4.2%	4.2%	3.9%	3.8%	3.9%	3.9%	3.98%
3. LaClede Group	4.2%	4.4%	4.2%	4.0%	3.9%	3.9%	4.10%
4. New Jersey Resources	3.5%	3.6%	3.5%	3.3%	3.4%	3.5%	3.47%
5. Northwest Natural Gas	3.9%	3.8%	3.7%	3.7%	3.6%	3.6%	3.72%
6. Piedmont Natural	3.9%	4.0%	3.7%	3.8%	3.8%	3.7%	3.82%
7. South Jersey Ind.	3.3%	3.3%	3.2%	3.0%	3.2%	3.0%	3.17%
8. Southwest Gas	2.8%	2.8%	2.7%	2.6%	2.8%	2.7%	2.73%
9. WGL Corporation	<u>4.0%</u>	<u>4.1%</u>	<u>4.0%</u>	<u>4.0%</u>	<u>4.1%</u>	<u>4.0%</u>	<u>4.03%</u>
Average	3.82%	3.90%	3.73%	3.63%	3.70%	3.64%	3.74%

Source: S&P *Stock Guide*, May - October 2012.

COLUMBIA GAS OF PENNSYLVANIA

Projection of Earnings per Share Five-Year Growth Rates for the Gas Distribution Proxy Group

	<u>Company</u>	<u>Value Line</u>	<u>Yahoo</u>	<u>MSN</u>	<u>Reuters</u>	<u>CNN</u>	<u>Average</u>
1.	AGL Resources	6.0%	(5.7%)*	4.4%	5.03%	4.0%	4.86%
2.	Atmos Energy	4.0%	6.00%	6.0%	5.67%	6.0%	5.53%
3.	LaClede Group	3.0%	5.30%	3.0%	5.00%	4.0%	4.06%
4.	New Jersey Resources	5.5%	2.70%	3.4%	3.85%	3.0%	3.69%
5.	Northwest Natural Gas	3.0%	4.50%	4.2%	4.17%	3.75%	3.92%
6.	Piedmont Natural	2.5%	5.35%	5.2%	5.35%	5.85%	4.85%
7.	South Jersey Ind.	9.0%	6.00%	6.0%	7.00%	8.0%	7.20%
8.	Southwest Gas	9.0%	4.05%	5.0%	2.53%	6.0%	5.32%
9.	WGL Corporation	<u>2.5%</u>	<u>5.60%</u>	<u>5.3%</u>	<u>5.60%</u>	<u>4.3%</u>	<u>4.66%</u>
	Average	4.94%	4.94%	4.72%	4.91%	4.99%	4.90%

Sources: *Value Line Investment Survey*, December 7, 2012. YahooFinance.com, MSNMoney.com, CNNMoney.com, Reuters.com, public websites, December 2012.

* The large, negative growth rate published by YahooFinance.com appears to be anomalous and inconsistent with other published sources. For that reason, it is excluded from the reported averages.

COLUMBIA GAS OF PENNSYLVANIA

Other Value Line Measure of Growth for the Gas Distribution Proxy Group

	<u>Company</u>	<u>Dividend Per Share</u>	<u>Book Value Per Share</u>	<u>Earnings Retention</u>
1.	AGL Resources	1.5%	5.0%	6.5%
2.	Atmos Energy	1.5%	6.0%	3.5%
3.	LaClede Group	2.5%	4.5%	4.5%
4.	New Jersey Resources	4.0%	5.5%	7.5%
5.	Northwest Natural Gas	2.5%	1.0%	4.0%
6.	Piedmont Natural	3.5%	1.5%	3.5%
7.	South Jersey Ind.	9.0%	6.0%	7.5%
8.	Southwest Gas	8.0%	6.0%	6.0%
9.	WGL Corporation	<u>2.5%</u>	<u>4.0%</u>	<u>3.5%</u>
	Average	3.89%	4.39%	5.17%

Source: *Value Line Investment Survey*, December 7, 2012. The earnings retention figures are projections for 2015-2017.

COLUMBIA GAS OF PENNSYLVANIA

Fundamental Growth Rate Analysis for Gas Distribution Proxy Group

	<u>Shares 2011-2016⁽¹⁾</u>	<u>% Premium⁽²⁾</u>	<u>sv⁽³⁾</u>	<u>br⁽⁴⁾</u>	<u>sv + br</u>
1. AGL Resources	0.00%	24.3%	0.0%	6.5%	6.5%
2. Atmos Energy	2.67%	32.7%	0.9%	3.5%	4.4%
3. LaClede Group	0.94%	50.0%	0.5%	4.5%	5.0%
4. New Jersey Resources	Negative	NA	0.0%	7.5%	7.5%
5. Northwest Natural Gas	0.91%	60.6%	0.6%	4.0%	4.6%
6. Piedmont Natural	Negative	NA	0.0%	3.5%	3.5%
7. South Jersey Ind.	3.57%	112.9%	4.0%	7.5%	11.5%
8. Southwest Gas	1.70%	47.8%	0.8%	6.0%	6.8%
9. WGL Corporation	<u>0.31%</u>	<u>52.8%</u>	<u>0.2%</u>	<u>3.5%</u>	<u>3.7%</u>
Average			0.77%	5.17%	5.93%

⁽¹⁾ Projected growth rate in shares outstanding, 2011-2016.

⁽²⁾ % Premium of share price ("Recent Price") over 2011 Book Value per share.

⁽³⁾ sv is growth rate in shares x % premium.

⁽⁴⁾ br is Value Line's projection as of 2015-2017.

Source: *Value Line Investment Survey*, December 7, 2012.

COLUMBIA GAS OF PENNSYLVANIA

Capital Asset Pricing Model Study Illustrative Calculations

A. Model Specification

$K_e = R_F + \beta (R_m - R_F)$, where

K_e = cost of equity

R_F = return on risk free asset

R_m = expected stock market return

B. Data Inputs

R_F = 2.8% (Treasury bond yield for the most recent six months, see page 2 of 2)

R_m = 7.8 – 10.8% (equates to equity risk premium of 5.0 - 8.0%)

Beta = 0.66 (Per Value Line, see Schedule MIK-3)

C. Model Calculations

Low end: $K_e = 2.8\% + 0.66 (5.0) = 6.1\%$

Midpoint: $K_e = 2.8\% + 0.66 (6.5) = 7.1\%$

Upper End: $K_e = 2.8\% + 0.66 (8.0) = 8.1\%$

High Sensitivity: $K_e = 2.8\% + 0.66 (9.0) = 8.7\%$

COLUMBIA GAS OF PENNSYLVANIA

Long-Term Treasury Yields
(June - November 2012)

<u>Month</u>	<u>30-Year</u>	<u>20-Year</u>	<u>10-Year</u>
June	2.70%	2.31%	1.62%
July	2.59	2.22	1.53
August	2.77	2.40	1.68
September	2.88	2.49	1.72
October	2.90	2.51	1.75
November	<u>2.80</u>	<u>2.39</u>	<u>1.65</u>
Average	2.77%	2.39%	1.66%

Source: Federal Reserve, "Statistical Release," Table H.15, July-December 2012

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

**PENNSYLVANIA PUBLIC UTILITY
COMMISSION**

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

**DOCKET NOS. R-2012-2321748
M-2012-2323645**

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

FEBRUARY 8, 2013

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EXETER

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

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I. OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this matter by the Office of Consumer Advocate (OCA). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. On January 4, 2013, I submitted Direct Testimony on behalf of the OCA on cost of capital for Columbia Gas of Pennsylvania ("CPA" or "the Company").

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I am submitting Surrebuttal Testimony at this time to respond to the Rebuttal Testimony of Mr. Paul Moul filed by CPA on January 28, 2013 (Columbia Statement No. 110-R). His Rebuttal Testimony both defends his own Direct Testimony from the criticisms set forth in my Direct Testimony and disputes the CPA cost of capital analysis and recommendations in my Direct Testimony. Please note that the cost of capital issues in dispute pertain to capital structure, cost of debt and cost of equity.

Q. BEFORE TURNING TO YOUR RESPONSE TO MR. MOUL, PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My January 4, 2013, Direct Testimony recommends a return on rate base of 7.49 percent. The following table is a concise comparison of my recommended cost of capital components as compared to those of Mr. Moul.

	Kahal	Moul
Equity Ratio	51.58%	52.32%
Short-term Debt Cost	1.57%	1.85%
Long-term Debt Cost	5.64%	5.81%
Equity Return	9.50%	11.25%

1 My equity cost rate is based primarily on my Gas Group DCF study, giving
2 some recognition to a CPA risk adjustment relative to the Gas Group. However, if
3 one of the Company's residential rate design proposals is adopted (which would
4 reduce the Company's operating risk), then my Gas Group DCF midpoint of 9.3
5 percent (with no recognition of any upward risk adjustment) is the appropriate
6 authorized return on equity. That is, my 9.5 percent recommendation is based upon
7 the assumption that the OCA's position on residential rate design is adopted.

8 Q. WHAT ARE THE PRINCIPAL AREAS OF DISPUTE IN MR. MOUL'S
9 REBUTTAL TESTIMONY?

10 A. As Mr. Moul correctly states, the greatest area of disagreement concerns the common
11 equity cost rate, i.e., his 11.25 percent as compared to my 9.5 percent. The majority
12 of his Rebuttal Testimony is devoted to that issue.

13 The differences in capital structure and cost of debt are relatively small. The
14 capital structure issue concerns the accuracy of the Company's retained earnings
15 projection, which extends to June 2014. In my opinion, the Company assumes an
16 overly optimistic increase over the next two years in retained earnings, which I have
17 corrected in my Direct Testimony.

18 The cost of debt is more problematic. Mr. Moul assumes that CPA's new debt
19 issues, which are actually affiliate transactions with a NiSource financing subsidiary,
20 will carry a very high cost rate. While this may be true, it is attributable to the
21 affiliate's (and NiSource parent) relatively weak BBB- credit rating. In my opinion,
22 this cost premium is improper, and it should not be flowed through to CPA
23 ratepayers.

1 Q. BASED ON YOUR REVIEW OF MR. MOUL'S REBUTTAL
2 TESTIMONY, ARE YOU REVISING ANY RECOMMENDATIONS IN
3 YOUR DIRECT TESTIMONY?

4 A. No, I am not. Mr. Moul has not provided any new information, analyses or
5 arguments that would warrant changing the findings and recommendations in my
6 Direct Testimony.

7 Q. HAS MR. MOUL PROVIDED A COST OF CAPITAL UPDATE?

8 A. Mr. Moul slightly modified the fully forecasted future rate year cost of debt but
9 otherwise made no change to his overall rate of return recommendation of 8.52
10 percent. He did not provide an updated cost of equity study, and he continues to
11 recommend a 11.25 percent ROE award.

12

1 **II. CAPITAL STRUCTURE AND COST OF DEBT**

2 Q. WHAT IS THE CAPITAL STRUCTURE DISPUTE IN THIS CASE?

3 A. Mr. Moul proposes using a CPA projected capital structure at June 30, 2014, which
4 requires developing a forecast of the Company's retained earnings balance almost
5 two years hence. Such a forecast of earnings is inherently speculative since a number
6 of factors can influence earnings. This retained earnings forecast was never
7 explained or substantiated in Mr. Moul's Direct Testimony, nor was he able to
8 provide the basis for it (i.e., supporting analysis) in response to OCA and Bureau of
9 Investigation and Enforcement ("I&E") data requests. In my Direct Testimony, I
10 stated that the Company's assumed earnings growth appeared to be overly optimistic,
11 with earnings equivalent to nearly a 12 percent earned return on equity for those two
12 years. By comparison, the most recent earnings report for the Company filed with the
13 Commission indicated an earned return on equity of 9.3 percent (12 months ending
14 September 30, 2012). I therefore recalculated the June 30, 2014 retained earnings
15 balance assuming a more reasonable 10 percent earned return on equity for the two
16 years, or a figure somewhat higher than my 9.5 percent recommendation. Note that
17 both Mr. Moul and I assumed that CPA would pay no dividends to its parent over the
18 two years, an assumption which is not precisely correct.

19 Q. HOW DOES MR. MOUL RESPOND IN REBUTTAL TESTIMONY?

20 A. In his Rebuttal Testimony, Mr. Moul still does not explain how he developed his June
21 30, 2014 projection of retained earnings, but he tries to argue that I have overstated
22 the problem. He seems to suggest that his projection is actually consistent with an
23 earned return on equity of around 11 percent (when measured on average equity
24 rather than beginning year equity), returns that he views as "entirely achievable" for
25 CPA based on its past history.

1 Q. IS THE DISCUSSION IN MR. MOUL'S REBUTTAL TESTIMONY
2 CORRECT?

3 A. Mr. Moul's description of my analysis is inaccurate and ignores the information set
4 forth in my Direct Testimony and Schedule MIK-1. He asserts that my analysis was
5 based on a starting point equity balance of \$410 million as of May 2012 and
6 employed a 13-month year (which needs to be adjusted to 12 months for return on
7 equity purposes). This is not correct. I clearly stated that my starting point of was the
8 Company's **actual** June 30, 2012 balance of \$408.6 million. Over this two-year (24-
9 month) time period, Mr. Moul is therefore assuming about \$100 million in retained
10 earnings growth, which translate to roughly an 11 percent return on equity when
11 expressed on an average equity (as opposed to a beginning year equity basis).

12 Mr. Moul, of course, is recommending in this case a return on equity for CPA
13 of 11.25 percent. Thus, his capital structure (i.e., common equity balance) projection
14 may be reasonable if his 11.25 percent return on equity or something close to it is
15 adopted by the Commission in this case, but not if a significantly lower return on
16 equity (such as my 9.5 percent) is adopted.

17 Q. PLEASE SUMMARIZE YOUR POSITION ON THIS ISSUE.

18 A. Mr. Moul's equity balance projection at June 30, 2014 is both speculative and overly
19 optimistic. In my Direct Testimony, I have slightly reduced his retained earnings
20 projection to be more in line with both my cost of equity finding and the Company's
21 recent earnings experience. Moreover, the equity ratio that I am recommending is
22 more consistent with the Company's recent actual equity ratio and the Gas Group
23 average equity ratio, as compared to Mr. Moul's projection.

1 Q. YOU HAVE DISPUTED THE COMPANY'S COST OF DEBT ESTIMATE.
2 PLEASE EXPLAIN WHY.

3 A. The Company projects several new long-term debt issues between the rate case filing
4 and June 30, 2014, with cost rates for the new debt averaging about 5.7 percent. This
5 pricing is dictated to CPA by its NiSource financing affiliate, not the actual capital
6 market, since CPA obtains the debt capital from its affiliate. The 5.7 percent estimate
7 is much higher than the actual cost rates for long-term triple B utility debt, which in
8 recent months has averaged below 5.0 percent. I cite below the Baa cost rate for
9 utility debt for the last six months of 2012 as reported in Moody's *Bond Record*,
10 January 2013.

July 2012	4.85%
August	4.88
September	4.81
October	4.54
November	4.42
December	4.56

11 Based on these trends, I stated in Direct Testimony that 5.0 percent would be a more
12 reasonable cost rate for the new debt and that his 5.7 percent is clearly too high.

13 The higher debt cost rate proposed by the Company may be due to the fact
14 that the financing affiliate and NiSource itself have an unusually weak credit rating of
15 BBB-, which is barely investment grade. It is no mystery why the credit rating is so
16 weak. As I noted in Direct Testimony (and Mr. Moul confirmed), NiSource is highly
17 leveraged with only about a 40 percent equity ratio. While this is a very inexpensive
18 capital structure (as compared to CPA's), it does contribute to a higher cost of debt –
19 hence the relatively expensive 5.7 percent cost rate estimate.

20 This cost rate, however, is inherently unfair to CPA customers. They must
21 pay rates reflecting a robust 52 percent common equity ratio, but they must pay for
22 debt costs as if the equity ratio is a relatively weak 40 percent – the worst of both

1 worlds. Moreover, this poor credit rating (resulting from NiSource's high degree of
2 leverage) is also the basis for Mr. Moul's 0.76 percent cost of equity risk adder. CPA
3 customers should not pay for either the debt or equity cost rate premium caused by
4 NiSource's weak capital structure. This is inconsistent.

5 Q. WHAT IS MR. MOUL'S RESPONSE IN HIS REBUTTAL TESTIMONY?

6 A. At pages 7-8, he simply argues that the 5.7 percent cost for the new debt is correctly
7 calculated and that CPA benefits from being part of NiSource. He further argues that
8 the NiSource credit rating is not due solely to its weak capital structure. He also
9 argues that CPA "would not have high credit quality on its own."

10 Q. ARE HIS ARGUMENTS PERSUASIVE?

11 A. No, they are both irrelevant and lack factual foundation. There is no question that
12 NiSource's highly leveraged capital structure and financing policies go a long way in
13 explaining its weak credit rating (and high cost of debt). There simply is no other
14 explanation since NiSource's business profile is viewed by credit rating agencies as
15 relatively favorable and low risk. Mr. Moul cites no evidence in support of his
16 assertion. Despite the fact that CPA does not have a credit rating, Mr. Moul asserts
17 its "stand-alone" credit quality would be weak. He has absolutely no basis for that
18 assertion and provides no supporting data. To the contrary, given CPA's strong
19 balance sheet and low business risk, its credit quality would be relatively strong.

20 Finally, the issue is not whether – on balance – CPA benefits or does not
21 benefit from being a NiSource subsidiary. The issue is whether an affiliate
22 transaction for new long-term debt is properly priced. It is not, and Mr. Moul has no
23 support for his assertion that it is reasonable.

24 The bottom line is that CPA ratepayers must pay above-market cost rates due
25 to NiSource's weak credit quality, and this is improper. My repricing of the new

1 long-term debt to 5.0 percent and the lowering of the proposed 1.85 percent short-
2 term debt cost rate to 1.57 percent are reasonable and reflective of CPA's strong
3 financial position.
4

1 **III. COST OF EQUITY**

2 Q. DOES MR. MOUL AGREE WITH YOUR GAS GROUP DCF STUDY?

3 A. No, he proposes some modifications to it that increase the midpoint DCF result from
4 9.3 to 10.56 percent. These modifications are as follows:

5 (1) He proposes some calculation refinements to my “fundamental” DCF growth
6 rate (which I provided on Schedule MIK-4, page 5 of 5), which increases it
7 slightly from 5.9 to 6.1 percent.

8 (2) He restates my DCF study by selectively using only the higher fundamental
9 growth rate (modified to be 6.1 percent) and ignoring my lower securities
10 analysts’ growth rate of 4.9 percent. My study gave equal weight to both
11 sources of growth rates, and Mr. Moul’s own DCF study is based on the
12 securities analysts’ growth rates.

13 (3) Mr. Moul adds in his “leverage” adjustment of 0.64 percent.

14 His end result restatement is a revised DCF study as follows:

15
$$K_e = 3.8\% + 6.1\% + 0.64\% = 10.56\%$$

16 Q. IS THIS DCF STUDY RESTATEMENT VALID?

17 A. No, it is not. While I do not agree with Mr. Moul’s calculation refinements to my
18 fundamental growth rate, increasing it from 5.9 to 6.1 percent, the change is not
19 material. Since my practice is to give the fundamental and the (4.9 percent) securities
20 analysts’ growth rates equal weight, my growth rate evidence for the Gas Group
21 averages 5.5 percent (i.e., $(4.9 + 6.1)/2 = 5.5\%$), not 6.1 percent.

22
$$K_e = 3.8\% + 5.5\% = 9.3\%$$

1 Mr. Moul's exclusive use of the revised fundamental growth rate and assigning zero
2 weight to the securities analysts' growth rates is merely an exercise in selectively
3 latching onto the highest growth rate he can find. His revision to my fundamental
4 growth rate has no material effect on my Gas Group DCF midpoint result.

5 Q. WHAT IS MR. MOUL'S OWN GAS GROUP DCF GROWTH RATE?

6 A. He uses a growth rate of 5.25 percent in his own study, not 6.1 percent.

7 Q. MR. MOUL'S RESTATEMENT OF YOUR DCF STUDY ALSO
8 INCLUDES HIS 0.64 PERCENT LEVERAGE ADJUSTMENT. IS THIS
9 PROPER?

10 A. No, as I explained in my Direct Testimony, the leverage adjustment is an extraneous
11 adder that has nothing whatsoever to do with the Gas Group DCF study. While the
12 degree of leverage that a company has can affect its investment risk (along with other
13 factors), this is already fully captured in that company's stock price, its dividend yield
14 and therefore, in the proper application of the standard DCF formula. That formula
15 does not include this leverage adjustment.

16 The next question is whether the leverage adjustment is needed for CPA's cost
17 of equity as compared to the Gas Group average. Clearly it is not since CPA's debt
18 leverage is roughly the same as the Gas Group average, a fact that Mr. Moul
19 recognizes. Thus, the leverage adjustment is unrelated to the CPA versus Gas Group
20 leverage.

21 Q. DOES MR. MOUL DEFEND HIS LEVERAGE ADJUSTMENT IN HIS
22 REBUTTAL TESTIMONY?

23 A. Yes, at pages 24-30. However, I see little that is substantively new in this defense as
24 compared to the discussion in his Direct Testimony. At page 24, he justifies this
25 adder by stating:

1
2 to make the DCF results relevant in the
3 ratemaking context, the market-derived cost
4 rate cannot be used without modification.

5 This statement effectively concedes that his leverage adjustment is not part of the
6 conventional DCF method, and he therefore asserts the standard DCF (Gas Group)
7 results require an artificial "modification." This statement further concedes that while
8 the DCF formula produces "the market-derived cost rate," an adder to what capital
9 markets require is warranted by "ratemaking" considerations.

10 Q. WHAT IS YOUR RESPONSE TO THIS EXPLANATION?

11 A. I believe that Mr. Moul and I would agree that a fair return on equity should
12 compensate investors for the return that investors require. However, Mr. Moul would
13 go further and provide an adder – for ratemaking purposes – that results in a return
14 even greater than what investors require. To the contrary, the fair return should not
15 exceed market and investor requirements because doing so is not needed to meet the
16 capital attraction standard, would inefficiently sanction monopoly profits for utility
17 service and would overcharge ratepayers.

18 The leverage adjustment is indisputably not part of the cost of equity and is
19 not an acceptable adjustment factor. There simply is no defect with ratemaking that
20 the leverage adjustment must cure.

21 Q. MR. MOUL ALSO HAS PROPOSED A CPA RISK ADDER OF 0.76
22 PERCENT, WHICH YOU AND I&E WITNESS SEARS HAVE
23 CONTESTED. DOES HE ADDRESS THIS IN HIS REBUTTAL
24 TESTIMONY?

25 A. Yes, he discusses it briefly at pages 30-31, but he provides no new evidence. He does
26 explain that the 0.76 percent is quantified based on the NiSource relatively weak
27 BBB- credit rating as compared to the Gas Group A – average credit rating.

1 Q. WHAT IS YOUR RESPONSE?

2 A. As I explained earlier, the BBB- credit rating is attributable to NiSource's high degree
3 of debt leverage (i.e., 60 percent debt), a characteristic not shared by CPA. While
4 CPA does not have its own credit rating, given its strong balance sheet, strong
5 financial performance, very favorable business risk profile and the availability of the
6 DSIC mechanism, it is clearly quite credit worthy. That said, I do not have an
7 adequate factual basis for affirmatively asserting that CPA would be rated low single
8 A. For that reason, and to be conservative, I recommended consideration of a risk
9 adder range of 0.0 to 0.4 percent, which recognizes the possibility, but not the
10 certainty, that a risk adder relative to the Gas Group may be warranted.

11 In summary, Mr. Moul's risk adder, based on the NiSource credit rating, is far
12 too large, and there is a plausible argument that no risk adder is needed at all. The
13 0.76 percent premium is simply not applicable to CPA. If a risk adder is warranted at
14 all, it should be much smaller than Mr. Moul's estimate.

15 Q. DOES MR. MOUL'S REBUTTAL TESTIMONY ALSO ADDRESS
16 CRITICISMS OF HIS CAPM, RISK PREMIUM AND COMPARABLE
17 EARNINGS STUDIES?

18 A. Yes. However, his responses to my criticisms are relatively brief and contain little
19 that is new in the way of analysis or information. Moreover, this Commission has
20 traditionally relied primarily on the DCF to establish the cost of equity, not these
21 other methods.

22 With regard to the CAPM, Mr. Moul seeks to support his risk premium value
23 of 9.0 percent by reference to historical returns data, an S&P 500 DCF study and
24 what he purports to be Value Line's estimate of the overall stock market return. The
25 Value Line figure, an outlandishly high rate of return of 13.9 percent, does not

1 measure the overall stock market return at all. It certainly is not Value Line's
2 estimate of the overall stock market rate of return. Rather, it reflects Mr. Moul's
3 estimate of the return potential for the median company in the Value Line data base,
4 not the expected rate of return for the broad market index such as the S&P 500. Once
5 the improper Value Line figure is removed, Mr. Moul's evidence supports a risk
6 premium below the top end of the Brealy and Myers 5.0 to 8.0 percent range that I
7 referenced in my Direct Testimony.

8 Mr. Moul also defends his 1.14 percent "size" adder in his CAPM. This adder
9 is controversial and to my knowledge has received little or no regulatory acceptance.
10 Moreover, even if a size adder is considered valid in a general sense, it is not
11 applicable to CPA (which is a subsidiary of a large cap company). However, even if
12 one were to accept the use of a risk premium value of 8.0 percent (based on Mr.
13 Moul's evidence excluding the faulty Value Line figure) and his 1.14 percent size
14 adder, the CAPM estimate would fall within my DCF range. Using the Gas Group
15 beta of 0.66, a high side 8.0 percent risk premium value, a recent 3.0 percent long-
16 term Treasury bond rate and the 1.14 percent size adder, I obtain:

$$17 \quad K_e = 3.0\% + 0.66 (8.0\%) + 1.14\% = 9.4\%$$

18 Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S DISCUSSION OF HIS
19 RISK PREMIUM STUDY?

20 A. Mr. Moul responds to my "complaint" that he relied upon the "median" measure in
21 developing his historically-based risk premium. He states that the median is a
22 statistical measure often used in financial publications.

23 I am not "complaining" about Mr. Moul's use of the median, and I
24 acknowledge that median is often used in other aspects of financial analysis to
25 estimate the central tendency of an array of data. Rather, my point is much more

1 specific. The median is **never** used in financial analysis as a metric to determine or
2 state the historical average rate of return on a financial asset, nor is it ever used to
3 measure the (historical) risk premium. Mr. Moul could not name a single published
4 study that uses the median for this purpose.

5 My larger criticism in Direct Testimony was that he truncated his historical
6 risk premium study in 2007, and had he updated it through 2011, his risk premium
7 results and cost of equity would be much lower, regardless of which statistical
8 measure is used. Mr. Moul could provide no substantive response to that criticism.

9 Q. IN YOUR DIRECT TESTIMONY YOU SET FORTH SEVERAL
10 ANALYTICAL CRITICISMS FOR MR. MOUL'S COMPARABLE
11 EARNINGS STUDY. DID HE RESPOND TO THOSE SPECIFIC
12 CRITICISMS?

13 A. No, he did not. At pages 42-44, he merely provides a very general discussion as to
14 why the Comparable Earnings method is relevant and useful to the regulatory task of
15 setting a utility's fair return. My Direct Testimony observed that the Comparable
16 Earnings method, as used by Mr. Moul, does not measure the cost of equity – that is,
17 the market requirement for CPA. I also noted that Mr. Moul's study method of
18 reporting accounting earnings is distorted in several respects and therefore, is not
19 useful. Mr. Moul did not respond to these measurement criticisms, and he seems to
20 concede that Comparable Earnings is not a true cost of equity method (at page 43).

21 In defending the Comparable Earnings method, he states that "regulation
22 should emulate results obtained by firms operating in competitive markets" (at page
23 42). In a sense, cost-based regulation is consistent with the competitive ideal because
24 the competitive ideal does not produce monopoly profits. However, part of the
25 problem with Mr. Moul's analysis is that he never demonstrates, and he cannot

1 demonstrate, that his group of companies in his study actually operate in competitive
2 markets or do not earn monopoly profits. Without such assurance, his analysis cannot
3 meet his own criterion of “emulating the competitive market.”

4 Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

5 A. Yes, it does.

6 165753

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket Nos. R-2012-2321748
	:	M-2012-2323645
	:	
Columbia Gas of Pennsylvania, Inc.	:	

DIRECT TESTIMONY AND EXHIBITS

OF

GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 4, 2013

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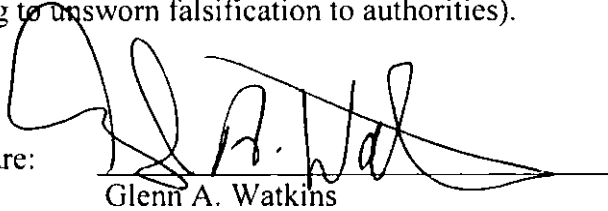
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts above set forth in my Direct Testimony (OCA Statement No. 3), Rebuttal Testimony (OCA Statement No. 3-R) and Surrebuttal Testimony (OCA Statement 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:


Glenn A. Watkins

Consultant Address: 9030 Stony Point Parkway
Suite 580
Richmond, VA 23235

DATED: Feb. 11, 2013

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1 **I. INTRODUCTION**

2
3 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 A. My name is Glenn A. Watkins. My business address is 9030 Stony Point
5 Parkway, Suite 580, Richmond, VA 23235.

6
7 **Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?**

8 A. I am a Principal and Senior Economist with Technical Associates, Inc., which is
9 an economics and financial consulting firm with offices in Richmond, Virginia. Except
10 for a six month period during 1987 in which I was employed by Old Dominion Electric
11 Cooperative, as its forecasting and rate economist, I have been employed by Technical
12 Associates continuously since 1980.

13 During my career at Technical Associates, I have conducted marginal and
14 embedded cost of service, rate design, cost of capital, revenue requirement, and load
15 forecasting studies involving numerous electric, gas, water/wastewater, and telephone
16 utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia,
17 Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey,
18 North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington,
19 and West Virginia. A more complete description of my education and experience is
20 provided in my Schedule GAW-1.

21
22 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

23 A. Technical Associates, Inc. has been retained by the Pennsylvania Office of
24 Consumer Advocate ("OCA") to evaluate the reasonableness of Columbia Gas of
25 Pennsylvania's ("Columbia" or "Company") natural gas class cost of service studies,
26 proposed distribution of revenues by customer class and Residential rate design. The
27 purpose of my direct testimony is to provide comments regarding my analysis of the
28 Company's proposals and to present my findings and recommendations based on the
29 studies I have undertaken in this matter.

1 **Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION ON THESE ISSUES IN**
2 **THE PAST?**

3 A. Yes. In addition to sponsoring testimony on behalf of the OCA in Columbia's
4 last three base rate cases, I have provided testimony before this Commission on issues
5 concerning cost allocations, rate design, cost of capital and revenue requirement in
6 numerous natural gas distribution, electric distribution, and water utility general rate
7 cases.

8
9 **II. CLASS COST OF SERVICE**

10
11 **Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF**
12 **SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.**

13 A. Generally there are two types of cost of service studies used in public utility
14 ratemaking: marginal cost studies and embedded, or fully allocated, cost studies.
15 Consistent with the practices of this Commission, Columbia has utilized a traditional
16 embedded cost of service study for purposes of establishing the overall revenue
17 requirement in this case, as well as for class cost of service purposes.

18 Embedded class cost of service studies are also referred to as fully allocated cost
19 studies because the majority of a public utility's plant investment and expense is incurred
20 to serve all customers in a joint manner. Accordingly, most costs cannot be specifically
21 attributed to a particular customer or group of customers. To the extent that certain costs
22 can be specifically attributed to a particular customer or group of customers, these costs
23 are directly assigned in the CCOSS. The costs jointly incurred to serve all or most
24 customers, therefore, must be allocated across specific customers or customer rate
25 classes.

26 It is generally accepted that to the extent possible, joint costs should be allocated
27 to customer classes based on the concept of cost causation. That is, costs are allocated to
28 customer classes based on analyses that measure the causes of the incurrence of costs to
29 the utility. Although the cost analyst strives to abide by this concept to the greatest
30 extent practical, some categories of costs, such as corporate overhead costs, cannot be
31 attributed to specific exogenous measures or factors, and must be subjectively assigned

1 or allocated to customer rate classes. With regard to those costs in which cost causation
2 can be attributed, there is often disagreement among cost of service experts on what is an
3 appropriate cost causation measure or factor; e.g., peak demand, energy or throughput
4 usage, number of customers, etc.

5
6 **Q. MR. WATKINS, IN YOUR OPINION HOW SHOULD THE RESULTS OF A**
7 **CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?**

8 A. Although there are certain principles used by all cost of service analysts, there are
9 often significant disagreements on the specific factors that drive individual costs. These
10 disagreements can and do arise as a result of the quality of data and level of detail
11 available from financial records. There are also fundamental differences in opinions
12 regarding the cost causation factors that should be considered to properly allocate costs
13 to rate schedules or customer classes. Furthermore, and as mentioned previously, cost
14 causation factors cannot be realistically ascribed to some costs such that subjective
15 decisions are required.

16 In these regards, two different cost studies conducted for the same utility and time
17 period can, and often do, yield different results. As such, regulators should consider
18 CCOSS as a guide, with the results being used as one of many tools to assign class
19 revenue responsibility.

20
21 **Q. HAS THIS COMMISSION PROVIDED GUIDANCE AS TO A PREFERRED**
22 **APPROACH TO BE USED IN NATURAL GAS LOCAL DISTRIBUTION**
23 **COMPANY CLASS COST OF SERVICE STUDY?**

24 A. Yes. Based on my experience in other natural gas distribution company rate cases
25 before this Commission, as well as review of Commission Orders in similar cases in
26 which I did not participate, this Commission has a long history of providing guidance as
27 to appropriate cost allocations for natural gas local distribution companies. First, the
28 notion of allocating a portion of Mains investment based on the number of customers has
29 been consistently rejected by this Commission in that there should not be a classification
30 of Mains as partially demand-related and partially customer-related. Instead, the

Commission has consistently found that Distribution Mains should be classified as 100% demand-related; *i.e.* no portion of Mains allocated based on customers.

Second, with regard to the allocation of demand-related Mains, the Commission has consistently found that the allocation of Mains should consider both peak and average demands. For example, in a 2006 Philadelphia Gas Works case (Docket No. R-00061931), the Commission stated in its Order:

“Reviewing the record, we find that the allocation of distribution Mains investment costs should be done using both annual and peak demands.”¹

Third, the Commission has rejected proposals to separate “large” and small” Mains for cost allocation purposes such that all joint use Mains are allocated to classes on the same basis.²

Q. COLUMBIA WITNESS JOHN SKIRTICH HAS CONDUCTED THREE SEPARATE CCOSS’s. PLEASE BRIEFLY DESCRIBE THESE STUDIES.

A. Mr. Skirtich provides CCOSS results using two different methods in the Company’s Filing Exhibit 111. In Schedule 1 of Exhibit 111, Mr. Skirtich provides the results of a study using the Peak Demand method in which Distribution Mains costs are classified and allocated partially on the basis of number of customers and partially on the basis of Design Day Demand, with no recognition to average (annual) demands.³ I will refer to this study as Columbia’s “Customer/Demand” CCOSS.

As indicated earlier, this methodology has been rejected by this Commission in numerous other natural gas Distribution rate cases. The second CCOSS study sponsored by Mr. Skirtich is provided in Exhibit 111, Schedule 2 and utilizes the Peak and Average (“P&A”) methodology with no customer component of Distribution Mains. This methodology allocates Distribution Mains to classes based partially on annual consumption (average demand) and partially on contributions to Peak Day demand, and is consistent with prior Commission guidance. Mr. Skirtich’s third study (provided in

¹ PA PUC v. Philadelphia Gas Works, Docket No. R-00061931, Order, at Page 80.

² PA PUC v. National Fuel Gas Distribution Corporation, Docket No. R-00942991, (83 PA PUC at 356).

³ Mr. Skirtich’s classification of Mains between customer-related and demand-related is based on a minimum-system analysis.

1 Exhibit 111, Schedule 3) reflects an average of his Customer/Demand and Peak and
2 Average studies.

3
4 **Q. IN YOUR OPINION IS ONE OF THESE TWO METHODOLOGIES**
5 **PREFERRED OVER THE OTHER?**

6 A. Yes. In my opinion, the Peak and Average method is a much preferred approach
7 as it more reasonably assigns cost responsibility to customer classes. This Commission
8 has heard the arguments for and against the Peak and Average method applied to natural
9 gas local gas distribution companies ("LDCs") on many occasions and has expressed its
10 preference for this and other methods that reasonably reflect both average day and peak
11 day demands while rejecting studies that only reflect peak day demands, as well as those
12 that allocate a portion of Mains based on customer counts.

13
14 **Q. MR. WATKINS, BEFORE YOU DISCUSS THE SPECIFICS OF YOUR**
15 **DISAGREEMENTS WITH MR. SKIRTICH'S CUSTOMER/DEMAND**
16 **APPROACH, PLEASE EXPLAIN THE BASIC CONCEPTS OF COST**
17 **ALLOCATION FOR PUBLIC UTILITIES AND NATURAL GAS LDCs.**

18 A. As I mentioned earlier, the majority of a LDCs' plant investment serves
19 customers in a joint manner. In this regard, the LDC's infrastructure is a system
20 benefiting all customers. If all customers were the same size and had identical usage
21 characteristics, cost allocation would be simple (even unnecessary. However, in reality, a
22 utility's customer base is not so simple. Customers (or customer groups) tend to vary
23 greatly in the amount of service required throughout the year such that there are small
24 usage and large usage customers. Therefore, differences in usage should be considered.
25 Because different groups of customers also utilize the system at varying degrees during
26 the year, consideration should also be given to the demands placed on the system during
27 peak usage periods.

28
29 **Q WHY DO COST ANALYSTS SOMETIMES CLASSIFY AND ALLOCATE A**
30 **PORTION OF DISTRIBUTION PLANT ON THE NUMBER OF CUSTOMERS?**

1 A. Largely as a result of differences in customer densities throughout a utility's
2 service area, utility Distribution plant is sometimes classified as partially demand-related
3 and partially customer-related. Possibly the best way to explain why customer densities
4 may be important in the assignment of Distribution costs to individual classes is by way
5 of example. Consider two different utilities: a rural electric utility with urban, suburban,
6 and rural service areas and another utility with only urban and suburban customers. With
7 respect to the electric utility with a rural service area, many miles of conductors and
8 associated plant must be installed in order to serve the demands of relatively few
9 customers. Conversely, many more customers are served on a per mile basis for the
10 urban/suburban utility. With respect to the utility with a rural service area, such an
11 allocation based on usage or demand may be unfair if some classes are located mainly in
12 urban or suburban areas, while other classes of customers are located in urban, suburban,
13 and rural areas. As a result, some cost studies classify Distribution plant as partially
14 demand-related and partially customer-related.

15
16 **Q. IN THE ABOVE EXAMPLE, YOU REFERRED TO ELECTRIC UTILITIES**
17 **INSTEAD OF NATURAL GAS UTILITIES. IS THERE A REASON WHY YOU**
18 **SELECTED THE ELECTRIC UTILITY INDUSTRY FOR YOUR EXAMPLE?**

19 A. Yes. Although the concepts are the same between electric and natural gas
20 Distribution facilities (e.g., conductors are synonymous with Mains), electric utilities are
21 required to serve rural (sparsely populated) areas. Such requirements are not in place for
22 natural gas LDCs. Moreover, electric utilities are required to connect all consumers
23 regardless of density or usage. Such is not the case for natural gas LDCs, as their tariffs
24 allow the utility to only connect those customers in areas with sufficient customer
25 densities and usage.

26 As such, and as a general matter, a Customer/Demand classification of electric
27 Distribution facilities may be appropriate given the characteristics of a utility's service
28 area, but are rarely appropriate for natural gas LDCs with more densely populated service
29 areas that are not required to serve all potential residences and businesses.

1 **Q. HOW APPROPRIATE IS A CUSTOMER/DEMAND SEPARATION FROM A**
2 **DESIGN OR OPERATIONAL PERSPECTIVE?**

3 A. First and foremost, the classification of Distribution plant as partially customer,
4 and partially demand-related results from the view that the assignment of these plant
5 items to classes based solely on a demand allocator would not be equitable to some
6 classes. When classifying individual accounts within Distribution plant, analysts
7 sometimes do not consider how a Distribution system is designed and connected.

8 There are several major factors the analyst should keep in mind when classifying
9 natural gas Distribution plant. First is the fact that purchasing economies are usually
10 present. For example, there are many types and sizes of pipe manufactured. However,
11 due to purchasing economies, a utility may purchase only a few different sizes of pipe.
12 This will result in some “over capacity,” however, the total installed cost will be less than
13 if every segment of the system is optimally sized. Second, most components of the
14 Distribution system are somewhat oversized for other reasons, such as pressure
15 equalization, safety, reliability, and growth uncertainty. Third, historical asset records
16 reflecting capitalized labor and material costs by size and type of investment are far from
17 perfect.⁴ These asset records are the underlying source for conducting minimum size and
18 zero-intercept studies. Fourth, and particularly relevant to most natural gas LDCs, is that
19 it generally costs significantly more to install and maintain Mains pipes in more urban
20 (densely populated) areas of the Company’s service area than in its more suburban (less
21 densely populated) areas. This is because of the infrastructure within, and adjacent to,
22 Mains rights-of-way as well as the predominant types of pipe used in various areas. In
23 the more urban parts of a service area, Mains are generally buried under roads and
24 sidewalks creating significantly higher costs than suburban areas in which a single trench
25 along a road-side is often the only thing necessary. Moreover, due to the size of pipes
26 required as well as safety needs, larger pipes in the suburban areas tend to be steel as
27 opposed to much cheaper plastic pipe.

⁴ Reasons for less than perfect record keeping include: the loss of data over time, the changing needs of recordkeeping by a Company, data processing limitation, different record keeping practices and detail by companies prior to mergers/acquisition by other companies.

1 Although these factors are reflective of how Distribution systems are actually
2 installed and operated, classification studies do not account for these factors. In fact, the
3 presence of these factors can seriously skew the results of such studies.
4

5 **Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH MR. SKIRTICH'S**
6 **CUSTOMER/DEMAND METHOD THAT DOES NOT CONSIDER ANNUAL**
7 **USAGE.**

8 A. Mr. Skirtich's Customer/Demand study is also known as the Peak Responsibility
9 method for assigning the demand portion of Mains. There are several reasons why the
10 Peak Responsibility method is not appropriate for Columbia. The first is the recognition
11 of how and why natural gas consumers are customers of Columbia. That is, customers
12 connect to the Company's system in order to meet their natural gas needs throughout the
13 year. Indeed, the Company's Mains are utilized each and every day of the year and
14 recognition of annual usage (throughput) is a logical basis for cost assignment.

15 Another shortcoming of Mr. Skirtich's Peak Responsibility method using Design
16 Day demands is that the "Design Day" is a moving target over time. That is, Columbia's
17 natural gas Mains were actually planned and installed decades ago to serve the needs and
18 mix of customers that existed at that time. However, Mr. Skirtich's Design Day demand
19 is a function of the current mix, usage per customer, and number of customers today.
20 Columbia's Commercial centers have obviously changed over the last two decades. Yet,
21 Mr. Skirtich's Customer/Demand CCROSS assumes the entire Company system is
22 currently optimally designed and installed to meet today's mix and level of customers. In
23 this regard, and perhaps most important is the fact that there is significant excess capacity
24 within Columbia's Distribution system. This excess capacity is exemplified by the fact
25 that Columbia has not interrupted any customers in the recent past.⁵
26

27 **Q. IS COLUMBIA PROPOSING A SIGNIFICANT CHANGE IN ITS CLASS COST**
28 **ALLOCATION METHODOLOGY IN THIS CASE?**

⁵ Per Columbia response to Standard Data Request No. COS-16 and OCA V-5.

1 A. Yes. In prior cases, Columbia has allocated all common (joint) use Mains on the
2 same basis regardless of size or type.⁶ However, in this case, the Company proposes to
3 separate joint use Mains between “small customer Mains” and “remaining portion of
4 Mains” such that “small customer Mains” investment (and attendant expenses) are
5 allocated only to the Residential (RS/RDS) and Small Commercial (SGS/SGDS) classes
6 while the “remaining portion of Mains” investment (and attendant expenses) are allocated
7 to all customer classes.
8

9 **Q. DO ANY OTHER MAJOR NATURAL GAS LDCs IN PENNSYLVANIA UTILIZE**
10 **SUCH A BIFURCATION OF MAINS FOR COST ALLOCATION PURPOSES?**

11 A. No. I have participated in numerous Pennsylvania gas rate cases over the last
12 decade including Equitable Gas, various UGI divisions, National Fuel Gas, Philadelphia
13 Gas Works, and Valley Energy, and none discriminate between small and large Mains or
14 those common use Mains serving only selected customer classes.
15

16 **Q. HAS A COST ALLOCATION APPROACH TO BIFURCATE COMMON USE**
17 **MAINS PREVIOUSLY BEEN ADDRESSED BY THIS COMMISSION?**

18 A. Yes. In 1994, National Fuel Gas Distribution Corporation (“NFGD”) proposed a
19 cost allocation methodology similar to that proposed by Columbia in this case (Docket
20 No. R-00942991). In that case, the Commission flatly rejected NFGD’s proposal on
21 several grounds. First, the Commission found that the bifurcation of common use Mains
22 between small volume and large volume users reflects little more than previously rejected
23 proposals to classify Mains as partially customer-related and partially demand-related
24 (minimum system or zero-intercept). Second, the Commission noted that NFGD’s
25 proposed approach did not consider or reflect the use or utilization of larger-size
26 distribution Mains by small and large volume customer classes. In addition, the
27 Commission found that “NFGD’s current system embodies numerous past and ongoing
28 augmentations to meet the continually changing requirements of its customers, and it is

⁶ For several rate cases, Columbia has directly assigned Mains specifically utilized by MLD/MDS customers.

1 simply improper to look at the distribution system at a particular point in time and
2 attempt to identify a particular series of Mains to particular customer classes.⁷
3

4 **Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR REVIEW AND**
5 **ANALYSIS OF THE CCOSS SPONSORED BY COLUMBIA WITNESS**
6 **SKIRTICH.**

7 A. For reasons previously discussed, my analysis has focused on the Peak and
8 Average method such that the remainder of my testimony relating to CCOSS concerns
9 the Peak and Average method. With regard to Mr. Skirtich's Peak and Average CCOSS,
10 I first reviewed the model's structure and organization in order to understand the
11 approaches and practices employed. I then reviewed the accuracy and completeness of
12 the primary drivers (allocators) used to assign costs to the customer rate classes identified
13 therein. Next, I verified the accuracy of Mr. Skirtich's CCOSS by examining the
14 calculations embedded within his electronic spreadsheet model. Finally, I adjusted two
15 aspects of the Company's P&A study to correct for one mathematical oversight and to
16 better reflect what I consider a more reasonable assignment of cost responsibility to
17 customer rate classes in accordance with prior Commission guidance.
18

19 **Q. PLEASE SUMMARIZE MR. SKIRTICH'S PEAK AND AVERAGE RESULTS**
20 **AT CURRENT RATES.**

21 A. The following are Mr. Skirtich's class rates of return and indexed rate of return at
22 current rates under his Peak and Average study:
23

Class	Skirtich P&A Results At Current Rates	
	ROR	Indexed ROR
Residential (RS/RDS)	3.93%	96%
Small General Service (SGS/SGDS)	2.86%	69%
Large General Service (LGS)	3.45%	84%
Small Distribution Service (SDS)	12.97%	315%
Large Distribution Service (LDS)	5.28%	128%
Main Line Distribution Service (MDS)	269.19%	654%
Total Company	4.11%	100%

7
83 PA PUC at 359-360.

1 **Q. BEFORE WE CONTINUE, PLEASE EXPLAIN WHY THE MDS CLASS SHOWS**
2 **A NOMINAL RATE OF RETURN OF 269%.**

3 A. This class represents large customers situated adjacent to interstate pipelines such
4 that short spurs of Mains are directly assigned to these customers. As a result, this class
5 is only directly assigned a very small amount of Mains. This direct assignment of Mains
6 filters throughout the CCOSS such that the MDS class is also allocated very few other
7 rate base and expense costs. As a result, small changes in operating income (due to
8 expense allocations) result in very large changes in this class' ROR (due to very little rate
9 base assigned to this class). Due to competitive pressures resulting from potential
10 bypass, this class' rates are value of service-based and, therefore, allocated costs based
11 on direct assignment are rather meaningless.

12
13 **Q. HAVE YOU MADE, AND DO YOU RECOMMEND, ANY ADJUSTMENTS TO**
14 **COLUMBIA'S P&A CCOSS?**

15 A. Yes. I recommend two adjustments to Mr. Skirtich's P&A CCOSS filed in this
16 case: the first adjustment reflects a minor correction of a mathematical oversight
17 embedded within Mr. Skirtich's CCOSS electronic model; while the second adjustment
18 reflects the consistent allocation of common use Mains across all customer classes.

19
20 **Q. PLEASE EXPLAIN YOUR CORRECTION OF THE MATHEMATICAL**
21 **OVERSIGHT EMBEDDED WITHIN MR. SKIRTICH'S ELECTRONIC CCOSS**
22 **MODEL.**

23 A. In response to OSBA I-12, the Company acknowledged that Rate Schedule SCD
24 volumes were inadvertently excluded in the Factor 25 calculation, which is used to
25 allocate storage-related plant and expenses. I have included Rate Schedule SCD (and
26 SGDS) volumes within Factor 25, which slightly increases the costs allocated to the
27 SGS/SGDS class and slightly reduces the costs assigned to all other classes.

28
29 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REFLECT THE CONSISTENT**
30 **ALLOCATION OF COMMON USE MAINS ACROSS ALL CUSTOMER**
31 **CLASSES.**

A. As discussed earlier, Mr. Skirtich bifurcated common use Mains between “small customer Mains” and “remaining portion of Mains” wherein his “small customer Mains” are assigned only to the RS/RDS and SGS/SGDS classes, while the “remaining portion of Mains” were assigned to all customer classes except MDS (RS/RDS, SGS/SGDS, LGS, SDS, and LDS). I have adjusted Mr. Skirtich’s allocation Factor 5 (used to allocate Mains in his bifurcated manner) to treat all common use Mains in the same manner; i.e., allocation of all common Mains to all classes excluding MDS, based on peak and annual (average) demands.

Q. WHAT IS THE EFFECT OF YOUR TWO ADJUSTMENTS TO MR. SKIRTICH’S P&A CCOSS AT CURRENT RATES?

A. As indicated earlier, correction of the mathematical oversight within Mr. Skirtich’s model slightly decreases the rate of return (“ROR”) achieved by the SGS/SGDS class (and slightly raises all other classes’ ROR’s). My adjustment to allocate all common use Mains in the same manner has a much more profound effect on class ROR’s such that the small volume class ROR’s (RS/RDS and SGS/SGDS) increase significantly while the large volume class ROR’s (LGS, SDS and LDS) decrease substantially.

A summary comparison of Mr. Skirtich’s as-filed P&A CCOSS results and those as adjusted are provided below:

P&A CCOSS				
Class ROR’s at Current Rates				
Class	ROR		Indexed ROR	
	Skirtich	OCA Adjusted	Skirtich	OCA Adjusted
RS/RDS	3.93%	4.74%	96%	115%
SGS/SGDS	2.86%	3.69%	69%	90%
LGS	3.45%	0.37%	84%	9%
SDS	12.97%	5.06%	315%	123%
LDS	5.28%	0.55%	128%	13%
MDS	269.19%	284.99%	654%	693%
Total Company	4.11%	4.11%	100%	100%

1 The details of my CCOSS results (utilizing Mr. Skirtich's model as adjusted) are
2 provided in my Schedule GAW-2.

3
4 **III. CLASS REVENUE ALLOCATION**

5
6 **Q. HOW DID COLUMBIA ASSIGN ITS REQUESTED \$77.3 MILLION RATE**
7 **INCREASE TO INDIVIDUAL CLASSES?**

8 A. Company witness Paula Strauss explains that she initially assigned non-gas class
9 revenues based on the results of Mr. Skirtich's CCOSS that utilizes the average of the
10 Customer/Demand and P&A methods. These initial, and purely mathematical, results
11 were then adjusted for a variety of reasons. First, no rate increase is proposed for the
12 MDS class given its high ROR. Next, the LDS class was assigned no increase also due to
13 Mr. Skirtich's calculated high ROR as well as the presence of discounted (flex) rate
14 customers. Finally, even though Mr. Skirtich's average CCOSS study indicates that the
15 Residential class ROR is lower than the system average ROR, Ms. Strauss mitigated the
16 increase to this class in the interest of rate continuity and gradualism. In order to do so,
17 she assigned a minimal increase to the SDS class and a somewhat higher increase than
18 that obtained on a pure CCOSS basis to the SGS/SGDS class.

19
20 **Q. PLEASE PROVIDE A SUMMARY OF COLUMBIA'S PROPOSED CLASS**
21 **REVENUE INCREASE.**

22 A. The table below provides a summary of the revenue increases proposed by Ms.
23 Strauss:

Columbia Proposed Revenue Distribution Without Gas Costs

(\$000)

	(1)	(2)	(3)	(4)	(5)	(6)
	Columbia Proposed					
	Current Base	Base	GPC	GPC Plus	Total	Percent
Class	Rate Revenue	Distribution Revenue	Revenue	Base Dist. Revenue	Increase (4) - (1)	Increase (5)/(1)
Residential: (RS/RDS)	\$163,499.8	\$224,946.8	\$332.2	\$225,279.0	\$61,779.2	37.79%
Small Gen'l Service: (SGS/SGDS)	\$37,168.5	\$51,406.2	\$119.2	\$51,525.4	\$14,356.9	38.63%
Large Gen'l Service: (LGS)	\$1,562.3	\$2,131.0	\$13.0	\$2,144.0	\$581.7	37.23%
Small Delivery Service: (SDS)	\$9,520.3	\$10,102.0	\$0.4	\$10,102.4	\$582.1	6.11%
Large Delivery Service: (LDS)	\$12,850.8	\$12,861.9	\$0.0	\$12,861.9	\$11.1	0.09%
Mainline Service: (MDS)	\$1,249.4	\$1,249.7	\$0.0	\$1,249.7	\$0.3	0.02%
TOTAL	\$225,851.1	\$302,697.6	\$464.8	\$303,162.4	\$77,311.3	34.23%

As shown above, Ms. Strauss proposes virtually no increase to the MDS and LDS classes, a minimal increase to the SDS class, and approximate equal percentage increases to the RS/RDS, SGS/SGDS, and LGS classes.

Q. YOU INDICATED THAT MS. STRAUSS CONSIDERED THE PRESENCE OF FLEX, OR DISCOUNTED, RATE CUSTOMERS IN DEVELOPING HER RECOMMENDED CLASS REVENUE ALLOCATION. PLEASE EXPLAIN THESE DISCOUNTED RATES.

A. Although the Commission approves specific prices for each rate schedule, Columbia will discount its Distribution prices to certain customers that claim to have competitive alternatives. These competitive alternatives can be classified into three categories: competition from alternative forms of energy (oil or propane); competition from other natural gas Distribution utilities (referred to as Distribution "gas-on-gas" competition); or, the threat of bypassing Columbia's Distribution system by purchasing its natural gas requirements directly from interstate pipelines (referred to as "threat of bypass").

Q. IS MS. STRAUSS' CLASS REVENUE INCREASE ALLOCATION REASONABLE?

1 A. In large part, no. The foundation of Ms. Strauss' class revenue allocation is Mr.
2 Skirtich's CCOSS based on the average of the Customer/Demand and P&A methods
3 which, in my opinion, is severely biased against small volume user classes, and directly
4 contradicts prior Commission guidance. As indicated earlier in my testimony, Mr.
5 Skirtich's CCOSSs (including his average of two methods study) over-allocate costs to
6 small volume users in two primary regards. First, his study inappropriately classifies and
7 allocates a significant portion of Mains based on customers as a result of his minimum-
8 system study. Second, he over-assigns costs to small volume customers by bifurcating
9 common use Mains. Both of these approaches have specifically been rejected by the
10 Commission.

11 In addition, Ms. Strauss effectively spreads the revenue shortfall resulting from
12 discounted rates available only to certain Commercial and Industrial customers to those
13 classes and customers that are captive to Columbia's distribution system and therefore,
14 do not directly benefit from the discount program. This Commission has stated that
15 revenue shortfalls due to discounts must remain within the same customer class. An
16 example of this practice relates to the various Customer Assistance Programs ("CAP")
17 and Universal Service Programs ("USP") offered to the Residential class by virtually all
18 natural gas LDCs in Pennsylvania. That is, whereas discounts are typically available to
19 certain low-income Residential consumers, this Commission has ruled on several
20 occasions that the revenue shortfall (and costs) associated with CAP and USP must
21 remain within, and be the sole responsibility of, the Residential class such that the
22 Commercial and Industrial classes bear no responsibility for these discounts. The
23 Commission's rationale on these cases has been that the Residential class is the only
24 group of customers who benefit for CAP/USP rates and hence, the impact of these
25 discounts should be totally borne by other Residential customers.

26
27 **Q. ARE FLEX RATES AVAILABLE TO RESIDENTIAL CUSTOMERS?**

28 A. No.
29

30 **Q. HAVE YOU DEVELOPED A MORE APPROPRIATE, AND COST-BASED**
31 **CLASS REVENUE INCREASE ALLOCATION?**

1 A. Yes.

2
3 **Q. PLEASE EXPLAIN YOUR PROPOSED CLASS REVENUE ALLOCATION**
4 **BASED ON THE COMPANY'S OVERALL REQUESTED \$77.3 MILLION**
5 **INCREASE.**

6 A. On a general level, I developed my proposed class revenue allocations based
7 upon: reliance on CCOSS results which were conducted using Commission approved
8 methods; maintaining the impact of rate discounts within the classes that enjoy such
9 discounts to the largest extent possible; consideration of rate gradualism by
10 recommending that no class receive an increase greater than 150% of the system-wide
11 percentage increase in base (non-gas) rates; and, no class receiving a revenue decrease.

12 As discussed earlier, when the Company's adjusted P&A CCOSS is considered,
13 the Residential class ROR (4.74%) is somewhat above the system average ROR of 4.11%
14 (but lower than a required ROR), the SGS/SGDS ROR (3.69%) is marginally below the
15 system average, the LGS and LDS classes are significantly revenue deficient with ROR's
16 of 0.37% and 0.55%, respectively, the SDS class ROR (5.06%) is somewhat above the
17 system average, and the MDS class is achieving a very high, fully allocated ROR. As a
18 result, it is reasonable and appropriate to assign no revenue increase to the MDS class, a
19 somewhat lower than system average percentage increase to the SDS class, about the
20 system average percentage increase to the Residential and SGS/SGDS classes, and
21 considerably higher than system average percentage increases to the LGS and LDS
22 classes.

23 With regard to the presence of discounted rates, I then examined the relative
24 levels and reasons for such discounts across classes. In response to Data Request I&E-
25 RS-7-D, the Company provided the amount of individual customer discounted revenues
26 (i.e., differentiated between actual revenue and revenue at full tariff rates) as well as the
27 reasons for offering such discounted rates.⁸ The table below provides a summary of such
28 discounts by class and by reason for discount:
29

⁸ This interrogatory response is marked as confidential because it contains individual customer information; however, Columbia does not oppose treating the aggregate information, as it is presented in the table on page 17, as non-confidential.

Company Flex Rate Discounts						
	(1)	(2)	(3)	(4)	(5)	(6)
	Discounted Revenue					
Class	Current Base Rate Revenue	By Pass	Gas on Gas	Alternative Energy	Total	Percent Of Curr. Revenue
Residential: (RS/RDS)	\$163,499.8	\$0.0	\$0.0	\$0.0	\$0.0	0.00%
Small Gen'l Service: (SGS/SGDS)	\$37,168.5	\$0.0	\$11.0	\$0.0	\$11.0	0.03%
Large Gen'l Service: (LGS)	\$1,562.3	\$0.0	\$0.0	\$0.0	\$0.0	0.00%
Small Delivery Service: (SDS)	\$9,520.3	\$8.5	\$68.2	\$0.0	\$76.7	0.81%
Large Delivery Service: (LDS)	\$12,850.8	\$1,693.6	\$1,344.6	\$34.7	\$3,072.9	23.91%
Mainline Service: (MDS)	\$1,249.4	\$319.4	\$0.0	\$0.0	\$319.4	25.56%
TOTAL	\$225,851.1	\$2,021.5	\$1,423.8	\$34.7	\$3,480.0	1.54%

As indicated above, virtually all of the discounts are associated with the LDS and MDS classes. Since I am proposing no increase to the MDS class, no further consideration of discounted rates associated with these customers was necessary. With regard to the LDS class, slightly less than the one quarter of current distribution revenues are discounted (\$3.1 million out of \$12.9 million). Of the \$3.1 million of LDS rate discounts, about half (\$1.7 million) is attributable to threat of transmission company bypass and about half (\$1.4 million) is attributable to either gas on gas or alternative fuel competition.

Although Residential and Small Commercial customers have no ability to enjoy rate discounts due to a threat of transmission company bypass, I believe it is fair for all classes to share in the responsibility associated with such discounts. With regard to distribution company gas on gas competition, revenue responsibility for discounts should remain in their respective classes. As such, even though the LDS class ROR is significantly deficient (0.55%), increasing LDS full tariff revenues by 150% of the system average percentage increase may not be fair to these customers. Therefore, I reduced the LDS increase from 150% to 135% of the system average percentage increase. In addition, given the relatively high ROR achieved by the SDS class, I recommend this class' revenues be increased at 75% of the system average percentage increase. The following table provides my recommended class revenue increases at the Company's requested overall increase:

OCA Proposed Revenue Distribution Excluding Gas Costs
(\$000)

	(1)	(2)	(3)	(4)	(5)	(6)
	OCA Proposed					
		Pct of			Base	Pct. Increase
	Current Base	Sys. Avg	Total	GPC	Distribution	Base Dist.
Class	Rate Revenue	Increase	Increase	Revenue	Revenue	Revenue
					(3) - (4)	(5)/[(1) - (4)]
Residential: (RS/RDS)	\$163,499.8	Residual	\$55,507.7	\$332.2	\$55,175.5	33.82%
Small Gen'l Service: (SGS/SGDS)	\$37,168.5	Residual	\$12,618.6	\$119.2	\$12,499.4	33.74%
Large Gen'l Service: (LGS)	\$1,562.3	150%	\$802.2	\$13.0	\$789.2	50.94%
Small Delivery Service: (SDS)	\$9,520.3	75%	\$2,444.2	\$0.4	\$2,443.8	25.67%
Large Delivery Service: (LDS)	\$12,850.8	135%	\$5,938.6	\$0.0	\$5,938.6	46.21%
Mainline Service: (MDS)	\$1,249.4	0%	\$0.0	\$0.0	\$0.0	0.00%
TOTAL	\$225,851.1		\$77,311.3	\$464.8	\$76,846.5	34.10%

Q. IN THE EVENT THE COMMISSION AUTHORIZES LESS THAN THE \$77.3 MILLION INCREASE REQUESTED BY COLUMBIA, HOW SHOULD YOUR PROPOSED REVENUE ALLOCATION BE SCALED-BACK?

A. Any reduction to Columbia's requested overall revenue requirement should be scaled-back in proportion to my recommended class revenue allocation discussed earlier.

IV. RESIDENTIAL RATE DESIGN

Q. PLEASE DESCRIBE COLUMBIA'S CURRENT RESIDENTIAL RATE STRUCTURE.

A. Columbia's current Residential rate structure is known as a minimum usage rate in that base rates include a fixed monthly customer charge of \$18.73 plus a flat Distribution usage charge of \$2.6708 per Dth for all gas consumed in excess of 2.1 Dth per month.

1 **Q. WHAT RATE STRUCTURE DOES COLUMBIA PROPOSE FOR THE**
2 **RESIDENTIAL CUSTOMER CLASS IN THIS CASE?**

3 A. Columbia is proposing three rate design options for non-USP Residential
4 customers. Columbia's first, and recommended Residential rate design is comprised of a
5 fixed monthly customer charge of \$19.00 plus a flat usage charge of \$3.8621 per Dth for
6 all consumption, plus a guaranteed revenue collection mechanism (referred to by
7 Columbia as a revenue normalization adjustment). Columbia's proposed Residential
8 Option 2 is similar in basic structure to its preferred Option 1 except that guaranteed
9 revenue recovery is limited to weather variations. In order to reflect the fact that 100% of
10 Residential revenues are not guaranteed through a usage based adjustment factor, Ms.
11 Strauss proposes a significantly higher customer charge of \$29.00 per month under her
12 Option 2 (weather normalization) scenario. Columbia's Option 3 reflects a fixed charge
13 of \$45.49 per month for all Residential customers regardless of usage.
14

15 **Q. MR. WATKINS, HAVE YOU IDENTIFIED A COMMON OBJECTIVE IN**
16 **COLUMBIA'S RESIDENTIAL RATE DESIGN PROPOSALS?**

17 A. Yes. It is clear that the primary objective of Columbia's Residential rate design is
18 to negate virtually all risks associated with serving its Residential customers by
19 guaranteeing its revenues from these customers.
20

21 **Q. DOES COLUMBIA PROPOSE GUARANTEED REVENUE RECOVERY RATE**
22 **MECHANISMS FOR ITS SMALL COMMERCIAL, LARGE COMMERCIAL OR**
23 **INDUSTRIAL CUSTOMERS?**

24 A. No.
25

26 **Q. WHY DOES COLUMBIA'S PROPOSED RESIDENTIAL GUARANTEED**
27 **RECOVERY RATE DESIGN OPTIONS REDUCE ITS RISKS?**

28 A. If any business, governmental, or non-profit enterprises' revenues are guaranteed,
29 that entity's net income and cash flows are more certain. Since risk is nothing more than
30 a measure of certainty, guaranteed revenue collection substantially reduces risk by
31 increasing income and cash flow certainty.

1 **Q. BEFORE YOU CONTINUE, ARE THERE OTHER REGULATORY**
2 **MECHANISMS IN PLACE THAT ALSO INCREASE COLUMBIA'S NET**
3 **INCOME AND CASH FLOW CERTAINTY, THEREBY REDUCING THE**
4 **COMPANY'S RISK?**

5 A. Yes. Any business' net income and cash flow are simply a function of three
6 factors: revenues, expenses and capital expenditures. Columbia's proposed Residential
7 rate design options address its desire to ensure stable revenue recovery. However, for
8 many years this Commission has established natural gas LDC revenue requirements
9 based on "normal weather." This ratemaking approach reduces LDC's risks in that while
10 a given year's revenue may be higher or lower due to colder or warmer winter weather,
11 the prices consumers pay are "normalized" such that in one year an LDC may recover
12 less revenue than anticipated followed by higher than expected revenue in a following
13 year. As such, assuming that short-term fluctuations in winter weather are relatively
14 random in nature, the LDC's risk is reduced over time. With regard to the latter two
15 factors (expenses and cash flow), Columbia is guaranteed recovery of its largest expense:
16 gas costs, through a reconcilable gas cost recovery mechanism. Finally, as a result of
17 recent state legislation, Columbia's risk has been further reduced due to certain
18 ratemaking procedures that have been codified. Specifically, Columbia is now entitled to
19 use a fully forecasted rate year for revenue requirements that serve as a basis for
20 establishing prices (rates) based on anticipated usage and expenses up to 18 months into
21 the future (i.e., rate year ending June 2014). In addition, recent legislation authorizes the
22 Commission to approve LDC Distribution System Improvement Charges ("DSIC") in
23 which prices are automatically increased outside the context of rate cases based on the
24 level of new investments by LDC's.⁹

25 With the above mechanisms in place, Columbia's net income and cash flows are
26 largely ensured, but for Force Majeure, the effects of year to year revenue variation, and
27 expense variations within management's control.

28
29 **Q. IS THERE A RELATIONSHIP BETWEEN RISK AND REQUIRED RATE OF**
30 **RETURN?**

⁹ Columbia filed a petition for approval of a DSIC on January 2, 2013 (Docket No. P-2012-2338282).

1 A. Absolutely. As is well known in financial and regulatory arenas, a firm's required
2 rate of return is directly-related to the risk it confronts.
3

4 **Q. HOW DOES THIS RISK AND REQUIRED RATE OF RETURN RELATE TO**
5 **COLUMBIA'S PROPOSED RESIDENTIAL RATE DESIGN OPTIONS?**

6 A. Although Columbia's overall risk is reduced due to its use of a future rate year
7 and availability of a DSIC, this risk and required return for Residential customers would
8 be virtually eliminated if any of the Company's rate design options were approved.
9 Stated otherwise, if the Commission were to approve any of Ms. Strauss' proposed
10 Residential rate design options, the required rate of return for the Residential class would
11 be lower than that of Columbia Gas of Pennsylvania as a whole. Therefore, the required
12 revenue increase to the Residential class would be substantially less than the percentage
13 Residential increase I recommend. Indeed, should the Commission adopt any of the
14 Residential guaranteed revenue recovery rate design options offered by Columbia,
15 different class rates of return are clearly appropriate such that the required Residential
16 rate of return would be much lower than all other classes.
17

18 **Q. HAVE YOU QUANTIFIED THE REDUCTION TO THE RESIDENTIAL**
19 **REQUIRED RATE OF RETURN OR REQUIRED REVENUE INCREASE IF**
20 **THE COMMISSION WERE TO ADOPT ANY OF THE COMPANY'S**
21 **PROPOSED RESIDENTIAL RATE DESIGN OPTIONS?**

22 A. Not at this time. This is because I recommend that none of Columbia's
23 Residential rate design options be approved because they are not in the public interest,
24 unreasonably tilt the balance of ratepayer and shareholder interests in favor of the
25 Company, do not comport with sound economic pricing theory and policies, and do not
26 promote conservation of natural gas.
27

28 **Q. WHY ARE COLUMBIA'S RESIDENTIAL RATE DESIGN OPTIONS NOT IN**
29 **THE PUBLIC INTEREST?**

30 A. Notwithstanding the risk/return and conservation shortcomings of Columbia's
31 Residential rate design options, these proposals are at odds with the most basic tenets of

1 basic economic theory and the core of our economic system. That is, in our society,
2 business enterprises are created and exist to serve a public need for services and products
3 demanded by consumers. Under our approach to society's scarce resources, businesses
4 fairly compete with no guarantees of recovering their investments (or expenses). In turn,
5 businesses with varying levels of uncertainty (risk) require varying levels of profitability.
6 With regard to public utilities, it is generally agreed upon that because of their monopoly
7 status, regulation is necessary and that such regulated rates should serve as a surrogate (or
8 mirror) for competition to the greatest extent practical. As a result, and in my opinion,
9 the guarantee of revenue recovery severely contradicts basic economic philosophy.
10

11 **Q. WHY ARE COLUMBIA'S PROPOSED RESIDENTIAL RATE DESIGN**
12 **OPTIONS AT ODDS WITH CONSERVATION?**

13 A. Efficient pricing (which is volumetric based) results in the most efficient
14 utilization of scarce resources. That is, as a consumer demands more (or less) of a scarce
15 resource, the overall cost to the consumer increases (or decreases). To the extent that the
16 total amount paid for a scarce resource does not vary, or does not realistically reflect the
17 amount consumed, the price signal received by the consumer does not maximize the
18 efficient conservation of the scarce resource.
19

20 **Q. BEFORE WE CONTINUE, IS COLUMBIA PROTECTED FROM RESIDENTIAL**
21 **REVENUE EROSION DUE TO THE MORE EFFICIENT UTILIZATION OF**
22 **NATURAL GAS APPLIANCES ON A GOING-FORWARD BASIS?**

23 A. Yes. The Company's revenue requirement (and resulting Residential rates), will
24 be based on a fully forecasted rate year that ends almost eighteen months into the future.
25 The Company's sales and revenue forecast utilized to develop its revenue requirement
26 and Residential billing determinants (Dth throughput) explicitly incorporates an
27 appliance efficiency variable such that the Company's forecasts reflect a further
28 reduction in natural gas utilization per Residential customer.
29

1 **Q. HAS COLUMBIA AND THE REST OF THE LDC INDUSTRY BEEN ABLE TO**
2 **REMAIN FINANCIALLY VIABLE OVER THE YEARS WITHOUT**
3 **GUARANTEED REVENUE RECOVERY?**

4 A. Yes. For decades, the pricing structure of natural gas LDCs has been largely
5 volume based and not subject to revenue guarantees. The natural gas LDC industry has
6 remained viable and has achieved, at the very least, respectable returns on their
7 investments with this volumetric based rate structure. For example, faced with largely
8 volumetric rate structures and no guaranteed revenue recovery in general, the Value Line
9 group of natural gas utility companies has achieved the following average rates of return
10 on common equity each year since 2000:

Value Line Natural Gas Utility Rate of Return on Common Equity <u>a/</u>	
Year	
2000	11.7%
2001	12.2%
2002	11.8%
2003	12.1%
2004	11.1%
2005	12.0%
2006	12.2%
2007	11.4%
2008	11.8%
2009	12.1%
2010	11.6%
2011	10.4%
Average	11.7%

a/ Calculated per Schedule GAW-3.

26 While it is true that natural gas LDC's have been faced with declining usages per
27 customer due to improvements in appliance efficiency, earnings (with revenue generated
28 largely from volumetric based prices) have been achieved at high levels. These high
29 earnings are largely a result of traditional rate increases, cost savings from technological
30 advances, economies of scales due to mergers, and customer growth.

1 **Q. IN ADDITION TO YOUR GENERAL CONCERNS REGARDING COLUMBIA'S**
2 **PROPOSED RESIDENTIAL RATE DESIGN OPTIONS, DO YOU HAVE**
3 **SPECIFIC CRITICISMS REGARDING THE COMPANY'S OPTION 1, WHICH**
4 **REFLECTS A REVENUE NORMALIZATION ADJUSTMENT MECHANISM?**

5 A. Yes. With regard to Columbia preferred Residential rate design (Option 1) in
6 which there would be a revenue adjustment mechanism, there are several shortcomings in
7 the Company's proposal. First, the proposed revenue normalization mechanism would
8 penalize those customers that actively and aggressively conserve their natural gas usage.
9 This is because the prices paid through the revenue normalization riders are tied to the
10 Company's overall revenue collection for the Residential class. To the extent a
11 Residential customer reduces consumption through conservation, they will still be subject
12 to higher bills due to the actions of others in their class or abnormalities in weather.

13 Second, and perhaps most important, is that prices paid by Residential customers
14 may be more volatile under a revenue normalization adjustment ("RNA") mechanism and
15 contrary to efficient price signals than under a traditional pricing structure. This is
16 because of the timing lag embedded in the proposed RNA. For example, assume that
17 Winter 1 is very mild which results in an "under collection" of Residential revenues.
18 This under collection in Winter 1 would result in a positive RNA (surcharge) that would
19 be imposed and collected during Winter 2. If Winter 2 is colder than normal, customers
20 will require more gas and incur higher bills than would normally be the case. However,
21 due to the RNA surcharge which results from the prior year, customer bills would be
22 even higher. Obviously, the opposite is true as well. In my opinion, such a pricing
23 mechanism totally abandons the economic and public policy goals of efficient pricing.

24 Third, the Company's RNA proposal effectively establishes "seasonal" revenue
25 requirements which are directly used to establish prices outside the context of rate cases.
26 In this regard, the use of a seasonal revenue requirement is at odds with traditional and
27 accepted ratemaking in which a utility's overall (annual) revenue requirement is used as a
28 tool to establish fair and reasonable rates. Furthermore, because the proposed RNA
29 would be changed or adjusted outside the context of a general rate case, in which all
30 aspects of a company's cost of service are evaluated, such adjustment would not receive
31 nearly the same level of review and scrutiny as is the case during a base rate case. For

1 example, if customer growth patterns change and/or utilization does not decline as
2 forecasted by the Company, future RNA's are likely to be overstated. Finally, the
3 proposed RNA contains no true-up mechanism to ensure that the retroactive RNA
4 surcharge or credit actually collects the level of revenue intended.

5
6 **Q. PLEASE DISCUSS YOUR SPECIFIC CRITICISMS REGARDING**
7 **COLUMBIA'S RESIDENTIAL RATE DESIGN OPTION 2, WHICH**
8 **INCORPORATES A WEATHER NORMALIZATION ADJUSTMENT**
9 **MECHANISM.**

10 A. With regard to the Company's weather normalization adjustment ("WNA") rate
11 design Option 2, the additional concerns I have with this option include the following.
12 The proposed WNA is not "dead banded." That is, even if a particular heating season
13 month is only a few heating degrees higher (lower) than what has been defined as
14 "normal," a credit (surcharge) would still apply for a given month. Because the proposed
15 WNA would be calculated on a monthly basis, if a given month's weather varied ever so
16 slightly from the calculated long-term average (normal) a rate adjustment (credit or
17 surcharge) would still be calculated and imposed. Under such circumstances, I do not
18 believe it could reasonably be said that the month's weather was abnormal. In addition,
19 and similar to the RNA option, there will be no detailed review or scrutiny of WNA
20 surcharges and credits as those will be calculated and implemented outside of a rate case
21 with no true-up mechanism.

22
23 **Q. WHAT ARE YOUR CONCERNS AND CRITICISMS OF COLUMBIA'S OPTION**
24 **3 RESIDENTIAL RATE DESIGN WHICH IS SIMPLY A FIXED MONTHLY**
25 **CHARGE PER CUSTOMER REGARDLESS OF CONSUMPTION.**

26 A. This type of fixed fee rate structure was proposed by Columbia in its last rate case
27 (Docket No. R-2010-2215623) and was rigorously opposed by OCA. In that case, I
28 provided considerable testimony on the economic theory of pricing which showed that a
29 "straight-fixed variable" rate design is not in the public interest. Attached to this
30 testimony as Appendix A is the relevant section of my testimony in Columbia's last rate

1 case (Docket No. R-2010-2215623) that addressed Columbia's proposed Residential
2 straight-fixed variable rate design.
3

4 **Q. DO YOU SUPPORT THE CURRENT RESIDENTIAL MINIMUM USE RATE**
5 **STRUCTURE IN WHICH THE FIRST 2.1 DTH OF MONTHLY CONSUMPTION**
6 **IS INCLUDED WITHIN THE FIXED MONTHLY CUSTOMER CHARGE?**

7 A. While the current Residential minimum use rate structure is far superior to any of
8 the three options proposed by Columbia in this case, this rate structure is not a preferred
9 rate design. Minimum use rate designs were fairly common in the 1960's and 1970's.
10 However, this type of rate structure has all but disappeared from investor-owned utilities
11 since about the 1980's. The reasons for the demise of this type of rate structure are two-
12 fold. First, it does not appropriately address conservation efforts in that the price signal
13 establishes a given level of minimum usage for "free," or at no charge. Secondly, small
14 consumers using less than the minimum usage allowance are effectively charged for a
15 utility service (natural gas, electricity or water) that is not used. Indeed, and while there
16 may be a few instances in which a minimum use rate structure still exists for regulated
17 utilities, I am not aware of any gas or electric utility (other than Columbia) that uses this
18 rate structure.
19

20 **Q. HAVE YOU CONDUCTED ANY ANALYSES OF THE DEGREE IN WHICH**
21 **RESIDENTIAL CUSTOMERS USE LESS THAN 2.1 DTH PER MONTH AND**
22 **ARE, THEREFORE, EFFECTIVELY CHARGED FOR GAS SERVICE THAT**
23 **THEY DID NOT UTILIZE?**

24 A. Yes. In response to OCA V-22, the Company provided a detailed database of
25 every Columbia Residential bill during the 24-month period June 2010 to May 2012.
26 This database, which includes more than 300,000 customers with monthly bills over 24
27 months, reflected more than 7 million bills. For purposes of this analysis, I evaluated all
28 Residential bills during the most recent 12-month period contained within the database
29 (3.587 million bills).¹⁰ The following table shows the number and percentage of

¹⁰ Bills with less than 15 days or more than 45 days within a given billing cycle were excluded. Furthermore, the database includes only those physical locations with continuous service throughout the 24-month period.

customers using less than the minimum usage level of 2.1 Dth per month on a monthly basis:

	Number of Bills		% of Bills
	Total	< 2.1 Dth	< 2.1 Dth
June 2011	298,946	174,119	58.2%
July 2011	298,946	223,160	74.6%
Aug. 2011	298,946	240,699	80.5%
Sept. 2011	298,946	235,411	78.7%
Oct. 2011	298,946	127,014	42.5%
Nov. 2011	298,946	27,741	9.3%
Dec. 2011	298,946	13,514	4.5%
Jan. 2012	298,946	7,385	2.5%
Feb. 2012	298,946	7,599	2.5%
Mar. 2012	298,946	9,391	3.1%
Apr. 2012	298,946	23,812	8.0%
May 2012	298,946	49,773	16.6%
Total	3,587,352	1,139,618	31.8%

Although the above table encompasses only the most recent 12-month period, the percentages using less than 2.1 Dth were similar to the prior 12-month period. As can be seen above, about three-quarters (75% to 80%) of all Residential customers actually used less than the minimum threshold during the summer months of July, August and September. In addition, about half of all Residential customers were effectively billed for usage they did not use during the two heating season transition months of June and October. Finally the vast majority of all Residential customers (about 97% to 98%) do exceed the minimum usage threshold during the three coldest winter months of January, February and March.

Q. DO YOU HAVE ANY CONCLUDING COMMENTS REGARDING THE CURRENT MINIMUM USE RATE STRUCTURE?

A. Yes. Given the very large number of Residential bills that do not meet the minimum usage threshold on a monthly or annual basis, I do not believe it is proper ratemaking policy to include a usage allowance within a customers' fixed, or minimum monthly charge.

1 **Q. WHAT IS YOUR OPINION REGARDING THE APPROPRIATENESS OF A**
2 **RESIDENTIAL RATE STRUCTURE WHICH IS COMPRISED OF A MODEST**
3 **FIXED MONTHLY CUSTOMER CHARGE AND A USAGE CHARGED BASED**
4 **ON ALL CONSUMPTION?**

5 A. Modern economic price theory has been extensively studied and used for more
6 than 200 years. Moreover, regulators have considered alternative pricing structures for
7 well over 100 years. The Residential rate structure which consists of a fixed monthly
8 customer charge and usage charge for all consumption is tried and true, consistent with
9 economic theory, has survived the test of time, and provides a reasonable balancing of
10 utility shareholder and captive ratepayer interests. Nothing has significantly changed in
11 the way that natural gas LDC's operate, incur costs, or invest in infrastructure for
12 decades. As a result, in my opinion the best Residential rate structure recovers most of
13 the utility's costs through volumetric rates and limits fixed charges to direct customer
14 costs.

15
16 **Q. DO YOU HAVE ANY CONCLUDING COMMENTS REGARDING THE**
17 **APPROPRIATE RESIDENTIAL RATE STRUCTURE FOR THIS CASE?**

18 A. Yes. As is clear from the testimony of Columbia policy witness Mark Kempic,
19 the Company desires to significantly reduce its risks by shifting revenue collection
20 uncertainty from shareholders to ratepayers. Because Columbia's Residential customers
21 are captive to the utility, they have no choice other than Columbia. I recognize and agree
22 that the Commission must balance the interests of shareholders and ratepayers in all
23 regards. However, in my opinion, the scales of equity and fairness are severely tilted
24 away from Residential customers and towards shareholders under the Company's rate
25 design proposals.

26 As to the need or desire for revenue, net income and positive cash flow stability, I
27 urge the Commission to consider all aspects of fairness including: guaranteed recovery
28 of Columbia's largest expense (gas costs); the Company's utilization of a fully forecasted
29 rate year; and, the opportunity for automatic rate recovery of distribution system capital
30 expenditures outside the context of rate cases. Finally, should the Commission agree
31 with one of Columbia's three Residential rate design options, the authorized ROR to

1 Columbia should reflect the reduced level of risks the Company will confront and that
2 Residential rates specifically should reflect this reduced risk and attendant required ROR.
3

4 **Q. WHAT IS YOUR RECOMMENDATION AS TO THE RESIDENTIAL RATE**
5 **STRUCTURE?**

6 A. I recommend a Residential rate structure consisting of a monthly customer charge
7 along with a single block usage charge.
8

9 **Q. WHAT IS YOUR RECOMMENDATION FOR THE FIXED MONTHLY**
10 **RESIDENTIAL CUSTOMER CHARGE?**

11 A. I recommend a customer charge of \$14.00 per month.
12

13 **Q. WHAT IS THE BASIS FOR RECOMMENDING A CUSTOMER CHARGE OF**
14 **\$14.00?**

15 A. As I discussed earlier, there is no doubt that the majority of Columbia's non-gas
16 costs are fixed in the short-run. However, economic price theory is clear that the
17 incidence or relative level of a firm's fixed costs have no bearing on the establishment of
18 pricing or price structure. Indeed, efficient pricing dictates volumetric pricing. Thus, for
19 public utilities, only a minimum level of fixed customer charges has been recognized to
20 reflect the direct costs of hooking up and maintaining a customer's account. These direct
21 customer costs include the Company's investment in services and meters as well as the
22 operating expenses associated with meter reading, customer service, accounting and
23 customer records and collections. I have conducted a traditional direct customer cost
24 analysis for Columbia which is presented in my Schedule GAW-4. This study indicates a
25 monthly customer cost of \$13.71 per month utilizing the OCA's recommended cost of
26 capital of 7.49% and \$14.83 per month utilizing Columbia's proposed cost of capital of
27 8.52%. Furthermore, even though the risk associated with fixed customer charges is
28 extremely low since it is guaranteed revenue, a lower cost of capital relating to fixed
29 monthly customer charges is warranted in determining customer costs. However, for
30 purposes of my analysis, I have utilized Columbia's overall cost of capital as
31 recommended by OCA witness Kahal.

1 **Q. COLUMBIA PROPOSES TO CHANGE THE TERM “CUSTOMER CHARGE”**
2 **TO “SYSTEM CHARGE.” DO YOU AGREE WITH THIS CHANGE?**

3 A. No. First, I am not aware of any Pennsylvania utility that uses a term other than
4 customer charge as it relates to fixed Residential monthly charges. Second, Commission
5 regulations refer to such charges as “customer charges.”¹¹ Third, the term “customer
6 charge” appears in Commission customer education materials relating to gas shopping.
7 Finally, the changing of this term from “customer charge” to “system charge” would
8 likely cause confusion for customers about the new charge on their bill, as well as
9 causing confusion because their other utility bills uniformly use the term “customer
10 charge.”
11

12 **V. LINE EXTENSIONS AND NEW AREA SERVICE PILOT RIDER**
13

14 **Q. HAVE YOU REVIEWED THE COMPANY’S PROPOSED NEW AREA**
15 **SERVICE (“NAS”) PILOT RIDER?**

16 A. Yes.
17

18 **Q. PLEASE GENERALLY EXPLAIN THE PURPOSE OF THIS NEW RIDER.**

19 A. Columbia is proposing a pilot NAS rider that will be optional (voluntary) to
20 Residential customers to finance the deposit requirements for Main and Company-owned
21 service extensions that would otherwise be required to be paid upfront in a lump sum. In
22 other words, the proposed NAS rider will provide an option to new Residential customers
23 to either pay deposit requirements as set forth in Tariff Rule 8 either on a lump sum basis
24 upfront or financed by Columbia over a period of twenty years.
25

26 **Q. DO YOU HAVE ANY COMMENTS REGARDING THE COMPANY’S PILOT**
27 **RIDER NAS AS IT IS STRUCTURED AND PROPOSED BY COLUMBIA?**

28 A. Yes. While I applaud Columbia for proposing an alternative and voluntary
29 method to assist consumers with the upfront costs of connecting to Columbia’s system, I
30 have several concerns regarding the specifics of this rider as it is proposed. As a result,

¹¹ E.g., 52 Pa. Code §62.80.

1 and while I do not recommend the rejection of the concept of financing customer's
2 deposits due to Mains and service extensions, I do recommend that a decision on this
3 proposed rider be deferred and that a collaborative taskforce or study group which
4 includes all stakeholder interests be established to fully explore all reasonable approaches
5 and conditions for financing customer deposits resulting from Mains and service
6 extensions. In this regard, I believe it is fair to say that both Columbia's and consumer
7 interests are aligned as it relates to a desire to make natural gas more available to
8 Pennsylvanian's.

9
10 **Q. PLEASE OUTLINE YOUR CONCERNS WITH A PILOT NAS RIDER AS**
11 **PROPOSED BY COLUMBIA.**

12 A. This tariff provision effectively provides the Company with the ability to make an
13 unsecured loan to its customers for a specific purpose. Under the Company's proposed
14 tariff provisions, such a loan would be limited to a maximum monthly payment of \$25.00
15 financed over twenty years. While I recognize and appreciate the Company's desire to
16 establish a maximum loan payment amount that is relatively small (\$25.00 per month),
17 the reality is, given the twenty year payback period coupled with an interest rate equal to
18 the authorized cost of capital, the total amount financed will be limited to less than
19 \$3,000. In this regard, financing such a small amount over a twenty-year period may be
20 too long for most customers. Instead, I would recommend a higher monthly payment cap
21 as well as a shorter term for the loan.

22 The next concern I have relates to the Company's proposal to disconnect and
23 terminate a customer's natural gas service in the event of default or late payment of the
24 loan. Although I appreciate Columbia's concerns regarding the guarantee of payment
25 and any resulting impacts on all other ratepayers in the event of a default, I believe it is
26 improper to tie these two services for loan security purposes. In other words, I do not
27 believe it is appropriate for Columbia to be able to disconnect a customer who is
28 otherwise current on their natural gas service payment due to any default or late payment
29 associated with an unsecured loan.

30 The next issue concerns the carry-over of delinquent balances from one customer
31 to the next at the same physical location. While such a proposal may or may not be

1 reasonable when property ownership is transferred, rental property customers (who pay
2 for utility service as part of their lease) should not be held responsible for the actions of
3 prior tenants. Furthermore, it appears from the provisions of the proposed tariff that if
4 the payback from one customer is deficient, or otherwise less than expected, the
5 deficiency will then be spread to all other customers on the Main line extension. Again,
6 it is unreasonable to hold one customer (or a group of customers) financially responsible
7 for the actions or inactions of another customer.
8

9 **Q. PLEASE PROVIDE AN EXAMPLE OF THE INEQUITIES THAT WOULD**
10 **RESULT BY HOLDING ONE CUSTOMER RESPONSIBLE FOR THE ACTIONS**
11 **OF ANOTHER CUSTOMER.**

12 A. To further explain the inequities of this proposed provision of the tariff, suppose
13 there is a Main line extension used to connect ten new customers. Assume that four of
14 the new customers elect to satisfy their deposit requirement with an upfront lump sum
15 payment while the remaining six new customers elect to finance their respective deposit.
16 If after a few years, one of the properties remains vacant, or is behind in its loan payment
17 to Columbia, the arrearage would presumably be paid for only by the remaining five loan
18 participants such that before customers that made their deposit upfront could not (and
19 should not) be responsible for any deposit shortfalls of another customer. As a result, the
20 tariff provision as written would put all responsibility on loan participants.
21

22 **Q. DO YOU HAVE ANY ADDITIONAL OBJECTIONS TO THE COMPANY'S**
23 **PROPOSED APPLICATION OF ITS NAS RIDER?**

24 A. Yes. Columbia proposes to divert the practice of applying pipeline refunds to the
25 hardship fund to the unpaid balances of loan participants. I recommend that the historic
26 practice of using pipeline refunds to help support the hardship fund be continued and that
27 because the annual amount of pipeline refunds varies and is uncertain, this introduces
28 unnecessary record keeping and complexities to a loan program. Furthermore, such a
29 proposal may not be equitable to those new customers that elect to pay their extension
30 deposits upfront and thereby not participate in the loan program.
31

1 **Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS CONCERNING**
2 **YOUR PROPOSED ESTABLISHMENT OF A COLLABORATIVE STUDY**
3 **GROUP RELATING TO MAIN AND SERVICE LINE EXTENSIONS?**

4 A. Yes. I recommend that the study group explore additional ways and methods to
5 make the Company's line extension policy (Tariff Rule 8) more transparent. Currently,
6 the Tariff Rule 8 language is so broad and general, it is all but impossible for a
7 prospective customer, I&E, or any other parties, to evaluate the reasonableness, or
8 determination of a deposit required by the Company.

9
10 **Q. DO YOU HAVE ANY RECOMMENDATIONS RELATING TO THE**
11 **DETERMINATION OF LINE EXTENSION DEPOSIT REQUIREMENTS AS**
12 **SET FORTH IN TARIFF RULE 8?**

13 A. Yes. My review of the Company's discounted cash flow model used internally to
14 determine a given customer's or project's deposit requirement, which was provided in
15 response to Data Request I&E-RE-14-D, reveals an overstatement of deposit
16 requirements. Specifically, the Company's internal model assumes that all line extension
17 capital investment is 100% equity financed such that in developing annual anticipated
18 cash flows, income tax expense is calculated assuming 100% equity as opposed to
19 recognizing the Company's actual capital structure and tax deductibility of interest.¹²
20 This has the effect of artificially lowering future discounted cash contributions from the
21 customer thereby increasing any and all deposit requirements. The Company's cash flow
22 model should be modified, at a minimum, to reflect the actual approved capital structure
23 and incorporate a tax deductible provision for interest expense within the determination
24 of expected future discounted cash flows.

25
26 **Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**

27 A. Yes.

28
29 164360

¹² It should be noted that the discount factor utilized is the overall cost of capital, including debt.

APPENDIX A:

**Excerpt of Glenn A. Watkins
Direct Testimony in
Docket No. R-2010-2215623**

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25 **Q. DOES COLUMBIA'S PROPOSAL TO COLLECT ALL RESIDENTIAL BASE**
26 **RATE REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH**
27 **THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL**
28 **PRACTICES OF SUCH COMPETITIVE MARKETS?**

29 A. No. The most basic tenet of competition is that prices determined through a
30 competitive market ensure the most efficient allocation of society's resources. Because
31 public utilities are generally afforded monopoly status under the belief that resources are

1 better utilized without the duplication of the fixed facilities required to serve consumers,
2 a fundamental goal of regulatory policy is that regulation should serve as a surrogate for
3 competition to the greatest extent practical.⁹ As such, the pricing policy for a regulated
4 public utility should mirror those of competitive firms to the greatest extent practical.
5

6 **Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED**
7 **IN COMPETITIVE MARKETS.**

8 A. Economic theory tells us that efficient price signals result when prices are equal to
9 long-run marginal costs. It is well known that in the long-run all costs are variable and,
10 hence, efficient pricing results from the incremental variability of costs even though a
11 firm's short-run cost structure may include a high level of sunk or "fixed" costs or be
12 reflective of excess capacity. Indeed, competitive market-based prices are generally
13 structured based on usage, i.e. volume based pricing.
14

15 **Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING**
16 **SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS**
17 **COLUMBIA.**

18 A. Due to Columbia's investment in system infrastructure, there is no debate that
19 many of Columbia's costs are fixed in the short-run. However, as discussed above,
20 efficient competitive prices are established based on long-run costs, which are entirely
21 variable in nature.¹⁰

22 Marginal cost pricing only relates to efficiency. This pricing does not attempt to
23 always address fairness or equity. From a perspective of fair and equitable pricing of a
24 regulated monopoly's products and services, it is generally agreed that payments for a
25 good or service should be in accordance with the benefits received. In this regard, those
26 that receive more benefits should pay more in total than those who receive fewer
27 benefits. With respect to natural gas usage, the volume of consumption is the most

⁹ James C. Bonbright, et al Principles of Public Utility Rates at 141 (2d ed. 1988).

¹⁰ Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represent the most efficient utilization of resources.

1 direct, and perhaps best, indicator of benefits received, such that volumetric pricing
2 promotes the fairest pricing mechanism to customers and to the utility.

3 The above philosophy is, and has been, the belief of economists, regulators, and
4 the marketplace for many years. As an illustration, consider utility industry pricing in its
5 infancy (1800s). In the beginning, customers paid a fixed monthly fee and consumed as
6 much of the utility commodity/service as they desired (usually water). It soon became
7 apparent that the fixed monthly fee rate schedule was inefficient and unfair. Utilities
8 soon began metering their commodity/service and charging only for the amount actually
9 consumed. In this way, consumers receiving more benefits from the utility than others
10 paid more in total for the utility service because they used more of the commodity.

11 Perhaps most importantly is an acknowledgement and understanding that virtually
12 every capital intensive industry is faced with a high percentage of fixed costs in the
13 short-run. This includes the agricultural, energy, manufacturing and transportation
14 industries. Prices for competitive products and services in these industries are invariably
15 established on a volumetric basis, including those that were once regulated; e.g., airline
16 travel and rail service.

17 Accordingly, the position of Mr. Feingold that Columbia's fixed costs should be
18 recovered through fixed monthly charges, in my view is incorrect since pricing should
19 reflect long-run cost incidence wherein all costs are variable or volumetric in nature, and
20 that users requiring more of Columbia's products and services pay more than customers
21 who use less of these products and services.

22
23 **Q. COLUMBIA'S PROPOSED "LEVELIZED DISTRIBUTION CHARGE" HAS**
24 **BEEN REFERRED TO AS A "STRAIGHT-FIXED VARIABLE" RATE DESIGN**
25 **BY OTHER UTILITIES ADVOCATING THE COLLECTION OF NATURAL**
26 **GAS DISTRIBUTION REVENUES ENTIRELY FROM FIXED MONTHLY**
27 **CHARGES. PLEASE EXPLAIN WHERE THIS TERM ORIGINATED AND**
28 **HOW RATE STRUCTURE IS APPLIED?**

1 A. The straight-fixed variable ("SFV") term was coined and adopted by the FERC in
2 its famous Order 636 in which fixed pipeline costs are recovered through annual fixed
3 demand charges and none through variable usage charges.¹¹
4

5 **Q. PLEASE EXPLAIN WHY THE FERC ADOPTED ITS STRAIGHT-FIXED**
6 **VARIABLE RATE DESIGN IN ITS ORDER 636.**

7 A. FERC Order 636 had two primary goals. The first was to enhance gas
8 competition at the wellhead by completely unbundling the merchant and transportation
9 functions of pipelines.¹² The second goal was to encourage the increased consumption of
10 natural gas in the United States. In the introductory statement of the Order, the FERC
11 stated:

12 "The Commission's intent is to further facilitate the unimpeded operation
13 of market forces to stimulate the production of natural gas . . . [and
14 thereby] contribute to reducing our Nation's dependence upon imported
15 oil" [Order at 8].
16

17 With specific regard to the SFV rate design adopted in Order 636, the FERC stated:

18 "Moreover, the Commission's adoption of SFV should maximize pipeline
19 throughput over time by allowing gas to compete with alternate fuels on a
20 timely basis as the prices of alternate fuels change. The Commission
21 believes it is beyond doubt that it is in the national interest to promote the
22 use of clean and abundant gas over alternate fuels such as foreign oil.
23 SFV is the best method for doing that" [Order at 128-129].
24

25 **Q. HOW DOES FERC'S OBJECTIVE TO INCREASE NATURAL GAS**
26 **CONSUMPTION USING THE SFV RATE DESIGN COMPORT WITH THE**
27 **COMPANY'S CLAIM THAT A SIMILAR RATE STRUCTURE IS EFFICIENT**
28 **AND WILL PROMOTE CONSERVATION?**

29 A. The FERC's objective for SFV is diametrically in opposition to a claimed need
30 for a "Levelized Distribution Charge." That is, the Company claims that because retail

¹¹ Generally, fixed demand charges represent fixed monthly charges for a specified time period (usually one year) based on the customers' selected maximum daily delivery entitlement (demand). Important distinctions between "fixed" demand charges and fixed customer charges are: the demand charges vary by customer and are dependent on relative size during peak periods; and, may be offset by releasing (selling) unneeded reserve capacity.

¹² Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636, page 7.

1 rates have been historically volumetric based, there has been a disincentive for LDCs to
2 promote conservation or encourage reduced consumption of natural gas. As is clearly
3 discussed in the FERC Order, the price signal that results from SFV pricing is meant to
4 promote additional natural gas consumption, not reduce consumption. A rate structure,
5 therefore, that is based entirely on a fixed monthly customer charge sends an even
6 stronger price signal to consumers to use more natural gas. Indeed, a rate structure
7 comprised of fixed monthly customer charges is even more at odds with conservation and
8 efficient pricing than a demand charge based (true SFV such as the one adopted by the
9 FERC) rate structure. Whereas a demand charge rate does recognize relative customer
10 size and allows customers to decide how much service is desired, coupled with the ability
11 to shed revenue responsibility (through capacity release), such characteristics are not
12 present or possible with fixed customer charge pricing.
13

14 **Q. IN CASE IT IS NOT OBVIOUS, WHY DO THE TRUE SFV AND FIXED**
15 **CUSTOMER CHARGE RATE STRUCTURES PROMOTE ADDITIONAL**
16 **CONSUMPTION?**

17 A. These rate structures promote consumption because the consumers' price of
18 incremental consumption is de minimis, or at the very least, less than what an efficient
19 price structure would otherwise be. As discussed in its Order 636, The FERC's adoption
20 of the SFV pricing method was a result of national policy (primarily that of Congress) to
21 promote the additional use of domestic natural gas by promoting additional interruptible
22 (and incremental firm) gas usage. Furthermore, when Order 636 was issued, the electric
23 industry was actively promoting the need for additional natural gas supplies at lower
24 prices to fuel the need for additional capacity and movement away from its reliance on
25 coal and nuclear generation. As such, the FERC's SFV pricing mechanism greatly
26 reduced the price of incremental (additional) natural gas consumption thereby
27 significantly increasing the demand for, and use of natural gas in the United States
28 subsequent to 1992 (when Order 636 was issued).
29
30
31

1 Q. MR. WATKINS, A CUSTOMER'S TOTAL GAS BILL IS COMPRISED OF A
2 BASE RATE COMPONENT AND A GAS COMMODITY COST COMPONENT.
3 GAS COSTS ARE VOLUMETRICALLY PRICED AND REPRESENT THE
4 MAJORITY OF A CUSTOMER'S GAS BILL. DOES THE VOLUMETRIC
5 PRICING OF THE GAS COST COMPONENT OVERSHADOW THE NEED FOR
6 A PROPER PRIMARY SIGNAL FROM BASE RATES?

7 A. No. The rationale of the "Levelized Distribution Charge" pricing approach
8 implies that even though marginal rates may be inefficiently structured, this error is
9 acceptable due to other aspects within a customer's gas bill. To me, this argument is no
10 more plausible than establishing rates that provide for clearly excessive monopolistic
11 profits under the notion that the additional cost to consumers only represents a small
12 portion of their energy bills and/or cost of living.

13
14 Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY
15 REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION,
16 ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES
17 IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED
18 UTILITIES?

19 A. Yes. In competitive markets, consumers, by definition, have the ability to choose
20 various suppliers of goods and services. Such is obviously not the case with regulated
21 monopoly utilities. Consumers and the market have a clear preference for volumetric
22 pricing. Utility customers are not so fortunate in that the local utility is a monopolist.
23 The only reason utilities are able to achieve pricing structures with high fixed monthly
24 charges is due to their monopoly status. In my opinion, this is a critical consideration in
25 establishing utility pricing structures. That is, competitive markets and consumers in the
26 U.S. have demanded volumetric based prices for generations: a regulated utility's pricing
27 structure should not be allowed to counter the collective wisdom of markets and
28 consumers simply because of its market power.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket Nos. R-2012-2321748
	)	M-2012-2323645
Columbia Gas of Pennsylvania, Inc.	)	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 4, 2013

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINSVICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.**EDUCATION**

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE**I. Public Utility Regulation**

- A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

- B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

- C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.
- D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.
- E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

- A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.
- B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)

Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)

Member, American Water Works Association

National Association of Business Economists

Richmond Association of Business Economists

National Economics Honor Society

COLUMBIA GAS OF PENNSYLVANIA, INC.
OCA ADJUSTED PEAK & AVERAGE
RATE OF RETURN BY CLASS @ CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) \$	RS/RDS (D) \$	SGS/SGDS (E) \$	LGS (F) \$	SDS (G) \$	LDS (H) \$	MDS (I) \$
1	TOTAL REVENUE		379,306,896	274,373,270	75,451,790	5,588,480	9,530,454	12,860,564	1,502,338
2	PRODUCTS PURCHASED		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES		137,753,458	99,466,463	22,371,945	1,365,199	4,346,811	10,060,033	143,007
4	DEPRECIATION & AMORTIZATION		41,961,336	27,929,447	7,456,969	348,065	1,968,630	4,245,375	12,852
5	TAXES OTHER THAN INCOME		3,688,203	2,481,247	688,805	33,101	154,191	329,127	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		333,601,624	238,197,633	68,119,115	5,771,494	6,469,631	14,634,534	409,216
7	OPERATING INCOME BEFORE TAXES		45,705,272	36,175,637	7,332,675	(183,014)	3,060,823	(1,773,970)	1,093,122
8	INCOME TAXES		4,442,828	5,681,259	320,981	(217,696)	544,810	(2,336,662)	450,137
9	INVESTMENT TAX CREDIT	12	(360,239)	(232,783)	(65,063)	(3,210)	(18,513)	(40,570)	(101)
10	NET INCOME TAXES		4,082,589	5,448,476	255,918	(220,906)	526,297	(2,377,233)	450,036
11	OPERATING INCOME		41,622,683	30,727,161	7,076,757	37,892	2,534,526	603,262	643,086
12	RATE BASE		1,011,680,660	648,732,767	191,773,619	10,147,362	50,061,579	110,739,680	225,653
13	RATE OF RETURN EARNED ON RATE BASE		4.114%	4.736%	3.690%	0.373%	5.063%	0.545%	284.989%
14	UNITIZED RETURN		1.00	1.15	0.90	0.09	1.23	0.13	69.27

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

LINE NO.	ACCT. NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				\$	\$	\$	\$	\$	\$	\$
1	301-305	INTANGIBLE PLANT	11	13,197,924	8,525,463	2,378,266	117,066	681,013	1,492,421	3,695
2	350-362	UNDERGROUND STORAGE PLANT	25	6,014,913	4,184,996	1,703,243	118,915	-	-	7,759
		<u>DISTRIBUTION PLANT</u>								
3	374.10	LAND - CITY GATE & M/L IND M&R	5	188,844	100,552	39,472	2,347	14,263	32,209	-
4	374.20	LAND - OTHER DISTRIBUTION	5	480,964	256,094	100,531	5,978	36,327	82,033	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	5	95,361	50,776	19,932	1,185	7,203	16,265	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	5	1,783,038	949,397	372,691	22,163	134,673	304,115	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		3	-	-	-	-	-	3
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	5	13	8	3	-	-	2	-
9	374.50	RIGHTS OF WAY	5	3,231,844	1,720,828	675,520	40,172	244,101	551,223	-
10	374.50	DIRECT - RIGHTS OF WAY		1,195	-	-	-	-	-	1,195
11	375.20	M & R STRUCTURES - CITY GATE	5	813,126	432,957	169,960	10,107	61,415	138,687	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	5	4,012	2,136	839	50	303	684	-
13	375.40	M & R STRUCTURES - REGULATING	5	2,714,399	1,445,309	567,364	33,740	205,019	462,968	-
14	375.60	M & R STRUCTURES - DIST. IND M & R	17	87,692	(0)	58,671	5,195	17,108	6,718	-
15	375.70	M & R STRUCTURES - OTHER	11	4,150,247	2,680,935	747,875	36,813	214,153	469,310	1,162
16	375.71	M & R STRUCTURES - OTHER LEASED	11	1,031,960	666,615	185,959	9,154	53,249	116,694	289
17	375.80	M & R STRUCTURES - COMMUNICATION	5	16,515	8,794	3,452	205	1,247	2,817	-
18	376.00	MAINS	5	811,843,757	432,274,327	169,691,582	10,091,218	61,318,559	138,468,071	-
19	376.00	DIRECT - MAINS		98,881	-	-	-	-	-	98,881
20	376.08	MAINS-CSL REPLACEMENTS	5	23,059,830	12,278,437	4,819,966	286,634	1,741,709	3,933,085	-
21	376.30	MAINS-BARE STEEL	5	75,183,814	40,032,374	15,714,921	934,535	5,678,634	12,823,351	-
22	376.30	DIRECT - MAINS-BARE STEEL		118,511	-	-	-	-	-	118,511
23	376.80	MAINS-CAST IRON	5	739,405	393,704	154,551	9,191	55,847	126,113	-
24	378.10	M & R EQUIP - GENERAL	5	58,867	31,345	12,305	732	4,446	10,040	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	5	18,916,204	10,072,122	3,953,865	235,128	1,428,741	3,226,348	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		1,178	-	-	-	-	-	1,178
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	5	486,506	259,045	101,690	6,047	36,746	82,979	-
28	379.10	M & R EQUIP - CITY GATE	5	147,820	78,708	30,897	1,837	11,165	25,212	-
29	379.11	M & R EQUIP - EXCHANGE GAS	5	5,974	3,181	1,249	74	451	1,019	-
30	380.00	SERVICES	15	373,962,974	341,981,661	31,098,761	272,993	418,839	190,721	-
31	380.00	DIRECT - SERVICES		37,630	-	-	-	-	-	37,630
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	34,301,875	25,721,261	8,124,056	94,673	278,874	78,551	4,459
34	381.10	AUTOMATIC METER READING	16	20,548,041	15,407,948	4,866,598	56,713	167,056	47,055	2,671
35	382.00	METER INSTALLATIONS	16	35,468,816	26,596,292	8,400,435	97,894	288,362	81,224	4,611
36	383.00	HOUSE REGULATORS	16	10,741,363	8,054,411	2,543,984	29,648	87,327	24,598	1,396
37	384.00	HOUSE REG INSTALLATIONS	16	3,864,772	2,897,999	915,333	10,667	31,421	8,850	502
38	385.00	IND M&R EQUIPMENT	17	5,355,556	-	3,583,135	317,263	1,044,869	410,289	-
39	385.00	DIRECT - IND M&R EQUIPMENT		122,846	-	-	-	-	-	122,846
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	1,356,628	-	907,652	80,367	264,678	103,931	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	16,603	10,725	2,992	147	857	1,878	5
42	387.20	OTHER EQUIP ODORIZATION	11	121,943	78,771	21,974	1,082	6,292	13,789	34
43	387.42	OTHER EQUIP RADIO	11	130,407	84,239	23,499	1,157	6,729	14,746	37
44	387.44	OTHER EQUIP COMMUNICATION	11	664,599	429,311	119,761	5,895	34,293	75,153	186
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	259,436	167,588	46,750	2,301	13,387	29,337	73
46		TOTAL DISTRIBUTION PLANT		1,432,213,452	925,157,849	258,078,221	12,703,303	73,908,343	161,960,066	395,670
47	389-398	GENERAL PLANT	11	25,681,927	16,589,754	4,627,883	227,799	1,325,187	2,904,112	7,191
48		TOTAL GROSS PLANT		1,477,108,215	954,468,062	266,787,613	13,167,082	75,914,543	166,356,599	414,315

COLUMBIA GAS OF PENNSYLVANIA, INC.
OCA ADJUSTED PEAK & AVERAGE
DEPRECIATION RESERVE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	RS/RDS (E) \$	SGS/SGDS (F) \$	LGS (G) \$	SDS (H) \$	LDS (I) \$	MDS (J) \$
1	301-305	INTANGIBLE PLANT	11	4,670,206	3,016,813	841,571	41,425	240,983	528,107	1,308
2	350-362	UNDERGROUND STORAGE PLANT	25	1,332,255	926,943	377,255	26,339	-	-	1,719
<u>DISTRIBUTION PLANT</u>										
3	374.10	LAND - CITY GATE & M/L IND M&R	5	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	5	(24,311)	(12,945)	(5,082)	(302)	(1,836)	(4,147)	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	5	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	5	635,353	338,300	132,801	7,897	47,988	108,366	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		1	-	-	-	-	-	1
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	5	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	5	1,495,661	796,380	312,623	18,591	112,967	255,100	-
10	374.50	DIRECT - RIGHTS OF WAY		664	-	-	-	-	-	664
11	375.20	M & R STRUCTURES - CITY GATE	5	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	5	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	5	789,197	420,216	164,958	9,810	59,608	134,605	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	71,206	-	47,640	4,218	13,892	5,455	-
15	375.70	M & R STRUCTURES - OTHER	11	2,143,906	1,384,899	386,332	19,016	110,626	242,433	600
16	375.71	M & R STRUCTURES - OTHER LEASED	11	971,923	627,833	175,141	8,621	50,151	109,905	272
17	375.80	M & R STRUCTURES - COMMUNICATION	5	5,681	3,025	1,187	71	429	969	-
18	376.00	MAINS	5	121,479,094	64,682,758	25,391,560	1,509,985	9,175,316	20,719,474	-
19	376.00	DIRECT - MAINS		58,002	-	-	-	-	-	58,002
20	376.08	MAINS-CSL REPLACEMENTS	5	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	5	45,736,016	24,352,599	9,559,742	568,499	3,454,441	7,800,735	-
22	376.30	DIRECT - MAINS-BARE STEEL		96,966	-	-	-	-	-	96,966
23	376.80	MAINS-CAST IRON	5	12,008	6,394	2,510	149	907	2,048	-
24	378.10	M & R EQUIP - GENERAL	5	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	5	6,461,419	3,440,447	1,350,566	80,315	488,031	1,102,060	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		870	-	-	-	-	-	870
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	5	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	5	94,719	50,434	19,798	1,177	7,154	16,155	-
29	379.11	M & R EQUIP - EXCHANGE GAS	5	-	-	-	-	-	-	-
30	380.00	SERVICES	15	101,680,586	92,984,863	8,455,758	74,227	113,882	51,857	-
31	380.00	DIRECT - SERVICES		21,869	-	-	-	-	-	21,869
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	14,998,136	11,246,352	3,552,159	41,395	121,935	34,346	1,950
34	381.10	AUTOMATIC METER READING	16	4,440,562	3,329,755	1,051,703	12,256	36,102	10,169	577
35	382.00	METER INSTALLATIONS	16	10,435,222	7,824,851	2,471,478	28,801	84,838	23,897	1,357
36	383.00	HOUSE REGULATORS	16	2,868,259	2,150,764	679,319	7,916	23,319	6,568	373
37	384.00	HOUSE REG INSTALLATIONS	16	2,788,621	2,091,048	660,457	7,697	22,672	6,386	363
38	385.00	IND M&R EQUIPMENT	17	3,181,978	-	2,128,902	188,500	620,804	243,771	-
39	385.00	DIRECT - IND M&R EQUIPMENT		44,342	-	-	-	-	-	44,342
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	73,950	0	49,476	4,381	14,428	5,665	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	545,616	352,452	98,320	4,840	28,154	61,698	153
46		TOTAL DISTRIBUTION PLANT		321,107,516	216,070,425	56,687,348	2,598,061	14,585,808	30,937,517	228,358
47	389-398	GENERAL PLANT	11	15,890,423	10,264,737	2,863,454	140,948	819,946	1,796,889	4,449
48		TOTAL DEPRECIATION RESERVE		343,000,400	230,278,918	60,769,628	2,806,772	15,646,736	33,262,512	235,834

COLUMBIA GAS OF PENNSYLVANIA, INC.
OCA ADJUSTED PEAK & AVERAGE
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

Schedule GAW-2
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LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	RS/RDS (E) \$	SGS/SGDS (F) \$	LGS (G) \$	SDS (H) \$	LDS (I) \$	MDS (J) \$
1	301-305	INTANGIBLE PLANT	11	1,756,935	1,134,927	316,600	15,584	90,658	198,674	492
2	350-362	UNDERGROUND STORAGE PLANT	25	163,888	114,014	46,403	3,240	-	-	211
		<u>DISTRIBUTION PLANT</u>								
3	374.10	LAND - CITY GATE & M/L IND M&R	5	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	5	-	-	-	-	-	-	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	5	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	5	35,574	18,942	7,436	442	2,687	6,068	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		0	-	-	-	-	-	0
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	5	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	5	43,000	22,896	8,988	535	3,248	7,334	-
10	374.50	DIRECT - RIGHTS OF WAY		16	-	-	-	-	-	16
11	375.20	M & R STRUCTURES - CITY GATE	5	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	5	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	5	81,608	43,453	17,058	1,014	6,164	13,919	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	973	0	651	58	190	75	-
15	375.70	M & R STRUCTURES - OTHER	11	161,680	104,440	29,135	1,434	8,343	18,283	45
16	375.71	M & R STRUCTURES - OTHER LEASED	11	182,501	117,890	32,887	1,619	9,417	20,637	51
17	375.80	M & R STRUCTURES - COMMUNICATION	5	342	182	72	4	26	58	-
18	376.00	MAINS	5	16,635,509	8,857,743	3,477,154	206,779	1,256,480	2,837,352	-
19	376.00	DIRECT - MAINS		1,641	-	-	-	-	-	1,641
20	376.08	MAINS-CSL REPLACEMENTS	5	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	5	1,725,309	918,658	360,624	21,446	130,313	294,269	-
22	376.30	DIRECT - MAINS-BARE STEEL		2,501	-	-	-	-	-	2,501
23	376.80	MAINS-CAST IRON	5	409	218	86	5	31	70	-
24	378.10	M & R EQUIP - GENERAL	5	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	5	563,688	300,141	117,822	7,007	42,575	96,143	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		29	-	-	-	-	-	29
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	5	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	5	5,023	2,675	1,050	62	379	857	-
29	379.11	M & R EQUIP - EXCHANGE GAS	5	-	-	-	-	-	-	-
30	380.00	SERVICES	15	10,309,953	9,428,246	857,376	7,526	11,547	5,258	-
31	380.00	DIRECT - SERVICES		963	-	-	-	-	-	963
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	835,931	626,823	197,982	2,307	6,796	1,914	109
34	381.10	AUTOMATIC METER READING	16	1,778,260	1,333,428	421,163	4,908	14,457	4,072	231
35	382.00	METER INSTALLATIONS	16	707,167	530,269	167,485	1,952	5,749	1,619	92
36	383.00	HOUSE REGULATORS	16	284,993	213,702	67,498	787	2,317	653	37
37	384.00	HOUSE REG INSTALLATIONS	16	72,465	54,338	17,163	200	589	166	9
38	385.00	IND M&R EQUIPMENT	17	245,096	0	163,982	14,520	47,818	18,777	-
39	385.00	DIRECT - IND M&R EQUIPMENT		4,644	-	-	-	-	-	4,644
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	4,212	-	2,818	250	822	323	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	49,407	31,916	8,903	438	2,549	5,587	14
46		TOTAL DISTRIBUTION PLANT		33,732,894	22,605,959	5,957,330	273,292	1,552,498	3,333,433	10,382
47	389-398	GENERAL PLANT	11	1,443,308	932,334	260,084	12,802	74,475	163,209	404
48		NET DEPRECIATION & AMORTIZATION EXPENSE		37,097,005	24,787,235	6,580,416	304,918	1,717,630	3,695,316	11,490
49		AMORTIZATION OF NET NEGATIVE SALVAGE	11	4,864,331	3,142,212	876,552	43,147	251,000	550,059	1,362
50		TOTAL AMORTIZATION AND DEPRECIATION EXPENSE		41,961,336	27,929,447	7,456,969	348,065	1,968,630	4,245,375	12,852

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

LINE NO.	ACCT NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				\$	\$	\$	\$	\$	\$	\$
<u>PROPOSED OPERATING REVENUE</u>										
SALES REVENUE										
1	480/481	SALES BASE REVENUE		192,284,674	157,005,586	33,128,598	2,130,998	-	-	19,492
2		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
3		STAS REVENUE		-	-	-	-	-	-	-
4		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
5		GAS PROCUREMENT REVENUE	2	455,287	332,745	118,253	13,410	-	-	879
6		GAS COST REVENUE		<u>141,900,550</u>	<u>102,129,786</u>	<u>35,494,009</u>	<u>4,025,130</u>	-	-	<u>251,625</u>
7		TOTAL SALES REVENUE		344,807,834	269,140,819	69,225,481	6,169,538	-	-	271,996
TRANSPORTATION REVENUE										
8	489 00	TRANSPORTATION BASE REVENUE		94,941,706	57,083,115	18,245,424	-	9,900,113	9,492,046	221,008
9		USP REVENUE		2,549,024	2,549,024	-	-	-	-	-
10		STAS REVENUE		-	-	-	-	-	-	-
11		FLEX REVENUE		4,613,061	-	32,146	-	201,904	3,369,813	1,009,198
12		GAS COST REVENUE		<u>8,298,077</u>	<u>6,190,690</u>	<u>2,107,387</u>	-	-	-	-
13		TOTAL TRANSPORTATION REVENUE		110,401,868	65,822,829	20,384,957	-	10,102,017	12,861,859	1,230,206
MISCELLANEOUS REVENUE										
14	487 00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,614	1,284
15	488 00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
16	493 00	RENTS	6	173,011	157,613	15,151	33	173	38	4
17	495 00	OTHER	6	<u>144,725</u>	<u>131,845</u>	<u>12,674</u>	<u>28</u>	<u>145</u>	<u>32</u>	<u>3</u>
18		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,189,320	197,302	1,033	10,125	9,716	1,294
19		TOTAL PROPOSED OPERATING REVENUE		<u>456,618,492</u>	<u>336,152,969</u>	<u>89,807,740</u>	<u>6,170,570</u>	<u>10,112,142</u>	<u>12,871,575</u>	<u>1,503,496</u>
<u>CURRENT OPERATING REVENUE</u>										
SALES REVENUE										
20	480/481	SALES BASE REVENUE		138,032,974	112,543,257	23,906,093	1,564,132	-	-	19,492
21		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
22		STAS REVENUE		(181,366)	(151,797)	(27,731)	(1,815)	-	-	(23)
23		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
24		GAS COST REVENUE		<u>141,900,550</u>	<u>102,129,786</u>	<u>35,494,009</u>	<u>4,025,130</u>	-	-	<u>251,625</u>
25		TOTAL SALES REVENUE		289,909,481	224,193,948	59,856,992	5,587,447	-	-	271,094
TRANSPORTATION REVENUE										
26	489 00	TRANSPORTATION BASE REVENUE		72,604,033	40,286,371	13,273,361	-	9,329,247	9,492,046	221,008
27		USP REVENUE		2,549,024	2,549,024	-	-	-	-	-
28		STAS REVENUE		(75,570)	(38,083)	(15,398)	-	(10,822)	(11,011)	(256)
29		FLEX REVENUE		4,613,061	-	32,146	-	201,904	3,369,813	1,009,198
30		GAS COST REVENUE		<u>8,298,077</u>	<u>6,190,690</u>	<u>2,107,387</u>	-	-	-	-
31		TOTAL TRANSPORTATION REVENUE		87,988,625	48,990,002	15,397,496	-	9,520,329	12,850,848	1,229,950
MISCELLANEOUS REVENUE										
32	487 00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,614	1,284
33	488 00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
34	493 00	RENTS	6	173,011	157,613	15,151	33	173	38	4
35	495 00	OTHER	6	<u>144,725</u>	<u>131,845</u>	<u>12,674</u>	<u>28</u>	<u>145</u>	<u>32</u>	<u>3</u>
36		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,189,320	197,302	1,033	10,125	9,716	1,294
37		TOTAL CURRENT OPERATING REVENUE		<u>379,306,896</u>	<u>274,373,270</u>	<u>75,451,790</u>	<u>5,588,480</u>	<u>9,530,454</u>	<u>12,880,564</u>	<u>1,502,338</u>

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

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	RS/RDS (E) \$	SGS/SGDS (F) \$	LGS (G) \$	SDS (H) \$	LDS (I) \$	MDS (J) \$
<u>PURCHASED GAS EXPENSES</u>										
1		GAS PURCHASED COST		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
2	807.00	PURCHASED GAS EXPENSE	4	1,036,138	747,242	259,387	27,769	-	-	1,741
3	807.00	GAS PROCUREMENT EXPENSE	4	465,287	335,556	116,480	12,470	-	-	782
4		TOTAL PURCHASED GAS		151,700,052	109,403,274	37,977,263	4,065,368	-	-	254,147
<u>UNDERGROUND STORAGE OPERATIONS EXPENSES</u>										
5	816.00	WELLS	25	10,754	7,482	3,045	213	-	-	14
6	817.00	LINES	25	37,625	26,178	10,654	744	-	-	49
7	818.00	COMPRESSOR STATION	25	150,458	104,684	42,605	2,975	-	-	194
8	820.00	M & R	25	15,840	11,021	4,485	313	-	-	20
9	821.00	PURIFICATION	25	3,082	2,145	873	61	-	-	4
10	823.00	GAS LOSSES	25	2,052	1,428	581	41	-	-	3
11	825.00	STORAGE WELL ROYALTIES	25	5,977	4,159	1,693	118	-	-	8
12		TOTAL UNDERGROUND STORAGE OPERATIONS		225,787	157,096	63,936	4,464	-	-	291
<u>UNDERGROUND STORAGE MAINTENANCE EXPENSES</u>										
13	832.00	WELLS	25	7,823	5,443	2,215	155	-	-	10
14	834.00	COMPRESSOR STATION	25	6,230	4,335	1,764	123	-	-	8
15	836.00	PURIFICATION	25	6,789	4,724	1,923	134	-	-	9
16		TOTAL UNDERGROUND STORAGE MAINTENANCE		20,843	14,502	5,902	412	-	-	27
17		TOTAL UNDERGROUND STORAGE		246,630	171,598	69,838	4,876	-	-	318
<u>DISTRIBUTION OPERATIONS EXPENSES</u>										
18	870.00	SUPERVISION & ENGINEERING	18	4,666,895	3,016,074	920,125	40,135	223,264	466,456	840
19	871.00	LOAD DISPATCHING	13	124,644	66,352	26,047	1,549	9,412	21,254	30
20	874.00	MAINS & SERVICES	14	10,868,086	6,993,939	1,873,115	98,030	585,355	1,315,473	2,174
21	875.00	M & R - GENERAL	13	590,194	314,178	123,333	7,336	44,566	100,640	142
22	876.00	M & R - INDUSTRIAL	17	245,982	-	164,574	14,572	47,991	18,845	-
23	878.00	METERS & HOUSE REGULATORS	16	2,455,745	1,841,440	581,619	6,778	19,965	5,624	319
24	879.00	CUSTOMER INSTALLATIONS	16	4,813,089	3,609,095	1,139,932	13,284	39,130	11,022	626
25	880.00	OTHER	18	4,881,051	3,154,477	962,348	41,977	233,510	487,861	879
26	881.00	RENTS	18	273,398	176,689	53,903	2,351	13,079	27,326	49
27		TOTAL DISTRIBUTION OPERATIONS		28,919,083	19,172,244	5,844,995	226,013	1,216,272	2,454,501	5,058
<u>DISTRIBUTION MAINTENANCE EXPENSES</u>										
28	885.00	SUPERVISION & ENGINEERING	18	51,399	33,218	10,134	442	2,459	5,137	9
29	886.00	STRUCTURES AND IMPROVEMENTS	13	52,374	27,880	10,945	651	3,955	8,931	13
30	887.00	MAINS	13	10,193,632	5,426,376	2,130,163	126,707	769,721	1,738,218	2,447
31	889.00	M & R - GENERAL	13	609,180	324,285	127,300	7,572	45,999	103,877	146
32	890.00	M & R - INDUSTRIAL	17	127,109	-	85,042	7,530	24,799	9,738	-
33	892.00	SERVICES	15	3,008,381	2,751,104	250,177	2,196	3,369	1,534	-
34	893.00	METERS & HOUSE REGULATORS	16	286,063	214,505	67,751	790	2,326	655	37
35	894.00	OTHER EQUIPMENT	18	796,193	514,555	156,977	6,847	38,090	79,579	143
36		TOTAL DISTRIBUTION MAINTENANCE		15,124,330	9,291,923	2,838,490	152,735	890,718	1,947,670	2,795
37		TOTAL DISTRIBUTION		44,043,414	28,464,167	8,683,485	378,748	2,106,990	4,402,171	7,853

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

LINE NO.	ACCT NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				\$	\$	\$	\$	\$	\$	\$
<u>CUSTOMER ACCOUNTS EXPENSES</u>										
1	901.00	SUPERVISION	6	-	-	-	-	-	-	-
2	902.00	METER READING	6	2,126,147	1,936,920	186,187	404	2,126	468	43
3	903.00	COLLECTING-DELINQUENT ACCTS	6	1,072,108	976,690	93,885	204	1,072	236	21
4	903.00	COLLECTING-CURRENT ACCTS	6	7,959	7,251	697	2	8	2	0
5	903.00	BILLING & ACCOUNTING	6	5,797,611	5,281,623	507,697	1,102	5,798	1,276	116
6	903.00	RENDERING BILLS	6	2,484,720	2,263,580	217,587	472	2,485	547	50
7	904.00	UNCOLLECTIBLES-DIS REVENUE	7	3,037,943	2,399,671	638,272	-	-	-	-
8	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	8	38,961	-	3,480	6,792	11,573	15,621	1,495
9	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	23	1,848,276	1,363,658	484,618	-	-	-	-
10	904.00	DIRECT USP UNCOLLECTIBLES		8,469,295	8,469,295	-	-	-	-	-
11	905.00	MISCELLANEOUS	6	17,448	15,895	1,528	3	17	4	0
12	921.00	OFFICE SUPPLIES & EXPENSES	6	4,212	3,837	369	1	4	1	-
13		TOTAL CUSTOMER ACCOUNTS		24,904,680	22,718,421	2,134,318	8,979	23,083	18,154	1,725
<u>CUST SERVICE & INFORMATION EXPENSES</u>										
14	907.00	SUPERVISION	6	-	-	-	-	-	-	-
15	908.00	CUSTOMER ASSISTANCE	6	613,463	558,877	53,721	117	614	135	-
16	908.00	DIRECT USP/LIURP/HEEP		2,388,776	2,388,776	-	-	-	-	-
17	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	38,185	34,786	3,344	7	38	8	1
18	910.00	MISCELLANEOUS	6	600,792	547,321	52,611	114	601	132	12
19	910.00	LARGE CUSTOMER RELATIONS	21	986,406	0	113,091	257,600	-	552,890	62,824
20	921.00	OFFICE SUPPLIES & EXPENSES	6	9,085	8,277	796	2	9	2	-
21	931.00	RENTS - GENERAL	6	140	128	12	-	-	-	-
22		TOTAL CUST SERVICE & INFORMATION		4,636,846	3,538,165	223,575	257,840	1,262	553,168	62,837
<u>SALES EXPENSES</u>										
23	912.00	DEMONSTRATION	6	650,917	592,985	57,001	124	651	143	13
24	913.00	ADVERTISING	6	128,865	117,396	11,285	25	129	28	3
25		TOTAL SALES		779,782	710,381	68,286	148	780	172	16
<u>ADMINISTRATIVE AND GENERAL EXPENSES</u>										
26	920.00	SALARIES	19	3,908,071	2,724,863	675,588	44,318	137,369	321,165	4,768
27	921.00	OFFICE SUPPLIES & EXPENSES	19	2,016,774	1,406,175	348,640	22,870	70,890	165,739	2,461
28	922.00	ADMIN. EXPENSE TRANSFERRED	19	-	-	-	-	-	-	-
29	923.00	OUTSIDE SERVICES EMPLOYED	19	41,245,654	28,758,120	7,130,136	467,726	1,449,785	3,389,568	50,320
30	924.00	PROPERTY INSURANCE	19	157,493	109,810	27,226	1,786	5,536	12,943	192
31	925.00	INJURIES AND DAMAGES	19	3,725,912	2,597,855	644,098	42,252	130,966	306,196	4,546
32	926.00	EMPLOYEE PENSIONS & BENEFITS	24	8,294,725	5,586,000	1,594,661	69,427	339,586	702,397	2,654
33	928.00	REGULATORY COMMISSION EXPENSES	19	1,428,131	995,750	246,881	16,195	50,199	117,364	1,742
34	930.00	MISCELLANEOUS GENERAL	19	568,725	396,538	98,315	6,449	19,991	46,738	694
35	931.00	RENTS-GENERAL	19	295,199	205,824	51,031	3,348	10,376	24,259	360
36		TOTAL ADMINISTRATIVE & GENERAL		61,640,682	42,780,935	10,816,577	674,370	2,214,696	5,086,368	67,736
37		TOTAL O & M EXPENSES		287,952,086	207,786,939	59,973,341	5,390,329	4,346,811	10,060,033	394,632

COLUMBIA GAS OF PENNSYLVANIA, INC.
OCA ADJUSTED PEAK & AVERAGE
TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

LINE NO.	ACCT NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		<u>FEDERAL TAXES</u>		\$	\$	\$	\$	\$	\$	\$
1	408.00	FEDERAL UNEMPLOYMENT	24	45,196	30,437	8,689	378	1,850	3,827	15
2	408.00	FICA	24	2,190,869	1,475,419	421,195	18,338	89,694	185,523	701
3		TOTAL FEDERAL TAXES		<u>2,236,065</u>	<u>1,505,856</u>	<u>429,884</u>	<u>18,716</u>	<u>91,545</u>	<u>189,350</u>	<u>716</u>
		<u>STATE TAXES</u>								
4	408.00	PA PROPERTY TAXES	11	642,142	414,804	115,714	5,696	33,135	72,613	180
5	408.00	PA STATE UNEMPLOYMENT	24	161,920	109,043	31,129	1,355	6,629	13,711	52
6	408.00	STATE CAPITAL STOCK TAX	11	-	-	-	-	-	-	-
7	408.00	LICENSE AND FRANCHISE TAX	11	6,251	4,038	1,126	55	323	707	2
8	408.00	STATE SALES AND USE TAX	19	614,394	428,380	106,210	6,967	21,596	50,491	750
9	408.00	OTHER	19	27,431	19,126	4,742	311	964	2,254	34
10		TOTAL STATE TAXES		<u>1,452,138</u>	<u>975,392</u>	<u>258,922</u>	<u>14,385</u>	<u>62,646</u>	<u>139,777</u>	<u>1,017</u>
11		TOTAL TAXES OTHER THAN INCOME		<u>3,688,203</u>	<u>2,481,247</u>	<u>688,805</u>	<u>33,101</u>	<u>154,191</u>	<u>329,127</u>	<u>1,732</u>

COLUMBIA GAS OF PENNSYLVANIA, INC.
OCA ADJUSTED PEAK & AVERAGE
RATE BASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	RS/RDS (E) \$	SGS/SGDS (F) \$	LGS (G) \$	SDS (H) \$	LDS (I) \$	MDS (J) \$
1	101-107	GROSS PLANT		1,477,108,215	954,468,062	266,787,613	13,167,082	75,914,543	166,356,599	414,315
2	117.00	GAS STORED UNDERGROUND - NON CURRENT	25	3,794,990	2,640,440	1,074,627	75,027	-	-	4,896
3	108-111	DEPRECIATION RESERVE		(343,000,400)	(230,278,918)	(60,769,628)	(2,806,772)	(15,646,736)	(33,262,512)	(235,834)
4	117.00	GAS LOST-UNDERGROUND STORAGE	1	(163,458)	(99,510)	(37,984)	(1,944)	(8,717)	(15,303)	-
5		NET PLANT		1,137,739,347	726,730,075	207,054,628	10,433,393	60,259,090	133,078,784	183,377
<u>WORKING CAPITAL</u>										
6	154.00	MATERIALS & SUPPLIES	11	663,015	428,288	119,475	5,881	34,212	74,974	186
7	164.00	GAS STORED UNDERGROUND - FSS	25	74,526,147	51,853,057	21,103,569	1,473,382	-	-	96,139
8	165.00	PREPAYMENTS	19	1,651,928	1,151,790	285,569	18,733	58,065	135,755	2,015
9		CASH WORKING CAPITAL - GAS PURCHASES	4	-	-	-	-	-	-	-
10		CASH WORKING CAPITAL - ALL OTHER	19	-	-	-	-	-	-	-
11		TOTAL WORKING CAPITAL		76,841,090	53,433,136	21,508,613	1,497,996	92,277	210,729	98,340
<u>DEFERRED INCOME TAXES</u>										
12	190.00	ACCUMULATED DEF INCOME TAX	12	3,351,427	2,165,659	605,301	29,861	172,230	377,438	938
13	282.00	ACCUMULATED DEF INCOME TAX	12	(203,338,966)	(131,395,606)	(36,725,051)	(1,811,750)	(10,449,590)	(22,900,034)	(56,935)
14	283.00	ACCUMULATED DEF INCOME TAX	12	(23,454)	(15,156)	(4,236)	(209)	(1,205)	(2,641)	(7)
15		TOTAL DEFERRED INCOME TAXES		(200,010,993)	(129,245,103)	(36,123,985)	(1,782,098)	(10,278,565)	(22,525,238)	(56,003)
16	235.00	CUSTOMER DEPOSITS	9	(2,671,287)	(2,044,844)	(626,444)	-	-	-	-
17	252.00	CUSTOMER ADVANCES	11	(217,497)	(140,497)	(39,193)	(1,929)	(11,223)	(24,595)	(61)
18		RATE BASE		1,011,680,660	648,732,767	191,773,619	10,147,362	50,061,579	110,739,680	225,653

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

LINE NO.	ACCT NO. (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) \$	RS/RDS (D) \$	SGS/SGDS (E) \$	LGS (F) \$	SDS (G) \$	LDS (H) \$	MDS (I) \$
<u>STATE INCOME TAX</u>									
1	OPERATING INCOME BEFORE TAXES		45,705,272	36,175,637	7,332,675	(183,014)	3,060,823	(1,773,970)	1,093,122
2	STATUTORY ADJUSTMENTS	12	(37,630,943)	(24,316,739)	(6,796,525)	(335,292)	(1,933,854)	(4,237,997)	(10,537)
3	INTEREST ON DEBT		(26,607,201)	(17,061,672)	(5,043,646)	(266,876)	(1,316,620)	(2,912,454)	(5,935)
4	PA BONUS DEPRECIATION ADJUSTMENT	12	(5,114,711)	(3,305,075)	(923,768)	(45,572)	(262,845)	(576,019)	(1,432)
5	STATE TAXABLE INCOME		(23,647,583)	(8,507,848)	(5,431,264)	(830,754)	(452,496)	(9,500,439)	1,075,218
6	NET OPERATING LOSS DEDUCTION	12	-	-	-	-	-	-	-
	STATE TAXABLE INCOME		(23,647,583)	(8,507,848)	(5,431,264)	(830,754)	(452,496)	(9,500,439)	1,075,218
7	STATE NET INCOME TAX @ 9.99%		(2,362,394)	(849,934)	(542,583)	(82,992)	(45,204)	(949,094)	107,414
8	DEFERRED INCOME TAXES	12	1,566,210	1,012,069	282,873	13,955	80,488	176,387	439
9	STATE INCOME TAX		(796,184)	162,135	(259,710)	(69,037)	35,283	(772,707)	107,853
<u>FEDERAL INCOME TAX</u>									
10	OPERATING INCOME BEFORE TAXES		45,705,272	36,175,637	7,332,675	(183,014)	3,060,823	(1,773,970)	1,093,122
11	STATE NET INCOME TAX (LINE 7)		2,362,394	849,934	542,583	82,992	45,204	949,094	(107,414)
12	STATUTORY ADJUSTMENTS (LINES 2 & 3)	12	(64,238,144)	(41,378,410)	(11,840,171)	(602,167)	(3,250,474)	(7,150,450)	(16,471)
13	FEDERAL TAXABLE INCOME		(16,170,478)	(4,352,839)	(3,964,913)	(702,189)	(144,446)	(7,975,327)	969,236
14	FEDERAL INCOME TAX @ 35%		(5,659,667)	(1,523,494)	(1,387,719)	(245,766)	(50,556)	(2,791,364)	339,233
15	DEFERRED INCOME TAXES	12	16,164,641	10,445,429	2,919,496	144,027	830,701	1,820,462	4,526
16	TAX REFUND AMORTIZATION	12	(4,089,420)	(2,642,542)	(738,590)	(36,437)	(210,155)	(460,551)	(1,145)
17	FLOW BACK OF EXCESS DEFERRED TAXES	12	(628,368)	(406,045)	(113,490)	(5,599)	(32,292)	(70,767)	(176)
18	EFFECT OF CNIT DEFERRED TAX ON FIT	12	(548,174)	(354,224)	(99,006)	(4,884)	(28,171)	(61,735)	(154)
19	FEDERAL INCOME TAX		5,239,012	5,519,124	580,691	(148,659)	509,527	(1,563,955)	342,284
20	STATE NET INCOME TAX (LINE 9)		(796,184)	162,135	(259,710)	(69,037)	35,283	(772,707)	107,853
21	TOTAL INCOME TAXES		4,442,828	5,681,259	320,981	(217,696)	544,810	(2,336,662)	450,137

COLUMBIA GAS OF PENNSYLVANIA, INC.
OCA ADJUSTED PEAK & AVERAGE
ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

<u>LINE NO.</u>	<u>DESCRIPTION</u> (A)	<u>ALLOC FACTOR</u> (B)	<u>TOTAL COMPANY</u> (C)	<u>RS/RDS</u> (D)	<u>SGS/SGDS</u> (E)	<u>LGS</u> (F)	<u>SDS</u> (G)	<u>LDS</u> (H)	<u>MDS</u> (I)
1	DESIGN DAY	1	781,900	476,000	181,700	9,300	41,700	73,200	0
2	PERCENT		100.000%	60.877%	23.238%	1.189%	5.333%	9.362%	0.000%
3	THROUGHPUT EXCLUDING TRANSPORTATION	2	32,319,197	23,112,788	8,213,924	931,484	0	0	61,000
4	PERCENT		100.000%	71.514%	25.415%	2.882%	0.000%	0.000%	0.189%
5	THROUGHPUT EXCLUDING MDS	3	71,872,223	32,785,788	13,343,450	931,484	7,023,159	17,788,342	0
6	PERCENT		100.000%	45.617%	18.566%	1.296%	9.772%	24.750%	0.000%
7	GAS PURCHASED EXPENSE	4	150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
8	PERCENT		100.000%	72.118%	25.034%	2.680%	0.000%	0.000%	0.168%
9	COMPOSITE ALLOCATORS 1 & 3	5							
10	PERCENT		100.000%	53.246%	20.902%	1.243%	7.553%	17.056%	0.000%
11	AVERAGE NO. OF CUSTOMERS	6	415,347	378,379	36,372	79	416	91	10
12	PERCENT		100.000%	91.099%	8.757%	0.019%	0.100%	0.022%	0.002%
13	CURRENT DIS REVENUE	7	345,846,630	273,183,950	72,662,680	-	-	-	-
14	PERCENT		100.000%	78.990%	21.010%	0.000%	0.000%	0.000%	0.000%
15	CURRENT GMB/GTS REVENUE	8	32,051,476	-	2,862,902	5,587,447	9,520,329	12,850,848	1,229,950
16	PERCENT		100.000%	0.000%	8.932%	17.433%	29.703%	40.094%	3.837%
17	DIRECT ASSIGNMENT - CUSTOMER DEPOSITS	9	1,962,296	1,502,111	460,185	-	-	-	-
18	PERCENT		100.000%	76.549%	23.451%	0.000%	0.000%	0.000%	0.000%
19	FORFEITED DISCOUNTS	10	751,992	610,142	124,726	753	7,695	7,653	1,024
20	PERCENT		100.000%	81.137%	16.586%	0.100%	1.023%	1.018%	0.136%
21	DIST. PLANT EXCL ACCTS 375.70, 375.71, & 387	11	1,425,838,257	921,049,664	256,929,411	12,646,755	73,579,383	161,239,159	393,885
22	PERCENT		100.000%	64.597%	18.020%	0.887%	5.160%	11.308%	0.028%
23	GROSS PLANT	12	1,477,108,215	954,468,062	266,787,613	13,167,082	75,914,543	166,356,599	414,315
24	PERCENT		100.000%	64.617%	18.061%	0.891%	5.139%	11.262%	0.028%

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

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	MAINS - ACCOUNT 376	13	911,044,198	484,978,841	190,381,019	11,321,577	68,794,749	155,350,620	217,392
2	PERCENT		100.000%	53.233%	20.897%	1.243%	7.551%	17.052%	0.024%
3	COMPOSITE DIRECT PLANT - ACCTS 376 & 380	14	1,285,044,803	826,960,502	221,479,780	11,594,570	69,213,587	155,541,341	255,022
4	PERCENT		100.000%	64.353%	17.235%	0.902%	5.386%	12.104%	0.020%
5	DIRECT ASSIGNMENT - SERVICES	15	262,823,185	240,345,517	21,856,197	191,151	295,258	135,062	-
6	PERCENT		100.000%	91.448%	8.316%	0.073%	0.112%	0.051%	0.000%
7	DIRECT ASSIGNMENT - METERS	16	24,235,911	18,173,549	5,739,937	66,820	196,940	55,413	3,252
8	PERCENT		100.000%	74.986%	23.684%	0.276%	0.813%	0.229%	0.013%
9	DIRECT ASSIGNMENT - IND M & R	17	6,712,184	-	4,490,787	397,657	1,309,527	514,212	-
10	PERCENT		100.000%	0.000%	66.905%	5.924%	19.510%	7.661%	0.000%
11	OTHER DISTRIBUTION O & M EXPENSES	18	33,374,478	21,569,153	6,579,998	286,995	1,596,588	3,335,811	5,933
12	PERCENT		100.000%	64.628%	19.716%	0.860%	4.784%	9.995%	0.018%
13	O & M EXCL GAS PUR, UNCOLLECTIBLES, & A & G	19	60,329,525	42,064,129	10,428,999	684,037	2,120,542	4,958,043	73,776
14	PERCENT		100.000%	69.724%	17.287%	1.134%	3.515%	8.218%	0.122%
15	MINIMUM SYSTEM MAINS	20							
16	PERCENT		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
17	LARGE CUSTOMER RELATIONS	21	157	-	18	41	-	88	10
18	PERCENT		100.00%	0.000%	11.465%	26.115%	0.000%	56.051%	6.369%
19	AVERAGE - ALLOCATORS 5 & 20	22							
20	PERCENT		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
21	UNBUNDLED UNCOLLECTIBLES	23	1,848,276	1,363,655	484,621	-	-	-	-
22	PERCENT		100.000%	73.780%	26.220%	0.000%	0.000%	0.000%	0.000%
23	LABOR	24	24,202,825	16,299,280	4,652,967	202,511	990,820	2,049,412	7,836
24	PERCENT		100.000%	67.345%	19.225%	0.837%	4.094%	8.468%	0.032%
25	SALES AND CHOICE TRANSPORTATION	25	47,121,722	32,785,788	13,343,450	931,484	-	-	61,000
26	PERCENT		100.000%	69.577%	28.317%	1.977%	0.000%	0.000%	0.129%

Value Line Natural Gas Utilities
Rates of Return on Common Equity
(2000-2011)

Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	All Years
AGL Resources	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	
Atmos Energy Corp.	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	
Laclede Group	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	
New Jersey Resources	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	
Northwest Natural Gas	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	
Piedmont Natural Gas	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	
South Jersey Industries	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	
Southwest Gas	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	
UGI Corp.	17.6%	22.5%	23.8%	17.6%	14.1%	18.2%	16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	
WGL Holdings	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	
AVERAGE	11.7%	12.2%	11.8%	12.1%	11.1%	12.0%	12.2%	11.4%	11.8%	12.1%	11.6%	10.4%	11.7%
STANDARD DEVIATION													0.54%

Source: Value Line Investment Survey, December 7, 2012.

**Columbia Gas of Pennsylvania
Residential Customer Cost Analysis**

	Per OCA CoC	Per Company CoC
Gross Plant		
Services	\$341,981,661	\$341,981,661
Meters	\$25,721,261	\$25,721,261
Automatic Meter Reading	\$15,407,948	\$15,407,948
Meter Installations	\$26,596,292	\$26,596,292
House Regulators	\$8,054,411	\$8,054,411
House Regulator Installations	\$2,897,999	\$2,897,999
Total Gross Plant	\$420,659,572	\$420,659,572
Depreciation Reserve		
Services	\$92,984,863	\$92,984,863
Meters	\$11,246,352	\$11,246,352
Automatic Meter Reading	\$3,329,755	\$3,329,755
Meter Installations	\$7,824,851	\$7,824,851
House Regulators	\$2,150,764	\$2,150,764
House Regulator Installations	\$2,091,048	\$2,091,048
Total Depreciation Reserve	\$119,627,633	\$119,627,633
Total Net Plant	\$301,031,939	\$301,031,939
Total Rate Base	\$301,031,939	\$301,031,939
Operation & Maintenance Expenses		
Oper Meter & House Reg.	\$1,841,440	\$1,841,440
Oper Customer Install Exp	\$3,609,095	\$3,609,095
Maint Services	\$2,751,104	\$2,751,104
Maint Meter & House Reg	\$214,505	\$214,505
Meter Reading	\$1,936,920	\$1,936,920
Billing and Accounting	\$5,281,623	\$5,281,623
Rendering Bills	\$2,263,580	\$2,263,580
Total O&M Expenses	\$17,898,267	\$17,898,267
Depreciation Expense		
Services	\$9,428,246	\$9,428,246
Meters	\$626,823	\$626,823
Automatic Meter Reading	\$1,333,428	\$1,333,428
Meter Installations	\$530,269	\$530,269
House Regulators	\$213,702	\$213,702
House Regulator Installations	\$54,338	\$54,338
Total Depreciation Expense	\$12,186,806	\$12,186,806
Revenue Requirement		
Interest	\$7,796,727	\$7,922,968
Equity Return	\$14,750,866	\$17,718,740
Income Tax	\$10,461,314	\$12,566,130
Total	\$33,008,907	\$38,207,838
Revenue For Return	\$33,008,907	\$38,207,838
O&M Expenses	\$17,898,267	\$17,898,267
Depreciation Expense	\$12,186,806	\$12,186,806
Total Customer Revenue Requirement	\$63,093,980	\$68,292,911
Number of Bills 1/	4,603,511	4,603,511
Monthly Cost	\$13.71	\$14.83

	Company Cost of Capital 2/		
	Pct	Cost	WGHT Cost
Debt 3/	47.68%	5.52%	2.63%
<u>Common</u>	<u>52.32%</u>	<u>11.25%</u>	<u>5.89%</u>
Total	100.00%		8.52%

	OCA Cost of Capital 3/		
	Pct	Cost	WGHT Cost
Debt 3/	48.42%	5.35%	2.59%
<u>Common</u>	<u>51.58%</u>	<u>9.50%</u>	<u>4.90%</u>
Total	100.00%		7.49%

1/ Per Company Revenue Proof at current rates.

2/ Per Exhibit 400, Schedule 1, Page 1.

3/ Per OCA Witness Kahal.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

REBUTTAL TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 28, 2013

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1 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

2 A. The purpose of this testimony is two-fold: first, I will make a minor correction to
3 the class cost of service study ("CCOSS") I sponsored in my direct testimony; and,
4 second, I will comment on the direct testimony of OSBA witness Robert Knecht as it
5 relates to class cost allocations, class revenue increase allocations, and Gas Procurement
6 Charges ("GPC").
7

8 **CORRECTION TO ORIGINAL CCOSS**
9

10 **Q. PLEASE PRESENT AND EXPLAIN THE CORRECTION TO THE CCOSS YOU**
11 **SPONSORED IN YOUR DIRECT TESTIMONY.**

12 A. In reviewing Mr. Knecht's revisions to the Company's CCOSS I discovered an
13 immaterial error in my CCOSS. This error relates to my attempted correction of a
14 mathematical modeling mistake admitted to by the Company as it pertains to the
15 allocation of storage plant (their allocation factor #25). Whereas the Company
16 inadvertently excluded rate SCD in this allocator, my attempt to correct this error also
17 resulted in a mistake in that I included rate SGDS (which should not be included).

18 The correction results in an immaterial change in class ROR's at current rates and
19 does not affect my revenue allocation recommendation. The following is a summary of
20 my "as-filed" and corrected class ROR's at current rates:

21

22 Class	As Filed	Corrected
23 RS/RDS	4.74%	4.71%
24 SGS/SGDS	3.69%	3.77%
25 LGS	0.37%	0.37%
26 SDS	5.06%	5.06%
27 LDS	0.55%	0.55%
28 MDS	285.00%	274%
29 Total Company	4.11%	4.11%

30
31

1 **CLASS COST OF SERVICE AND REVENUE ALLOCATIONS**

2
3 **Q. DOES OSBA WITNESS KNECHT SPONSOR ALTERNATIVE CCROSSs IN THIS**
4 **CASE?**

5 A. Yes. Mr. Knecht revised both of the CCROSSs proposed by Columbia in this case.
6 That is, he has revised the Company's Customer/Demand study in which Mains are
7 classified and allocated partially on the basis of number of customers and partially on the
8 basis of design day demand, as well as the Company's Peak and Average study in which
9 no consideration is given to customer counts within the allocation of Mains, but instead
10 reflect peak day (design day) and annual (average) usage. As will be discussed later in
11 this testimony, Mr. Knecht's second study utilizes a modified Average & Excess
12 ("A&E") method instead of the Peak & Average ("P&A") approach to allocate Mains
13 investment.
14

15 **Q. DO YOU HAVE ANY SIGNIFICANT AREAS OF AGREEMENT WITH MR.**
16 **KNECHT AS THEY RELATE TO HIS REVISIONS TO COLUMBIA'S CCROSSs?**

17 A. Yes. Mr. Knecht and I have both rejected the Company's proposed change in
18 methodology relating to the bifurcation of common (non-MDS) Mains between small/low
19 pressure and large/high pressure Mains. Instead, Mr. Knecht and I have allocated all
20 common use Mains on an aggregate basis. There are other issues in which I agree with
21 Mr. Knecht's revisions and criticisms of the Company's studies but the impacts of these
22 changes are relatively minor compared to the bifurcation of Mains issue. I will discuss
23 each of Mr. Knecht's revisions later in my testimony.
24

25 **Q. PLEASE COMMENT ON MR. KNECHT'S CUSTOMER/DEMAND ("C/D")**
26 **STUDY.**

27 A. By far, the biggest factor affecting class rates of return in natural gas LDC fully
28 allocated cost studies is the selection of, and use of, a particular methodology used to
29 ultimately allocate Mains investment. I have previously discussed my concerns and
30 criticisms of Columbia's Customer/Demand ("C/D") study in my direct testimony and
31 these same concerns and criticisms hold true for Mr. Knecht's C/D study. In addition,

1 Mr. Knecht has relied upon the “zero-intercept” approach to classify Mains within his
2 C/D study. Specifically, Mr. Knecht utilized the zero-intercept study results obtained by
3 Columbia’s CCOSS expert in the 2011 base rate case. This Commission has a long
4 standing practice of consistently rejecting any classification of natural gas LDC’s Mains
5 based on number of customers and has expressly rejected the zero-intercept approach.

6 For these reasons, I recommend the Commission give no weight or consideration
7 to either the Company’s or Mr. Knecht’s revised Customer/Demand CCOSSs.
8

9 **Q. PLEASE COMMENT ON MR. KNECHT’S SECOND CCOSS IN WHICH**
10 **THERE IS NO CUSTOMER COMPONENT OF MAINS INVESTMENT.**

11 A. Mr. Knecht modified the Company’s P&A class cost of service study by utilizing
12 an alternative method to allocate Mains investment and related costs. Specifically, Mr.
13 Knecht utilized a modified A&E approach to assign Mains related costs.
14

15 **Q. ARE THE P&A AND A&E METHODS DIFFERENT FROM A CONCEPTUAL**
16 **STANDPOINT?**

17 A. Yes. As correctly noted by Mr. Knecht, the P&A method assigns Mains related
18 costs based on two considerations: peak demand and average demand (annual usage).
19 The A&E method also consists of two components: average demand and excess demand.
20 This “Excess” demand is not the same as class relative contributions to peak demand but
21 rather, the difference (excess) between peak demand and average demand.¹

22 In the traditional A&E method, the “Average” and “Excess” components are
23 weighted based on system load factor, whereas the P&A method traditionally employed
24 in Pennsylvania weighs the Peak and Average components equally (50%/50%).² Mr.
25 Knecht deviated from the traditional A&E method by weighting the “Average” and
26 “Excess” portion of his Mains allocator equally (50%/50%).
27

¹ This excess demand reflects class differences in annual load factor such that a class with a perfect load factor would have an “excess demand of zero, while the excess demands for classes with imperfect load factors would be assigned excesses in relation to their respective load factors.

² The P&A method is also sometimes weighted based on system load factor.

1 Q. ALTHOUGH THERE ARE CONCEPTUAL DIFFERENCES BETWEEN THE
2 P&A AND TRADITIONAL A&E METHODS, DOES MR. KNECHT'S
3 MODIFIED A&E METHOD EFFECTIVELY ALLOCATE MAINS COSTS
4 CONSIDERING BOTH PEAK AND AVERAGE (ANNUAL) DEMANDS?

5 A. Yes. Mr. Knecht's modified A&E allocator results in a weighting of 65.68% peak
6 demand and 34.32% average demand.
7

8 Q. WHAT WEIGHTING BETWEEN PEAK AND AVERAGE DEMAND IS
9 EMBEDDED IN COLUMBIA'S AND YOUR P&A STUDIES?

10 A. Both Columbia's and my P&A studies utilize a 50% peak and 50% average
11 demand weighting.
12

13 Q. DOES MR. KNECHT'S MODIFIED A&E METHOD, WHICH EFFECTIVELY
14 UTILIZES A 65.68% PEAK AND 34.32% AVERAGE WEIGHTING, PRODUCE
15 SIGNIFICANTLY DIFFERENT RESULTS THAN THE P&A METHOD WHICH
16 WEIGHS THE PEAK AND AVERAGE COMPONENTS OF THE MAINS
17 ALLOCATORS EQUALLY (50%/50%)?

18 A. No. Mr. Knecht's modified A&E approach produces class rates of return at
19 current rates similar to those obtained under the P&A method. A comparison of Mr.
20 Knecht's A&E results and those obtained using the P&A method is provided below:

Class	ROR @ Current Rates	
	OSBA Modified A&E	OSBA Using P&A
RS/RDS	4.6%	4.8%
SGS/SGDS	4.1%	4.3%
LGS	3.5%	3.3%
SDS	3.6%	3.2%
LDS	0.8%	0.1%
MDS	273.7%	273.7%
Total Company	4.1%	4.1%

1 **Q. AS A POINT OF CLARIFICATION, WHY DO THE P&A RESULTS SHOWN**
2 **ABOVE NOT EQUAL THE P&A RESULTS OBTAINED UNDER YOUR P&A**
3 **STUDY?**

4 A. As discussed earlier, Mr. Knecht and I both rejected the Company proposed
5 bifurcation of common use Mains. However, Mr. Knecht made additional revisions to
6 Columbia's CCOSS that are not reflected in my study. As such, there are some
7 *differences in the two study results.*

8
9 **Q. PLEASE IDENTIFY MR. KNECHT'S OTHER CONCERNS AND**
10 **ADJUSTMENTS TO THE COMPANY'S CCOSS.**

11 A. First, it should be noted that while Mr. Knecht voiced concern over Columbia's
12 allocation of Meters and Services costs, he did not make an adjustment to the Company's
13 studies. That is, while Mr. Knecht identified various anomalies and/or unexpected results
14 obtained by Columbia, Mr. Knecht did not have the data available to make an alternative
15 recommendation. In this regard, I generally agree with Mr. Knecht's observations and
16 concerns such that these issues warrant further study (and potential refinement) in
17 *Columbia's next general base rate case.*

18 Mr. Knecht did make adjustments to Columbia's design day demands, industrial
19 metering and regulatory equipment, uncollectible expenses, storage gas, rental revenues,
20 and large customer relations expenses.

21
22 **Q. PLEASE EXPLAIN MR. KNECHT'S ADJUSTMENT TO DESIGN DAY**
23 **DEMANDS.**

24 A. Mr. Knecht conducted analyses of each individual large customer's (rate LGS,
25 SDS, LDS and MDS) maximum potential demand. He then summed his estimated
26 maximum demand by customer by rate schedule to evaluate the reasonableness of
27 Columbia's estimated design day levels for these classes. Based on these analyses, Mr.
28 Knecht determined that Columbia's estimated design day demand for the LGS class is
29 reasonable, but that the Company's estimates for the SDS and LDS classes are
30 understated.

1 While I do have concern as to whether Mr. Knecht's summation of individual
2 customer design day demands serves as a reasonable proxy of class design day demands,
3 I do believe his analyses supports a conclusion that Columbia's estimates of SDS and
4 LDS design day demands are at least somewhat understated.

5
6 **Q. PLEASE DISCUSS MR. KNECHT'S ADJUSTMENT TO INDUSTRIAL**
7 **METERING AND REGULATING EQUIPMENT.**

8 A. These costs are assigned only to the Commercial and Industrial classes. Mr.
9 Knecht's analysis concludes that the Small Volume Commercial/Industrial class may be
10 overallocated a share of these costs while the largest classes are underassigned costs.
11 Because this adjustment and impact on class ROR's is so small, I offer no opinion as to
12 Mr. Knecht's concerns and adjustment.

13
14 **Q. PLEASE COMMENT ON MR. KNECHT'S ADJUSTMENT TO**
15 **UNCOLLECTIBLE EXPENSE.**

16 A. As noted in Mr. Knecht's direct testimony, the Company separates its total
17 Uncollectible Expense (Account 904) into four categories: Universal Service Program
18 (\$8.47 million); unbundled Uncollectibles associated with gas costs (\$1.85 million);
19 small user rate schedule distribution Uncollectibles (\$3.04 million); and, large user rate
20 schedule distribution Uncollectibles (\$0.04 million).

21 Mr. Knecht accepted the Company's assignment of USP Uncollectibles entirely to
22 the Residential class but adjusted the allocation of bad debts expenses associated with
23 non-USP distribution and unbundled gas costs. In order to understand the impact of Mr.
24 Knecht's adjustment, the following is a comparison of the Company's and Mr. Knecht's
25 allocation of non-USP Uncollectible expense to the Residential class:

26

27	Uncollectible Expense	Knecht	Columbia
28	Distribution	85.6%	79.0%
29	Unbundled Purchased Gas	86.2%	73.8%

30
31

1 With regard to Mr. Knecht's adjustment to distribution (base rates) Uncollectible
2 expense, I believe his analysis of charge-off rates by class has merit and is reasonable.
3 With regard to this adjustment to unbundled purchased gas Uncollectibles, I disagree
4 with Mr. Knecht's adjustment. The Commission has already unbundled Uncollectible
5 expenses associated with purchased gas costs such that there is a separate (non-
6 distribution) Merchant Function Charge ("MFC") applicable to sales only customers for
7 this expense. This MFC revenue is included in both the Company's and Mr. Knecht's
8 CCOSS. Notwithstanding whether an adjustment to an unbundled expense that is
9 recovered through a separate mechanism (outside of a distribution general rate case) is
10 appropriate or not, Mr. Knecht erred by re-allocating the unbundled expenses without re-
11 allocating the unbundled revenue associated with this expense. In other words, Mr.
12 Knecht allocated more costs to the Residential class associated with the MFC, but he did
13 not make a corresponding adjustment to Residential MFC revenues.

14
15 **Q. PLEASE COMMENT BRIEFLY ON MR. KNECHT'S ALLOCATION**
16 **ADJUSTMENTS TO STORAGE GAS, RENTAL REVENUES AND LARGE**
17 **CUSTOMER RELATIONS EXPENSES.**

18 **A.** Mr. Knecht's allocation adjustments to these costs have very minor impacts on
19 class ROR's (individually or collectively). This being said, his adjustments are
20 reasonable and appropriate.

21
22 **Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. KNECHT'S**
23 **ALTERNATIVE A&E CLASS COST OF SERVICE STUDY?**

24 **A.** While I do not agree in concept with all of the opinions of Mr. Knecht, I am a
25 firm believer of the end-result doctrine. As such, I see no need to burden this record or
26 the Commission with academic differences of opinion. When it is all said and done, Mr.
27 Knecht's alternative approach produces results that are very similar to my P&A CCOSS.

28
29 **Q. DID MR. KNECHT RELY PRIMARILY ON COST OF SERVICE RESULTS IN**
30 **DEVELOPING CLASS REVENUE ALLOCATION PROPOSALS?**

1 A. Yes. Mr. Knecht offers two separate class revenue allocation proposals: one
2 based on his C/D CCOSS and another based on his A&E CCOSS.

3
4 **Q. HOW DO MR. KNECHT'S PROPOSED CLASS REVENUE ALLOCATIONS**
5 **COMPARE TO YOUR RECOMMENDATION?**

6 A. Mr. Knecht's and my proposed class revenue allocations are also very similar in
7 this case. To illustrate, the following is a comparison of Columbia's, Mr. Knecht's and
8 my class revenue increases at the Company's requested overall increase of \$77.3 million:

9
10 Increase @ \$77.3 Million
(\$Million)

11 Class	12 Columbia	OCA	OSBA A&E Option	OSBA C/D Option
13 RS/RDS	\$61,779	\$55,508	\$49,913	\$58,939
14 SGS/SGDS	\$14,357	\$12,619	\$15,272	\$13,811
15 LGS	\$582	\$802	\$791	\$565
16 SDS	\$582	\$2,444	\$4,824	\$2,193
17 LDS	\$11	\$5,939	\$6,510	\$1,802
18 MDS	\$0	\$0	\$1	\$1
19 Total Company	\$77,311	\$77,311	\$77,311	\$77,311

20 As can be seen above, Mr. Knecht's and my proposed class revenue allocations are
21 largely similar when compared to Columbia's revenue allocation proposal. That is, while
22 there are some absolute differences in the assignment of increases to the Residential
23 (RS/RDS) and Small General Service (SGS/SGDS) classes, Mr. Knecht and I both
24 recommend significantly larger increases to the SDS and LDS classes than does
25 Columbia.

1 **GAS PROCUREMENT CHARGE (“GPC”)**

2
3 **Q. PLEASE COMMENT ON OSBA WITNESS KNECHT’S AND NATURAL GAS**
4 **SUPPLIERS (“NGS”) WITNESS CRIST’S ADJUSTMENTS TO COLUMBIA’S**
5 **PROPOSED GAS PROCUREMENT CHARGE AS THEY RELATE TO GAS**
6 **STORAGE WORKING CAPITAL.**

7 A. In order to explain the various options and proposals concerning a working capital
8 requirement associated with Columbia-owned storage gas, it is important to understand
9 how Columbia incurs these financing costs as well as understand which customers utilize
10 and benefit from Columbia-owned storage gas. Columbia-owned storage gas is used to
11 meet the winter needs of Sales & Choice customers, with only minimal use by “normal”
12 transportation customers (i.e. is used for some balancing). As is the case for virtually all
13 natural gas LDCs, Columbia begins injecting gas into storage in the late spring to early
14 summer and continues to build inventory through the autumn into the true heating season.
15 During the winter months, Columbia then withdraws Company-owned storage gas to
16 meet the higher winter demands and usages of its Sales & Choice customers. Although
17 Choice NGSs inject their own gas into Columbia’s system, the Choice Program tariff
18 rules are such that Choice NGSs are only required to inject gas daily on an average daily
19 basis.³ Although Choice NGSs daily injections of gas are greater than their retail
20 customers’ usage requirements in the late summer to early fall (thereby creating a
21 surplus), the Choice daily delivery requirements result in a Choice shortfall later in the
22 heating season, thereby requiring Choice NGSs to effectively “borrow” against
23 Columbia’s-owned storage gas. As such, Columbia incurs financing costs associated
24 with its Company-owned storage gas for both Sales & Choice customers.

25
26 **Q. HOW DOES COLUMBIA REFLECT THE COST INCIDENCE OF STORAGE**
27 **WORKING CAPITAL COSTS?**

28 A. Columbia does not unbundle storage working capital costs within its proposed
29 GPC. Rather, the Company retains these working capital costs within its base rate
30 revenue requirement and allocates these costs only to Sales and Choice customers; i.e.

³ Tariff Rule 4.9.3, page 238.

1 regular (non-Choice) transportation customers are not assigned any costs associated with
2 storage working capital. As a result, the Company's proposed GPC does not reflect
3 storage working capital and is also only charged to Sales customers (will not apply to
4 Choice or regular transportation customers).
5

6 **Q. HOW DO MR. KNECHT'S AND MR. CRIST'S RECOMMENDATIONS DIFFER**
7 **FROM COLUMBIA'S PROPOSED COST ASSIGNMENT AND COLLECTION**
8 **OF STORAGE WORKING CAPITAL COSTS?**

9 A. Both Mr. Crist and Mr. Knecht recommend that storage gas working capital costs
10 should be unbundled from base rates. However, their proposed recovery of these
11 financing costs differ. Whereas Mr. Crist recommends that these costs be unbundled
12 from base rates and collected only from Sales customers, Mr. Knecht recognizes that
13 these costs are incurred for and benefit both Sales customers and Choice NGSs.
14

15 **Q. IS MR. CRIST'S UNBUNDLING RECOMMENDATION OF STORAGE GAS**
16 **WORKING CAPITAL COSTS REASONABLE OR APPROPRIATE?**

17 A. No. It is clear that Columbia incurs storage gas working capital costs on behalf of
18 both its Sales customers as well as Choice NGSs. Mr. Crist's approach would unbundle
19 storage gas working capital and collect all of these costs only from Sales customers
20 within the GPC.
21

22 **Q. PLEASE EXPLAIN MR. KNECHT'S RECOMMENDED APPROACH TO**
23 **COLLECT STORAGE GAS WORKING CAPITAL COSTS.**

24 A. Mr. Knecht also proposes to unbundle storage gas working capital costs from base
25 rates, but unlike Mr. Crist, recognizes that these costs are incurred for both Sales
26 customers and Choice NGSs. In this regard, Mr. Knecht offers two options. Under both
27 options, Mr. Knecht would unbundle storage gas working capital costs and allocate these
28 costs between Sales customers and Choice NGSs. With this framework, Choice NGSs
29 would have the option of either: (a) paying a charge to Columbia relating to the
30 financing costs associated with storage gas; or, (b) modify its daily delivery requirements

1 such that the NGS would be required to increase their daily injections during the non-
2 heating season.

3
4 **Q. DO YOU AGREE WITH MR. KNECHT'S RECOMMENDED APPROACH?**

5 A. While Mr. Knecht's options are technically correct, and indeed may be workable,
6 they are complicated and open for significant controversy. That is, if Mr. Knecht's
7 approach were adopted, Columbia's total storage gas working capital costs must first be
8 unbundled from base rates and then allocated between Sales customers and Choice NGSs
9 (which will almost certainly lead to additional controversy). Because Choice NGSs'
10 utilization of Columbia's storage gas working capital would vary depending on whether
11 Mr. Knecht's Option (a) or Option (b) is selected, a rather complicated set of daily or
12 monthly Choice NGS working capital charges would then have to be developed.⁴

13
14 **Q. IS THERE A SIMPLER, YET JUST AS EFFECITVE, SOLUTION TO THE**
15 **STORAGE GAS WORKING CAPITAL DILEMMA?**

16 A. Yes. A much simpler, fair, and effective approach is that proposed by Columbia.
17 That is, Columbia's proposed recovery of these costs is fair to all stakeholders in that: (a)
18 the Company assigns cost responsibility for these working capital costs only to Sales and
19 Choice customers within its class cost of service studies and retains the recovery of these
20 costs within base rates;⁵ (b) the Company is afforded an opportunity to recover a
21 reasonable level of these financing costs; (c) there is no additional controversy
22 surrounding the collection of these costs between Sales customers and Choice NGSs;
23 and, (d) there is no additional administrative or regulatory burden created from the
24 development of complicated storage gas working capital charges.

25
26

⁴ Furthermore, if Choice NGSs were to select Mr. Knecht's option to modify their daily delivery requirements, there is no guarantee that a given Choice NGS will over or under contribute to Columbia's storage working capital costs unless such charges were trued-up or assessed after the heating season.

⁵ In this way, regular (non-Choice) transportation customers are not burdened with storage gas working capital costs.

1 **Q. IF THE COMMISSION DISAGREES WITH COLUMBIA'S APPROACH AND**
2 **REQUIRES THE UNBUNDLING OF STORAGE GAS WORKING CAPITAL**
3 **COSTS, SHOULD ANY OF THESE COSTS BE ASSESSED DIRECTLY TO**
4 **CHOICE RETAIL CUSTOMERS?**

5 A. The costs should be assessed directly to NGSs, not to the Choice customers. The
6 spirit and intent of the Choice program is to enhance competition for the supply of natural
7 gas. That is, while the costs incurred by NGSs may or may not vary, cost responsibility
8 is left with the NGSs such that they are free to charge what the market will bear.
9 Columbia's storage working capital costs associated with the Choice program are clearly
10 incurred as a result of individual NGS supplies and withdrawals from Columbia's storage
11 facilities and indeed will vary from NGS to NGS. For this reason, it would not be
12 appropriate to directly charge retail Choice customers for these costs. In other words,
13 Choice NGSs should be responsible for this cost they impose on Columbia, which then
14 will be included along with all other factors in determining the competitive price of
15 Choice gas.

16
17 **Q. IF STORAGE GAS WORKING CAPITAL COSTS ARE UNBUNDLED FROM**
18 **BASE RATES, WHAT COST RATE SHOULD BE ASCRIBED TO THESE**
19 **FINANCING COSTS?**

20 A. Because natural gas LDCs finance storage gas working capital with short-term
21 debt, any unbundling of these costs should be calculated using Columbia's cost of short-
22 term debt.

23
24 **Q. IF STORAGE GAS WORKING CAPITAL COSTS ARE UNBUNDLED FROM**
25 **BASE RATES, ARE THERE TOTAL REVENUE REQUIREMENT**
26 **IMPLICATIONS ASSOCIATED WITH THESE COSTS?**

27 A. Yes. The Company's application reflects all storage working capital costs. To
28 the extent they are unbundled these costs need to be deducted from Columbia's base
29 distribution revenue requirement.

30 **Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?**

31 A. Yes.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

SURREBUTTAL TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

FEBRUARY 8, 2013

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2-13-13
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1 **Q. PLEASE STATE YOUR NAME.**

2 A. My name is Glenn A. Watkins.

3
4 **Q. HAVE YOU PREVIOUSLY PRE-FILED TESTIMONY IN THIS CASE?**

5 A. Yes. I pre-filed direct testimony on January 4, 2013 and pre-filed rebuttal
6 testimony on January 28, 2013.

7
8 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

9 A. The purpose of this testimony is to respond briefly on class cost of service
10 ("CCOSS") issues raised by Columbia Industrial Intervenors witness Richard Baudino
11 and OSBA witness Robert Knecht. In addition, I will respond to various comments of
12 Columbia witness Paula Strauss regarding the Company's Residential rate design
13 proposals relating to its Revenue Normalization Adjustment ("RNA") and Weather
14 Normalization Adjustment ("WNA") options. Finally, I respond briefly to the rebuttal
15 testimony of Columbia witness Erich Evans relating to the Company's proposed pilot
16 NAS rider. It should be noted however, that my silence on other issues raised in the
17 rebuttal testimonies of the witnesses in this case does not constitute any agreement with
18 their rebuttal, but rather the foundation and reasons for my opinions are set forth and fully
19 developed in my direct testimony.

20
21 **Q. PLEASE RESPOND TO MESSRS. BAUDINO AND KNECHT AS IT RELATES**
22 **TO THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION MAINS**
23 **WITHIN A CCOSS.**

24 A. The philosophical issue of how natural gas distribution Mains should ultimately
25 be allocated to customer classes has been debated before this Commission for decades.
26 That is, while some experts such as Messrs. Baudino and Knecht are of the opinion that
27 distribution Mains should be allocated partially based on number of customers and
28 partially based on maximum theoretical potential demand (design day demand), other
29 experts such as myself, are of the opinion that distribution Mains are more appropriately
30 allocated to customer classes based partially on usage throughout the year (throughput or
31 annual demand) and partially on peak demand. This Commission has for years

consistently found that the allocation of natural gas distribution Mains should not consider or reflect number of customers and that Mains should be allocated considering both annual and peak demand. There is no doubt that the existence of a LDC system is predicated upon customer's usage throughout the year. That is, it would be economically unfeasible to build and operate a natural gas distribution system if consumers were to utilize the LDC facilities on only the theoretically coldest day possible, which may only occur once every twenty or so years. Furthermore, consumers do not become customers simply for the luxury of being connected to the LDC system, but rather, become customers to meet their natural gas energy needs throughout the year. As is explained in my direct testimony, while it is true that Columbia's Mains are in place to serve the energy needs of its customers throughout the year, the utilization of Mains varies over the course of a year. As such, cost allocation methodologies that consider both annual and peak day demands strike a reasonable balance pertaining to the assignment of Mains investment and related costs. This consideration of both average (annual) and peak demands has been consistently found to be appropriate in countless natural gas LDC cases by this Commission. In addition, this Commission has consistently rejected proposals and methodologies that allocate Mains which consider number of customers and/or only maximum potential peak day demand.

Q. PLEASE COMMENT ON MS. STRAUSS' REBUTTAL TESTIMONY CONCERNING THE COMPANY'S PROPOSED RESIDENTIAL RNA AND WNA.

A. By and large, Ms. Strauss attempts to defend the Company's preferred option to implement a RNA or in the alternative, implement a WNA. However, Ms. Strauss does not address the fundamental flaws embedded within these guaranteed revenue recovery mechanisms. That is, the Company's proposals are totally one-sided in that they provide considerable benefits to shareholders by reducing risk and guaranteeing revenue with no benefits to captive Residential ratepayers or recognition of the reduced risk confronted by the Company. As explained in detail in my direct testimony, the Company's RNA and WNA proposals are at odds with accepted economic theory as well as the pricing policies of academicians and regulators for well over a century. While the majority of states have

1 maintained traditional Residential pricing policies and rate designs, it is true that some
2 state regulatory commissions or state legislatures have adopted guaranteed revenue
3 recovery mechanisms (also referred to as revenue decoupling). My experience across the
4 Country indicates that these states have recognized the balancing of interests between
5 shareholders and ratepayers and required that such revenue decoupling mechanisms be
6 tied to defined and effective conservation plans implemented by the utilities which will
7 materially and efficiently reduce Residential natural gas consumption and/or specific
8 recognition of the reduced risks confronted by shareholders with an attendant reduction to
9 the authorized rate of return on equity.

10
11 **Q. IF THE COMMISSION DISAGREES WITH YOUR RECOMMENDATION TO**
12 **MAINTAIN A TRADITIONAL RESIDENTIAL RATE DESIGN AND ALLOWS**
13 **SOME FORM OF GUARANTEED REVENUE RECOVERY, SHOULD THE**
14 **COMMISSION EXPLICITLY RECOGNIZE THE REDUCED RISKS THAT**
15 **WILL CONFRONT COLUMBIA SHAREHOLDERS?**

16 A. Yes. If the Commission authorizes any form of guaranteed revenue recovery
17 from Residential customers, the Company's overall authorized rate of return on equity
18 should be reduced for revenue requirement purposes, and since this reduced risk would
19 be totally associated with the Residential class, the base rate increase authorized for the
20 Residential class should be lower than that recommended in my direct testimony.

21
22 **Q. IF THE COMMISSION ADOPTS SOME FORM OF REVENUE DECOUPLING,**
23 **IS A RNA OR WNA A BETTER APPROACH?**

24 A. Should the Commission authorize some form of guaranteed revenue recovery for
25 the Residential class, a WNA mechanism is much preferred over the Company's RNA
26 mechanism. If a WNA is adopted, however, the Company's mechanism should be
27 modified to reflect only exceptional abnormalities or variations in weather. As indicated
28 in my direct testimony, it is unrealistic and improper to so narrowly assume that weather
29 (and attendant natural gas usage) is abnormal if a particular day is only a few degrees
30 warmer or colder than some predefined twenty or thirty year average. The Company's
31 WNA, as designed, would institute a revenue adjustment if the actual weather pattern was

1 only one heating degree day colder or warmer than a predefined average. While
2 Columbia's WNA mechanism as designed is better than some other WNAs I have seen in
3 that price changes would be reflected in the same month that weather varies from normal
4 (as opposed to a lagged billing approach), a deadbanding percentage should be
5 incorporated into the WNA mechanism if a WNA is approved. This deadbanding
6 concept allows for the adjustment to revenues under truly abnormal weather conditions
7 yet recognizes that some variation can and will occur on a day to day or monthly basis.
8 As such, a deadbanding concept will adjust revenues upward or downward only beyond a
9 predefined threshold. For example, if the weather in a particular winter month is only
10 slightly higher or lower than average, a WNA would not be triggered. On the other hand,
11 if weather were truly abnormally cold or warm, the WNA would be implemented upward
12 or downward to the predefined deadband percentage above or below normal weather.

13
14 **Q. WHAT IS A REASONABLE DEADBAND PERCENTAGE IF THE**
15 **COMMISSION ADOPTS A WNA APPROACH?**

16 A. In my opinion, a WNA should have a minimum deadband percentage of 20%. In
17 this way, the Company would still recover the vast majority of any revenue shortfall
18 associated with truly abnormal warm weather, or credit customers' bills under
19 circumstances of truly abnormal cold weather. At the same time, a deadband of 20%
20 would not adjust customers' bills due to minor fluctuations in weather.

21
22 **Q. DO YOU HAVE ANY COMMENTS REGARDING THE REBUTTAL**
23 **TESTIMONY OF COLUMBIA WITNESS ERICH EVANS AS IT RELATED TO**
24 **THE COMPANY'S PROPOSED PILOT NAS RIDER?**

25 A. While Mr. Evans acknowledges various concerns and shortcomings of the
26 Company's proposed NAS rider raised by I&E and myself and expresses a willingness to
27 work with stakeholders in resolving these issues, he opposes my recommendation to
28 defer implementation of such a pilot rider. In my opinion, it is much preferred to delay
29 the implementation of a new tariff provision in order to design such a rider that is fully
30 thought out, is structured properly, and is fair to all stakeholders rather than approve a
31 rate with known problems and then attempt to correct problems at a later date.

1 Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

2 A. Yes.

3 165799

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

v.

COLUMBIA GAS COMPANY OF
PENNSYLVANIA

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Docket Nos. R-2012-2321748
M-2012-2323645

REBUTTAL TESTIMONY OF
ROGER D. COLTON

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA STATEMENT 4-R

January 28, 2013

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1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Roger Colton. My business address is 34 Warwick Road, Belmont, MA
3 02478.

4
5 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?**

6 A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General
7 Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to
8 a variety of federal and state agencies, consumer organizations and public utilities on rate
9 and customer service issues involving telephone, water/sewer, natural gas and electric
10 utilities.

11
12 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?**

13 A. I am testifying on behalf of the Office of Consumer Advocate (“OCA”).

14
15 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.**

16 A. I work primarily on low-income utility issues. This involves regulatory work on rate and
17 customer service issues, as well as research into low-income usage, payment patterns,
18 and affordability programs. At present, I am working on various projects in the states of
19 New Jersey, Maryland, Pennsylvania, Virginia, Minnesota and Hawaii. My clients
20 include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland
21 Office of People’s Counsel, Iowa Department of Human Rights), federal agencies (e.g.,
22 the U.S. Department of Health and Human Services), community-based organizations
23 (e.g., Energy Outreach Colorado, Community Action Partnership Association of Idaho),

1 and private utilities (e.g., Unitil Corporation d/b/a Fitchburg Gas and Electric Company,
2 Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state-
3 and utility-specific work, I engage in national work throughout the United States. For
4 example, in 2011, I worked with the U.S. Department of Health and Human Services (the
5 federal LIHEAP office) to advance the review and utilization of the Home Energy
6 Insecurity Scale as an outcomes measurement tool for LIHEAP. In 2010, I completed (as
7 one member of a team) work on a national study of the responses of water utilities to the
8 payment troubles of residential customers for the U.S. Environmental Protection Agency
9 and the American Water Works Association Research Foundation. In 2007, I was part of
10 a team that performed a multi-sponsor public/private national study of low-income
11 energy assistance programs. A brief description of my professional background is
12 provided in Appendix A.

13
14 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

15 A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained
16 further training in both law and economics. I received my law degree in 1981 (University
17 of Florida). I received my Master's Degree (economics) from the MacGregor School in
18 1993.

19
20 **Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY**
21 **ISSUES?**

22 A. Yes. I have published more than 80 articles in scholarly and trade journals, primarily on
23 low-income utility and housing issues. I have published an equal number of technical

1 reports for various clients on energy, water, telecommunications and other associated
2 low-income utility issues.

3
4 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY**
5 **COMMISSIONS?**

6 A. Yes. I have testified before the Pennsylvania Public Utility Commission (“PUC” or
7 “Commission”) on numerous occasions regarding utility issues affecting low-income
8 customers. I have also testified in regulatory proceedings in more than 30 states and
9 various Canadian provinces on a wide range of low-income utility issues.

10
11 **Q. PLEASE EXPLAIN THE PURPOSE OF YOUR REBUTTAL TESTIMONY.**

12 A. The purpose of my Rebuttal Testimony is to respond to certain aspects of the Direct
13 Testimony filed in this proceeding by the following witnesses: (1) I&E witness Rachel
14 Maurer; (2) I&E witness Daniel Mumford; and (3) CAUSE-PA witness Eugene Brady.

15
16 **Part 1. Rebuttal to I&E Witness Rachel Maurer.**

17 **Q. PLEASE EXPLAIN THE ISSUE ADDRESSED BY I&E WITNESS MAURER TO**
18 **WHICH YOU WISH TO RESPOND.**

19 A. I&E witness Rachel Maurer recommends that even if Columbia Gas is granted its request
20 to make changes to the Warm Wise Audits & Rebates program (“Warm Wise A&R”)
21 without seeking Commission approval, “Columbia should not be permitted to change [its]
22 customer eligibility qualification of having an income between 151% and 250% of the
23 Federal Poverty Guideline.” (I&E Statement 4, at 8).

1
2 I endorse that recommendation. Columbia witness Kempic states that the Company seeks
3 permission to be able "to make changes and enhancements to the WarmWise-A&R
4 program design and implementation without seeking Commission approval for each
5 individual change provided that the program costs do not exceed its currently approved
6 annual funding level of \$750,000. In other words, Columbia would like the approval to
7 manage the program within the authorized budget without continually seeking approval
8 of each individual change. (CGPA Statement No. 1, at 36, 38). Mr. Kempic's request is
9 reasonable, given his observation that "Based on experience with other programs,
10 understanding customer needs, and in light of the changing marketplace for energy
11 efficiency products and services, Columbia may find it appropriate to modify the upfront
12 rebate levels and[/]or the qualifying measures in order to maximize the impact of the
13 WarmWise-A&R program." (CGPA Statement 1, at 38). CGPA should be permitted to
14 make change such as modifications to the upfront rebate levels and/or the qualifying
15 measures in order to maximize the effectiveness of the program.
16

17 **Q. IS THERE ANY CHANGE COLUMBIA SHOULD NOT BE PERMITTED TO**
18 **MAKE?**

19 A. Yes. I agree with I&E witness Maurer that "Columbia should not be permitted to change
20 [its] customer eligibility qualification of having an income between 151% and 250% of
21 the Federal Poverty Guideline." As with the corresponding LIURP energy usage
22 reduction program, the reason that the WarmWise-A&R program exists is because, in its
23 absence, cost-effective usage reduction might be left on the table in limited-income

1 homes because of the very fact of their limited-income status. There is reason to believe
2 that the income status of households is important for purposes of a use reduction program
3 in that it stands, in large part, as a surrogate for barriers that are unique to the poor (and
4 near-poor) that would prevent the household from being able to implement usage
5 reduction strategies in the absence of a program such as WarmWise-A&R. Programs
6 such as LIURP and the WarmWise-A&R are directed toward overcoming market barriers
7 that prevent such households from implementing usage reduction measures on their own.
8 Such market barriers would include, for example, the lack of investment capital and the high
9 "hurdle rates" implicit in energy efficiency investment decisions. Accordingly, while CGPA
10 may be allowed to manage the details of its program within its proposed budget limits
11 without additional Commission approval, a modification of the income eligibility guidelines
12 should not fall within that management discretion.

13
14 I conclude that the recommendation of I&E witness Maurer that Columbia should not be
15 allowed to change the customer eligibility qualification for WarmWise-A&R is well-
16 founded and should be adopted.

17
18 **Q. IS THERE A SECOND RECOMMENDATION OF I&E WITNESS MAURER**
19 **THAT YOU WISH TO ADDRESS?**

20 **A.** Yes. I&E witness Maurer recommends that the funding level for the WarmWise A&R
21 program be reduced to \$200,000 per year. (I&E Statement 4, at 8). She bases this
22 recommendation on her observation that "Columbia has spent an average of \$160,800
23 annually over the prior three years." (I&E Statement 4, at 9). While witness Maurer

1 acknowledges that, due to the reconcilable nature of the Company's universal service rate
2 rider, ratepayers do not pay for any budgeted dollars that are not actually spent, she
3 asserts that "it is unreasonable to repeatedly artificially inflate the budget in view of the
4 historical expense." (I&E Statement 4, at 9).

5
6 I do not agree with Ms. Maurer that the historical expense provides an accurate measure
7 of the potential for this program. Ms. Maurer's recommendation fails to account for the
8 substantial influx of ARRA¹ funds to local weatherization agencies in 2009. Under
9 ARRA, Pennsylvania received \$252,793,062 in funds to be devoted to weatherization
10 over a three-year period. Pennsylvania was charged with weatherizing more than 29,500
11 homes over that three-year period. By March 2011 (i.e., end of "Year 2"), Pennsylvania
12 had weatherized 16,064 homes using ARRA funds.²

13
14 The delivery of weatherization services is a specialized activity requiring trained staff.
15 Merely providing dollars for weatherization does not immediately create the capacity to
16 deliver those services. Given an influx of more than \$250 million in weatherization
17 funding in 2009, Pennsylvania's weatherization providers were charged with developing
18 the institutional capacity to deliver, on-the-ground, those services that were funded
19 through ARRA.³ During the three-year period of the ARRA funding, the Pennsylvania
20 weatherization community accomplished that ramp-up. By the end of Year 2, the

¹ American Recovery and Reinvestment Act of 2009.

² National Association for State Community Service Programs, "Weatherization Assistance Program: Funding Survey: PY2011," at Table 8.

³ ARRA funding provided funding for WAP-defined weatherization services. The weatherization was for all fuels, but was limited to those measures that would otherwise have been supported by the federal WAP program.

1 weatherization community had weatherized more than 16,000 homes that, prior to 2009,
2 it would have had neither the funding nor the capacity to reach.

3
4 In light of the ARRA funding, however, it should not be surprising that the production
5 under the Company's WarmWise-A&R program lagged. However, ARRA funding has
6 now lapsed (ARRA provided a fixed sum of weatherization dollars to be used by a
7 prescribed deadline, which is now past). The institutional capacity developed through
8 ARRA is now at risk. Indeed, according to the most recent annual funding survey of the
9 National Association of State Community Service Programs (NASCSPP), the national
10 association of weatherization provider-agencies, "The WAP community recognizes that,
11 due to funding levels, maintenance of the Recovery Act level of production will likely be
12 impossible. In fact, some Grantees and sub-grantees have already been forced to lay off
13 workers and shrink their operations." (NASCSPP Annual Weatherization Funding Survey:
14 2011, at 5).

15
16 I conclude that use of expenditure levels during the three-year period in which
17 Pennsylvania weatherization providers were charged with reaching 29,554 low-income
18 units, with one-time, time-constrained, funding is not a sound basis to now reduce the
19 funding for WarmWise A&R funding into the future. Given the ramp-up in institutional
20 capacity to deliver services, now is the time for Columbia Gas to maintain or increase its
21 funding to ensure that the "new" capacity that was enabled by ARRA is not permanently
22 lost, along with the lost benefits generated for the Company and its remaining ratepayers.

Part 2. Rebuttal to I&E Witness Daniel Mumford.

Q. PLEASE EXPLAIN THE ISSUE ADDRESSED BY I&E WITNESS MUMFORD TO WHICH YOU WISH TO RESPOND.

A. In I&E Statement No. 6, witness Mumford expressed concerns “over Columbia’s practices with respect to how it handles arrears under its CAP and POR programs, or arrears that are older than four years.” (I&E Statement 6, at 17).⁴ Mr. Mumford urges that “[t]he practice of transferring account balances, including POR balances, for which the Company is no longer able to terminate service, into the accounts of current CAP customers, then forgiving the arrearages, is inappropriate.” (I&E Statement 6, at 22). Mr. Mumford states that “[t]he only entity that this practice appears to benefit is the utility. Columbia gets to fully recover outdated pre existing arrearages under a Universal Service Program Rider that were previously only possibly recoverable via conventional recovery mechanisms, i.e. uncollectible expense, if at all.” (I&E Statement 6, at 23).

I&E witness Mumford has identified a legitimate concern with respect to the Company’s practices. The practice of transferring account balances, for which the Company is no longer able to terminate service, into the accounts of current CAP customers, then forgiving the arrearages, is contrary to the purpose and structure of the CAP program, the arrearage forgiveness component of the CAP program, and the CAP cost recovery mechanism. I agree with Mr. Mumford for three reasons:

⁴ “CAP” refers to the Company’s Customer Assistance Program. “POR” refers to the Company’s Purchase of Receivables program.

1 First, the purpose of CAP is to provide a cost-effective response to inability-to-pay. The
2 Commission's 1999 Order stated in relevant part that "an appropriately designed and
3 well-implemented CAP, as an integrated part of a company's rate structure, is in the
4 public interest. Further, the results show that CAPs can be a more cost effective approach
5 for dealing with issues of customer inability to pay than traditional collection methods."
6 That 1999 Order stated further that: "The Commission is amending the scope of CAPs
7 based on ... [the fact that] evaluations show that CAPs are a cost-effective alternative to
8 traditional collection policies." Re Revisions to the Customer Assistance Program Policy
9 Statement Made Pursuant to 52 Pa. Code Chapter 69, Docket No. M-00991232 (April 9,
10 1999). Clearly, if a customer arrearage is, for whatever reason, not subject to collection,
11 including that arrearage in the CAP cannot be "a more cost-effective approach. . .than
12 traditional collection methods." Moreover, if a customer arrearage is, for whatever
13 reason, not subject to collection, including that arrearage in CAP cannot be "a cost-
14 effective alternative to traditional collection policies."
15

16 Second, including an arrearage not now subject to collection in the CAP (through
17 "arrearage forgiveness") is not consistent with the Commission's explanation of how
18 CAP interacts with a utility's collection process. According to the Commission, "Failure
19 to make payments will result in the utility returning the participant to the regular
20 collection cycle and may lead to termination of service. By returning the customer to the
21 regular collection cycle, the utility does not need to enter into a new payment
22 arrangement but may begin the termination process. At a minimum, the utility should
23 inform the participant of the consequences of defaulting from the CAP." 1999 CAP

1 Revisions, Section 69.265 (emphasis added). Clearly, the Commission’s reference to a
2 “return” of the customer to the “regular collection cycle” indicates the Commission’s
3 intention that customer bills subject to the CAP program provisions would otherwise be
4 subject to the “regular collection cycle.” If there exists no collection cycle to which the
5 customer would be “returned” in the event of CAP nonpayment of a pre-existing
6 arrearage, that pre-existing arrearage should not be a part of the CAP program.

7
8 Third, the Pennsylvania legislature has specifically defined “universal service” for natural
9 gas companies. (66 C.S. §2202). Under that definition, “universal service” includes
10 “policies, practices and services that help residential low-income retail gas customers and
11 other residential retail gas customers experiencing temporary emergencies, as defined by
12 the commission, to maintain natural gas supply and distribution services.” (emphasis
13 added). If, for whatever reason, a pre-existing arrearage is not subject to collection from
14 a customer, making that pre-existing arrearage subject to arrearage forgiveness under the
15 Company’s CAP does not help the customer “to maintain natural gas supply and
16 distribution service.” Accordingly, such an arrearage, when it is not subject to collection,
17 does not fall within the statutory definition of a “universal service” program.

18
19 In sum, I support the recommendation of Mr. Munford on the CAP design issue
20 identified. If, for whatever reason, a pre-existing arrearage of a residential customer is
21 not subject to collection in the absence of CAP participation, that arrearage should not be
22 included in the arrearage forgiveness component (or any other component) of CAP.

Part 3. Rebuttal to CAUSE-PA Witness Brady.

Q. PLEASE EXPLAIN THE ISSUE ADDRESSED BY CAUSE-PA WITNESS BRADY TO WHICH YOU WISH TO RESPOND.

A. In CAUSE-PA Statement No. 1, witness Brady testified that he opposed the Company's proposal to allow the Company to implement "on-bill financing" as part of its WarmWise A&R program without prior Commission approval. According to Mr. Brady, "I do not think that this is the sort of program change that Columbia should be permitted to undertake without Commission approval and stakeholder input." (CAUSE-PA Statement 1, at 16). Mr. Brady stated that "[t]here are many, many questions about whether these programs are in the best interests [of] low and moderate income households." (CAUSE-PA Statement 1, at 17). I agree.

Mr. Brady asserts in his testimony that "[e]ven assuming it is possible to guarantee bill neutrality, a host of other concerns remain." (CAUSE-PA Statement No. 1 at 17). I think another important question is whether such a proposal presents issues that would best be decided after stakeholder comments and (likely) an evidentiary presentation. Such questions might include, but not be limited to:

- What occurs when savings are smaller than projected or when installed measures do not perform as expected?
- To what extent would the Company carry out a complete ability-to-repay underwriting examination before approving on-bill-financing?
- How does the Company propose to disclose the costs and risks associated with on-bill-financing, especially the risks associated with defaulting on loan repayment?

- What caps, if any, are there addressing the amount of repayment as a proportion of estimated savings?
- How do the terms of on-bill-financing differ when usage reduction involves “deep” energy efficiency treatment, with longer payback periods required?
- What quality assurance is offered on the installation of usage reduction measures? Who bears the liability for any lack of quality?
- What limits are placed on the ratio of on-bill-financing to the value of a property? Is there any required minimum equity holding in a property to access on-bill-financing?
- Are some consumers (e.g., older homeowners with substantial equity but little extra monthly cash) particularly vulnerable to on-bill-financing abuse? If so, what special protections are provided?
- What is the experience of previously existing on-bill-financing programs (e.g., NYSERDA, Oregon)?
- How does the on-bill-financing treat homeowners who already have mortgage debt that exceeds the value of their home?
- Is there a difference in on-bill-financing between homeowners and renters?
- How will the Company guard against abusive loan terms? Against high-pressure sales tactics? Against deceptive sales tactics?
- How would the on-bill financing program allocate rights and responsibilities against assignees of the original creditor relative to the original seller/creditor?
- How does the on-bill-financing treat the transfer of on-bill-financing obligations from one customer to a subsequent customer when the two customers have different credit profiles and/or creditworthiness characteristics?
- Who is responsible for the repayment of on-bill-financing loans in the event that a premise is vacant for an extended period of time?

- 1 ➤ If the repayment obligation runs with the customer and the customer refuses to
2 pay, will the dollar amount remaining on the repayment fall into the utility's
3 uncollectible accounts (to be paid by utility ratepayers)?
4

5 In May 2012, the Commission declined to allow on-bill financing of electric Energy
6 Efficiency & Conservation measures and recommended that a working group be
7 convened to gather information. Energy Efficiency and Conservation Program, Docket
8 Nos. M-2012-2289411, M-2008-2069887, Tentative Implementation Order at 22-23
9 (May 11, 2012).

10
11 Based on these observations, it would seem that in responding to the concerns identified
12 by Mr. Brady, in addition to the types of questions I identify above, the Company, the
13 Commission, the OCA, and other stakeholders would likely benefit not simply from the
14 input of stakeholders experienced with utility regulation and energy efficiency, but also
15 from the input of stakeholders with experience in mortgage finance, housing
16 development, and consumer credit.

17
18 **Q. PLEASE SUMMARIZE YOUR TESTIMONY WITH RESPECT TO ON-BILL**
19 **FINANCING?**

20 A. I do not offer an opinion, for purposes of this proceeding, on whether an on-bill financing
21 program for low- and moderate-income customers is a “good” or a “bad” proposition
22 generally. My testimony here is limited to agreeing with Mr. Brady’s assertion that it
23 would be inappropriate to allow the Company to implement an on-bill financing program
24 in the absence of PUC approval.

1 **Q. IS THERE A SECOND ISSUE RAISED BY MR. BRADY TO WHICH YOU WISH**
2 **TO RESPOND?**

3 **A.** Yes. Mr. Brady opposes the Company's proposed payment of \$50,000 to help fund
4 Southwest 2-1-1 services. According to Mr. Brady, while he sees the 2-1-1 service "is
5 *itself a valuable service to the community that is worthy of support, it is not clear. . .what*
6 PA 2-1-1 Southwest will do differently if it receives this money versus if it does not. If
7 Columbia funds PA 2-1-1 Southwest to the tune of \$50,000 callers will receive the same
8 information." (CAUSE-PA Statement No. 1, at 15).

9
10 As Mr. Brady observes, we do not know what PA 2-1-1 Southwest will do differently if it
11 receives this money versus if it does not. It is also not possible to determine that the
12 services offered by the 2-1-1 program will be directed to gas customers "experiencing
13 temporary emergencies" or how Columbia's customers would benefit. The Company has
14 provided no data collection, nor has it provided any means through which to assess the
15 outcomes of or the success of the "pilot." The Company has provided for no reporting,
16 no evaluation, no measurement, no determination of whether its \$50,000 generates an
17 incremental positive outcome for low-income customers.⁵

18
19 Moreover, it is my understanding that several western Pennsylvania utilities intend to file
20 a Petition with the Commission regarding PA 2-1-1 Southwest, which will raise a broad
21 spectrum of issues, including Mr. Brady's concern. I agree with Mr. Brady that

⁵ Moreover, if PA 2-1-1 is not available to the York County customers of Columbia Gas, those customers would be paying for the service with no means to access benefits from the service.

1 Columbia's funding proposal should not be approved in the context of this proceeding
2 and that it be addressed in the generic proceeding instead.

3

4 **Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?**

5 A. Yes.

6 165220

Appendix A: Colton Qualifications

Summary of Experience: Roger Colton

Roger Colton is a partner in the firm Fisher, Sheehan & Colton, Public Finance and General Economics (FSC) of Belmont, Massachusetts. An attorney and an economist, Roger engages in legal and technical research, program design and program evaluation. His work on helping to design, implement and fund low-income affordability programs has been with state and local governments; with the federal government; with natural gas, electric and water utilities; and with a variety of community-based organizations in more than 35 states.

Roger authors the annual Home Energy Affordability Gap, which calculates the dollar difference between actual home energy bills and affordable home energy bills on a county-by-county basis for the entire country. In 2003, he created the Home Energy Insecurity Scale for the federal LIHEAP office, a tool for measuring the outcomes of energy assistance programs that is being incorporated into program evaluation nationwide.

Roger was the recipient of the 1998 National Low-Income Energy Consortium (NLIEC) individual achievement award for career accomplishment with respect to low-income energy issues. He received the 2001 Sister Pat Kelley Award from the National Fuel Funds Network (NFFN) for his career-long work in helping to create and support fuel funds nationwide.

Outside his professional work, Roger is the Chair of the municipal Energy Committee for Belmont (MA); chair of the Solar Selection Oversight Committee for the Belmont Public Schools; Belmont's representative to the Massachusetts Municipal Energy Group (MMEG); a member of the solar contractor selection committee for the Boston-based Metropolitan Area Planning Council (MAPC), and the coordinator of the Belmont Affordable Shelter Fund (a local crisis intervention fund).

Roger is a professional juggler and is a member of the International Jugglers Association. He has reportedly been seen rooting for the Boston Red Sox.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Rebuttal Testimony (OCA Statement 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:

34 WARNICK ROAD
BELMONT, MA 02478

DATED: 8/10/13

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