I&E Statement No. 1
Witness: Emily Sears

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Direct Testimony

of

Emily Sears

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket Nos. R-2012-2321748**
	:	**M-2012-2323645**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION OF THE
BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Emily Sears, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as I&E Statement No. 1, I&E Exhibit No. 1, I&E Statement No. 1-SR, and I&E Exhibit No. 1-SR were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Emily K Sears

Emily Sears
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: February 13, 2013

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INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Emily Sears. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. My educational and professional background is set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in rate proceedings. The I&E analysis and testimony in this proceeding is based on its responsibility to represent the public interest.

Q. DEFINE THE "PUBLIC INTEREST."

A. The public interest refers to jurisdictional ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address the rate of return, including the cost of common equity, and the overall fair rate of return for Columbia Gas of Pennsylvania, Inc. (Columbia or Company).

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A RATE CASE?

A. Rate of return generally is the amount of revenue an investment generates (in the form of net income), usually expressed as a percentage of the amount of capital invested, over a given period of time. Rate of return is one of the components of the revenue requirement formula.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

$$RR = E + D + T + (RB \times ROR)$$

Where:

RR = Revenue Requirement

E = Operating Expense

D = Depreciation Expense

T = Taxes

RB = Rate Base

ROR = Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that rate is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of thc ratc of return and the proper valuation of the Company's ratc base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one which will allow the utility the opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia*, 292 U.S. 679, 692-93 (1923), and the *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1) A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures;

2) A utility is entitled to a return level reasonably sufficient to assure financial soundness;

3) A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital;

4) A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE OVERALL RATE OF RETURN.

A. The overall rate of return in this rate proceeding is calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, the Company's capital structure must first be determined by calculating the percentage of each capitalization component which has financed the rate base to total capital. The capital components consist of short-term debt, long-term debt, and common equity. Next, the effective cost rate of each capital structure component must be determined. The cost rate of debt is fixed, and can be computed accurately. The cost rate of common equity is not fixed, and it is more difficult to measure; therefore a proxy group is used as discussed later in this testimony. Next, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The I&E table below demonstrates the interaction of each capital structure component and its corresponding effective cost rates. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of the Company's revenue requirement.

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION IN THIS CASE.

A. I recommend the following rate of return for Columbia:

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.11 %	5.64 %	2.49 %
Short Term Debt	3.57 %	1.60 %	0.06 %
Common Equity	52.32 %	8.51 %	4.45 %
Total	100.00 %		7.00 %

Source: I&E Exhibit No. 1, Schedule No. 1, Page 1.

COMPANY POSITION

Q. PLEASE SUMMARIZE THE COMPANY'S RATE OF RETURN CLAIM IN THIS CASE.

A. Company witness Paul Moul recommended the following rate of return for Columbia:

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

Source: Columbia Exhibit No. 400, Page 1 of 30, Schedule 1 [1 of 1].

PROXY (BAROMETER) GROUP

Q. WHAT IS A PROXY GROUP, AS USED IN BASE RATE CASES?

A. A proxy group, also called a barometer group, is a group of companies which act as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A BAROMETER GROUP?

A. A barometer group is typically utilized since the use of data exclusively from one company may be less reliable than using a barometer group. The lower reliability occurs because the data for one company may be subject to events which can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these particular circumstances, and would therefore not be representative of similarly situated companies. The use of a barometer group has the effect of smoothing out potential anomalies associated with a single company.

A barometer group cost of equity is also used as a benchmark to satisfy the long established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return equal to that of similar risk enterprises.

Q. ARE THERE ANY ADDITIONAL REASONS FOR USING A BAROMETER GROUP IN THIS CASE?

A. Yes. Many public utility companies are not publicly traded, and therefore lack specific market data. A barometer group provides that industry specific market data.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR BAROMETER GROUP COMPANIES?

A. When selecting a barometer group, I used the following criteria: 1) 50% or more of the company's revenues must be generated from the natural gas distribution industry; 2) the company's stock must be publicly traded; 3) investment information for the company must be available from more than one source; 4) the company must not be currently involved/targeted in an announced merger or acquisition; and 5) the company must have 5 years of historic earnings data.

Q. WHAT CRITERIA DID MR. MOUL USE IN SELECTING HIS BAROMETER GROUP COMPANIES?

A. Mr. Moul used the following criteria in selecting his barometer group: 1) engaged in similar business lines; 2) have publicly-traded common stock; 3) are included in the Value Line Investment Survey; 4) are not currently the target of a merger or acquisition; and 5) are not engaged in significant non-gas utility operations.[1]

Q. WHAT BAROMETER GROUP DID YOU USE IN YOUR ANALYSIS?

A. I selected AGL Resources, Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas, Piedmont Natural Gas Co., and Southwest Gas Corp.[2]

Q. WHAT BAROMETER GROUP DID MR. MOUL USE IN HIS ANALYSIS?

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[1] Columbia Statement No. 10, page 4.

[2] I&E Exhibit No. 1, Schedule No. 1, page 2.

A. Mr. Moul selected AGL Resources, Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas, Piedmont Natural Gas Co., South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc.[3] Mr. Moul explains that he eliminated NiSource Inc. and UGI Corporation from his barometer group due to operation differences and diversification.[4]

Q. PLEASE EXPLAIN WHY YOU HAVE EXCLUDED NISOURCE INC., UGI CORPORATION, SOUTH JERSEY INDUSTRIES, AND WGL HOLDINGS FROM YOUR BAROMETER GROUP.

A. I have excluded all four companies as they violate my first criterion that 50% or more of the company's revenues must be generated from the natural gas distribution industry.

<u>CAPITAL STRUCTURE</u>

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

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[3] Columbia Exhibit No. 400, page 5 of 33, Schedule 3 [2 of 2].

[4] Columbia Statement No. 10, page 3, lines 20-22.

A. I recommend using the Company's claimed capital structure of 47.68% long-term debt, which includes 3.57% short term debt, and 52.32% equity for the future-test year ending June 30, 2014.[5]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Moul states that these capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.[6]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The capital structure, as measured in I&E Exhibit No. 1, Schedule No. 2, is representative of the barometer group.

COST RATE OF LONG-TERM DEBT

Q. WHAT IS THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

[5] Columbia Exhibit 400, page 1 of 33, Schedule 1 [1 of 1].

[6] Columbia Statement No. 10, page 17 lines 5-7.

A. Mr. Moul calculates the Company's claimed cost rate of long-term debt to be a weighted cost rate of 5.80% based on the Company's long-term debt issues expected to be outstanding at June 30, 2014.[7]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Company's claim of 5.80% is based on prior debt issuances, plus estimates of future issuances at a cost rate based on the Treasury yield plus a 266 basis point spread. This spread was obtained from Reuter's Corporate Bond Spread Tables for a BBB- credit rating as of 8/27/2012.[8]

Q. DO YOU AGREE WITH COLUMBIA'S CALCULATION FOR THE COST RATE OF LONG-TERM DEBT?

A. No. While the past debt issuances are contractual, the future debt costs are only an estimation. I&E Exhibit No. 1, Schedule No. 2, page 1 shows the historical spread between the 30-year Treasury bond and Columbia's actual debt issuances. The average spread is 1.99%, making Columbia's proposed 2.66% spread 68 basis points higher than its own average spread. The Company has not demonstrated that the 266 basis point spread for a BBB-

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[7] Columbia Exhibit No. 400, Page 12 of 33, Schedule 6 [3 of 3].

[8] Reply to I&E-RR-78-D

credit rating is a better indicator of the Company's future debt cost rates than its own actual 199 basis point spread.

Furthermore, the Mergent Bond Record shows that Public Utilities rated Baa have yields averaging 4.96% in 2012.[9] Therefore, Columbia's projected debt cost rates are at least 50 basis points higher than the industry average Baa rated public utility bonds. Furthermore, the Mergent Bond Record shows that interest rates are at a historical low, allowing Columbia the opportunity to obtain debt for less than it has historically.

Q. WHAT IS YOUR RECOMMENDATION REGARDING COLUMBIA'S LONG-TERM DEBT COST RATE?

A. I recommend an overall long-term debt cost rate of 5.64%. I further recommend that going forward Columbia provide I&E all documentation, including all term sheets or estimates from investment bankers, and the final loan document for each estimated debt issuance listed in the case, to the Commission's Bureau of Technical Utility Services and I&E to ensure that the Company obtained the most reasonable rate.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED 5.64% COST RATE OF LONG-TERM DEBT?

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[9] I&E Exhibit No. 1, Schedule No. 2, page 2

A. I have based this calculation on the projected 30-year Treasury yields from Blue Chip Financial Forecasts as of December 1, 2012, plus Columbia's average spread of 1.99%. I have used the Consensus Forecasts for the quarter in which the debt is projected to be issued for the Treasury yield. After weighting all debt issuances, the overall debt cost rate is 5.64%. Using Columbia's own historical spread is a more appropriate indicator of Columbia's specific debt cost rates than the Corporate Bond Spread used by Mr. Moul.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION THAT COLUMBIA BE REQUIRED TO PROVIDE DOCUMENTATION OF EACH ESTIMATED DEBT ISSUANCE LISTED IN THIS CASE.

A. Using a fully projected future test year (FPFTY) is a recent development in Pennsylvania, and this is the first case in which it is utilized. Debt cost rates historically have been issued before the end of the future test year. However, by using a FPFTY in this case, the Company includes both historical and future issuances in the filing. The future debt cost rates filed by Columbia are estimates of the future and can change with interest rate changes. Therefore, I&E recommends that Columbia submit all documentation supporting the issuances of all future debts, including term sheets and estimates from investment bankers to TUS and I&E within 30 days of issuance to determine the effect using a FPFTY has on its debt costs and to ensure the future cost rate estimates remain reasonable.

<u>COST RATE OF SHORT-TERM DEBT</u>

Q. WHY IS SHORT-TERM DEBT INCLUDED IN THIS PROCEEDING?

A. Natural gas distribution companies (NGDC) are able to store gas. One option for NGDCs is to pump gas into storage during the summer months, when demand for gas is lower. Current gas storage is typically financed by short-term debt. Since ratemaking principles allow for the stored gas in rate base, the associated short-term debt is allowed in a company's capital structure.

Q. WHAT IS THE COMPANY'S CLAIM FOR THE COST RATE OF SHORT-TERM DEBT?

A. The Company's proposed cost rate of short-term debt is 1.90%, which represents the Company's forecasted cost of short-term debt for the FPFTY ending June 30, 2014 (Columbia Exhibit No. 400, Page 12 of 33, Schedule 6 [3 of 3]).

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED COST RATE OF SHORT-TERM DEBT?

A. Mr. Moul calculates the Company's claimed cost rate of short-term debt by adding a margin of 1.475% to the LIBOR rate. The basis for the 1.475% margin is the established interest rate calculation for the NiSource money pool.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMED COST RATE OF SHORT TERM DEBT?

A. No. In Columbia's prior rate case at Docket No. R-2010-2215623, the Company's claim for short term debt was 2.75%. The average over the past 2 years, as filed by Columbia is 1.32%.[10] Furthermore, the average spread between Columbia's claimed short term debt rate and the LIBOR rate for the last 2 years is 0.94%. When this spread is added to the LIBOR rate estimate of 0.4%, the result is 1.34%. Therefore, Columbia's current claim of the LIBOR rate of 0.4% and a 1.475% spread is overstated and unsupported.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COST RATE OF SHORT TERM DEBT?

A. I recommend using a short term debt cost rate of 1.60%.

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[10] Columbia Standard Data Request, Question No. GAS-ROR-016, Attachment A

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE A 1.60% COST RATE OF SHORT-TERM DEBT?

A. In the standard data request, Columbia presents the balance and rate for short term debt.[11] I have used the interest rates associated with the 4 months (out of 24) which had a balance. The average of those is 1.60%. Also, the rates have been decreasing in the last year, down to 1.37% in May 2012. Accordingly, Columbia's claimed 1.90% is not reasonable when compared with its own historical short-term debt cost rates.

COST OF COMMON EQUITY

COMMON METHODS

Q. WHAT METHODS ARE COMMONLY USED TO DETERMINE THE COST OF COMMON EQUITY?

A. There are four methods commonly used to determine the cost of common equity. The four methods are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP), and Comparable Earnings (CE) methods.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

[11] Columbia Standard Data Requests, Question No. GAS-ROR-016.

A. The theoretical basis for the DCF model is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF model assumes that investors evaluate stocks in the classical economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The Capital Asset Pricing Model describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. The method hypothesizes that the investor required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting that company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk) and (2) market risk (systematic risk) which is measured by a firm's beta. The CAPM only allows for investors to receive a return for bearing systematic risk. Unsystematic risk is assumed to be diversified away. Therefore it does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP MODEL?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stocks are riskier than debt, and, as a result, investors require a higher expected return on stocks than bonds.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The theoretical basis for the CE method is the economic concept of "opportunity cost", or the probable return available to investors from alternative investments of similar risk. Under this theory, when investors believe that the probable return from a given investment is not equal to that available from another investment of similar risk, the investor will shift its resources to the alternative investment.

Q. WHAT METHODS DO YOU RECOMMEND USING IN THIS CASE TO DETERMINE THE COST OF COMMON EQUITY?

A. I recommend using the DCF method as the primary method to determine the cost of common equity, and using the CAPM as a comparison to the DCF results.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF AND CAPM IN YOUR ANALYSIS.

A. I have used the DCF as the primary method because it based upon the concept that the receipt of dividends plus expected appreciation is the total return requirement determined by the market, it uses the utilities' own stock prices and growth rates and are directly employed in a formalistic calculation, it recognizes the time value of money and is forward-looking, and it has the most wide-spread regulatory acceptance.

I have further included a CAPM analysis as a comparison because of the increased interest by the Commission in confirming the DCF results submitted in base rate cases by the use of a second method. I believe that out of the three commonly used methods, other than the DCF, the CAPM should be used as this second method. The CAPM is based on the concept of risk and return, the betas of the companies being analyzed allow the CAPM to be company-specific, it has widespread use in the financial investment community, and it is forward-looking. However, there are several disadvantages to using the CAPM, which is why it is not used as a primary method.

Q. PLEASE EXPLAIN CAPM'S DISADVANTAGES.

A. The relevancy of the CAPM (and therefore, the RP method) does not carry over from the investment decision making process into the regulatory process. The CAPM and RP method give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. By comparing CAPM and RP results with the current expected equity returns (DCF results), an investor can make rational buy and sell decisions within their portfolio. The DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM and the RP method are less reliable indicators because they measure the cost of equity indirectly, and risk premiums vary depending on the debt and equity being compared. Also, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or in the future.

Q. GIVEN THE FACT THAT ECONOMIC AND REGULATORY CONDITIONS TODAY CAN BE AND ARE OFTEN DIFFERENT FROM THE HISTORIC PERIOD, HOW DOES THIS AFFECT THE RESULTS FROM THE CAPM AND RP METHOD?

A. The CAPM and the RP method do not measure the current rate of return on common equity directly. Instead, the CAPM and the RP method determine the rate of return on common equity indirectly by observing the cost of debt. An implicit assumption when using the CAPM and the RP method is that the variables determining the equity cost rate and debt cost rate are the same, which allows the analyst to apply a constant risk premium (difference between risk free rate and the return on the market). However, the variables determining the cost rates in the two markets affect the cost rates differently, leading to a changing risk premium. The use of a constant risk premium fails to capture the effect of changing economic conditions on risk premiums over time. While the risk premium is the result of a comparison of two factors over time, the DCF's constant growth rate is derived directly from the stock, and is not a comparative factor.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, which appeared in the *New York Times* on February 18, 1992, summarizes a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French (I&E Exhibit No. 1, Schedule No. 3). Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory, the higher a stock's beta, the higher the expected return on that stock. They found that the model did not do well in predicting actual returns, and suggest the use of more elaborate multi-factor models. A more recent article in the *Journal of Economic Perspectives* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor, poor enough to invalidate the way it is used in applications" (I&E Exhibit No. 1, Schedule No. 4). As a result of this information, I believe investors will place less credibility on a model that is academically proven not to accurately predict returns. Moreover, the relevancy of the CAPM does not carry over from the investment decision making process into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP AND CE MODELS IN YOUR ANALYSIS.

A. The RP method is excluded due to the fact that it is a simplified version of the CAPM and is subject to the faults listed above, and it does not recognize company specific risk through beta. The CE method is excluded because it is subjective as to what are comparable companies, it is debatable whether historic accounting values are representative of the future, and the Commission has long recognized the problem with this method.

Q. WHAT IS THE COMMISSION'S HISTORICAL TREATMENT OF THE COMPARABLE EARNINGS APPROACH?

A. Regarding to the use of non-utility companies' historical book earnings in an attempt to determine a cost of equity for a utility the Commission stated:

> The use of nonregulated companies as a comparable group for regulated firms under the comparable earnings method of computing a rate of return on common equity requires

> numerous unsupportable assumptions and results in a highly speculative finding.

Pennsylvania Public Utility Commission v. Philadelphia Electric Co. (1980) 33 Pur 4th 319, 341.

> NFGD employed comparable earnings as a check on the common equity cost rates produced by its other methodology. NFGD M.B. p. 170. NFGD did not use comparable earnings as a common equity cost rate determinant. Additionally, it was noted that comparable earnings are not market related but accounting related ratios.

Pa. PUC v. National Fuel Gas Distribution Corp., Docket No. R-00940021, p. 199, Order entered December 1, 1994.

SUMMARY OF COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. Moul testifies that in analyzing the Company's cost of equity, he relied on four well-recognized measures: the DCF, the RP analysis, the CAPM, and the CEM.[12] Mr. Moul then lists the results for each measure, based on his barometer group of nine gas companies:

[12] Columbia Statement No. 10, pages 2-4.

Measure	Gas Group
DCF	10.55 %
Risk Premium	11.01%
CAPM	11.13%
CE method	12.70%
Average	11.35%
Median	11.07%[13]

Mr. Moul then recommends a cost of equity in the range of 11.0% - 11.3%. In addition, Mr. Moul recommends that in recognition of Columbia's outstanding performance, it should be granted an opportunity to earn an 11.25% rate of return on common equity, which is ten basis points above the midpoint of his range.

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. Based upon my analysis, I recommend a cost of common equity of 8.51%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

[13] Columbia Statement No. 10, page 4.

A. I arrived at this equity return using the DCF method. I used the CAPM method only as a comparison to my DCF results. My DCF analysis employed a spot dividend yield, a 52 week dividend yield, and earnings growth forecasts.

DISCOUNTED CASH FLOW (DCF)

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the standard discrete DCF model as portrayed in the following formula:

$$k = D_1/P_0 + g$$

Where:

k	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate of dividends

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by ½ the expected growth rate [14] in order to account for changes in the dividend paid in period 1.

[14] The adjustment of ½ the growth rate is used when the timing of the dividend increase is not known for certain. It could occur next month, or in the twelfth month. On average, it is safe to assume that the increase will occur half way through the prospective year. Therefore, an adjustment by ½ the expected growth rate is appropriate.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of short-term anomalies and "stale" data series. For purposes of my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot, and 52 week average dividend yield. The following table summarizes my dividend yield computations for the barometer group:

Seven Company Barometer Group	Dividend Yield
Spot	4.23%
52 week average	3.91%
Average	4.07%

Source I&E Exhibit No. 1, Schedule 5.

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have examined the earnings growth forecasts.

Q. PLEASE EXPLAIN YOUR USE OF EARNINGS GROWTH FORECASTS.

A. I have used five year projected growth rate estimates from established forecasting entities including Value Line, Yahoo! Finance, MSN Money, and Morningstar.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected growth rates for the seven company barometer group are presented in I&E Exhibit No. 1, Schedule No. 6. The growth rates are 2.95%, 6.06%, 3.45%, 3.98%, 4.05%, 4.59%, and 6.02%. The average of the seven companies' growth rate forccasts is 4.44%.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE RESULTS FOR THE 5 YEAR PROJECTED GROWTH RATES?

A. Yes. While these 5 year projected growth rates can be used in analyses, one must be aware that analysts' estimates may be biased. This bias has been observed in literature.

Q. PLEASE EXPLAIN.

A. An article authored by Professors Ciciretti, Dwyer, and Hasan in 2009 observed strong support of earnings forecast being higher than actual earnings.[15] In spring of 2010, McKinsey On Finance presented an article reporting that after a decade stricter regulation analysts' forecasts are still overly optimistic[16]

Analysts' estimates are an attempt to forecast future cash flows and thus expected earnings growth. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings. If the base year earnings are abnormally high, the growth rates from which they are calculated will be biased downward. Similarly, if the base year earnings are abnormally low, the growth rates from which they are calculated will be biased upward. As a result, it is typically necessary to employ a methodology to smooth out the abnormally high or low base year earnings.

Q. WHAT METHODOLOGY DO YOU RECOMMEND TO DETERMINE A MORE APPROPRIATE LONG TERM GROWTH RATE?

A. I typically recommend using a log-linear regression analysis.

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[15] Ciciretti, Rocco; Dwyer, Gerald R; and Iftekhan Hasan. "Investment Analysts' Forecasts of Earnings" Federal Reserve Bank of St. Louis *Review*, September/October 2009, 91 (5, part 2) pp. 545-67,

[16] Goedhart, Marc J; Raj, Rishi; and Abhishek Saxena. "Equity analyst: Still too bullish" McKinsey On Finance Number 35 Spring 2010, pp. 14-17.

Q. WHAT IS A LOG-LINEAR REGRESSION, FOR THE PURPOSES OF DETERMINING A GROWTH RATE?

A. A log-linear regression is a standard time-series linear regression in which data points are plotted as natural logarithms.

Linear regression analysis assumes that a linear relationship exists between two variables. This means that if the two variables were plotted on a graph, a straight line would take shape, and a best fit line could be calculated. However, in certain cases, raw growth data was plotted and instead of a straight line being formed, a hyperbola was formed. In these cases, the data must be transformed before a regression, or a best fit line, can be calculated. To create a linear relationship with the growth data, the earnings per share must be transformed by the natural log, or log with a base e. The log transformation converts the compound growth pattern to a linear growth pattern. The natural log data is then plotted and the slope of the best fit line is determined; this slope is the growth rate, but in natural log form. To make the slope meaningful, one calculates the antilog to arrive at a meaningful growth rate.

Q. WHEN CAN A LOG-LINEAR REGRESSION ANALYSIS BE USED?

A. A log-linear analysis can be used when earnings and dividend growth rates have been relatively stable, and if investors expect these trends to continue.

This has been the case for some time now, and therefore I typically use this method to arrive at a representative growth rate.

Q. WHY HAVE YOU NOT USED A LOG-LINEAR REGRESSION ANALYSIS IN THIS PROCEEDING?

A. I have not used a log-linear analysis because the historical growth in earnings is not indicative of the future growth in earnings for the gas utility industry at this point in time.

Q. PLEASE EXPLAIN.

A. We are currently at an "inflection point." An inflection point is an event that results in a significant change in the progress of a company. This change for the gas industry is the aggressive pipeline replacements. Historically, gas utilities have had a stable rate at which capital projects were completed; however, much of the gas utility industry's pipe has now reached the end of its useful life, therefore needing replaced. The industry plans on aggressively replacing the majority of this pipe within the next twenty years. This translates into replacing fully depreciated plant with new plant, thereby increasing rate base. Rate of return is applied to this increased rate base, thereby increasing earnings. It is this growth in earnings which causes the growth rate to be different from its historical rates.

It is also the magnitude of the replacement of depreciable plant which causes a bigger increase in earnings than the smaller, regular capital projects. Therefore, at this time, a log-linear analysis has not been performed, as the historical growth is not indicative of future growth.

Q. CAN A LOG-LINEAR ANALYSIS BE USED IN THE FUTURE?

A. Yes. After sufficient time has passed (eg. 5 years of historical data, or 2 years of no change in growth), and the new trend emerges, a log-linear analysis will again be performed to arrive at a representative growth rate. This is because the historical rate of pipe replacement will again be indicative of the future rate of pipe replacement.

Q. WHAT ARE THE RESULTS OF YOUR DISCOUNTED CASH FLOW ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELDS AND GROWTH RATES?

A. Using a dividend yield of 4.07% and a growth rate of 4.44%, the DCF result is 8.51% (I&E Exhibit No. 1, Schedule No. 7).

CAPITAL ASSET PRICING MODEL (CAPM)

Q. EXPLAIN YOUR LIMITED USE OF THE CAPM MODEL.

A. I have included a CAPM analysis as a result of an increased interest by the Commission in confirming the DCF results submitted in base rate cases by the use of a second method.

Q. **PLEASE EXPLAIN YOUR CAPM ANALYSIS.**

A. My analysis employs the standard CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

k	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock
β	=	Beta measures the systematic risk of an asset

The CAPM formula above is actually a form of the more general risk premium approach and is based on modern portfolio theory.

Q. **WHAT IS BETA, AS EMPLOYED IN YOUR USE OF THE STANDARD CAPM MODEL?**

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by running a linear regression of a stock's return against the return on the overall stock market. The beta of a stock with an identical price pattern as the overall stock market will have a beta of 1. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than 1, and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than 1, and would be described as having less investment risk than the market.

Q. WHAT BETA DID YOU CHOOSE FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for the group of seven natural gas distribution companies, I am using the average of the betas for the companies as provided in the Value Line Investment Survey. As shown on I&E Exhibit No. 1, Schedule No. 8, the average beta for the seven company barometer group is 0.66.

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU CHOSEN FOR YOUR CAPM ANALYSIS?

A. For my CAPM analysis, I have chosen to use the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Bonds. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free yield, this yield can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At the other extreme, the 30-year Treasury Bond yield exhibits more stability, but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with the market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I chose to use the projected yield on the 10-year Treasury Bond because it balances the short comings of the other two alternatives. As shown on Schedule No. 9, [17] the yield on the 10-year Treasury Bond is expected to range between 1.64% and 3.90% over the next five-years. For my analysis, I chose 2.26%, which is the average of the yields.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE RETURN ON THE OVERALL STOCK MARKET, AS EMPLOYED IN YOUR CAPM ANALYSIS.

A. To arrive at a representative expected return on the overall stock market, I surveyed three sources. As shown in Schedule No. 10,[18] Value Line expects its universe of 1500 stocks to have an average yearly return of 14.77% over the next 3 to 5 years, based on a forecasted dividend yield of 2.30% and a yearly index appreciation of 60%. Yahoo! Finance expects the S&P 500 index to have an average yearly return of 10.30% over the next 5 years, based upon a forecasted dividend yield of 2.46% and an expected

[17] Exhibit No. 1, Schedule No. 9.

[18] Exhibit No. 1, Schedule No. 10.

increase in the S&P 500 index of 7.84%. A historical return for the S&P Composite Index is routinely used as a benchmark for the expected return on the overall stock market. This component can vary widely depending on the historic period used.

Q. EXPLAIN THE RANGE OF EXPECTED RETURNS ON THE OVERALL STOCK MARKET YOU CALCULATED USING THE HISTORICAL RETURN FOR THE S&P COMPOSITE INDEX.

A. Using the geometric mean of historic returns, I calculated the following results:

Time Period	Return
5 Years	(0.25)%
10 Years	2.92%
20 Years	7.81%
40 Years	9.83%
86 Years	9.77%
Average	6.02%

Source: I&E Exhibit No. 1, Schedule No. 10, p. 2.

Q. WHY HAVE YOU SELECTED THESE TIME PERIODS?

A. I have selected the above time periods to represent a variety of investor experiences and time horizons. The 86 year time period represents the longest measurable time period available for the S&P Composite Index. The 40 and 20-year time periods coincide with the average useful lives of a utility's assets. The 10-year time period corresponds with the Treasury Bond I have employed. The 5-year time period corresponds with time period the DCF growth rates are projected.

Q. WHAT ARE THE EXPECTED RETURNS ON THE OVERALL STOCK MARKET BASED ON YOUR FORECASTED AND HISTORIC CAPM ANALYSIS?

A. The results of these return calculations are presented on I&E Exhibit No. 1, Schedule No. 11. These expected returns on the overall market are 12.54% for my forecasted analysis and 6.02% for my historical analysis.

Q. WHAT ARE THE COST OF EQUITY RESULTS FROM YOUR FORECASTED AND HISTORIC CAPM ANALYSES?

A. The results of these two analyses are as follows:

	CAPM cost of equity
Forecasted	9.08%
Historic	4.75%

Source: I&E Exhibit No. 1, Sch. 11.

Q. HOW DID YOU INCORPORATE THESE RESULTS INTO YOUR OVERALL COST OF EQUITY?

A. I have included the results of my CAPM analysis in my overall cost of equity calculation only as a comparison to my DCF result. The DCF model measures the cost of equity directly by measuring the discounted present value of future cash flows of the company and it is these cash flows that actually pay dividends to shareholders. The Commission has expressed interest in seeing the results of other models to confirm the results of DCF. The CAPM is a commonplace cost of equity measure to confirm the reasonableness of the DCF.

Q. WHY DID YOU NOT GIVE THESE RESULTS A SPECIFIC WEIGHT IN DETERMINING YOUR COST OF COMMON EQUITY?

A. I have not given these results a specific weight in determining my cost of common equity because of the flaws in the CAPM model that I have expounded upon earlier in my testimony. The CAPM model is flawed, first theoretically because it measured the cost of equity indirectly through the cost of a risk free asset and second in practice because it can be manipulated by the time period used to calculate the overall market return.

CRITIQUE OF COMPANY RECOMMENDATION

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ITS COST OF EQUITY ANALYSIS?

A. Mr. Moul adjusted his indicated cost of common equity upward 64 basis points to account for leverage, and upward 76 basis points to account for

Columbia's claimed higher financial risk relative to the proxy group. Mr. Moul further adjusted his indicated cost of common equity upward by 114 basis points to reflect Columbia's claimed higher business risk due to its small size relative to his proxy group. Finally, Mr. Moul adjusted his indicated cost of common equity upward by 10 basis points to reflect Columbia's claim of exemplary performance of the Company's management. The rate payer impact of each of these upward adjustments proposed by the Company is as follows:

Leverage adjustment	+0.64% = $5,966,000
Financial adjustment	+0.76% = $7,020,000
Size adjustment	+1.14% = $10,529,000
Management Performance	+0.10% = $1,054,000

Q. DO YOU AGREE WITH MR. MOUL'S PROPOSED COST OF EQUITY?

A. No. Mr. Moul's cost of equity recommendation is biased due to several errors. Mr. Moul has given undue weight to the Risk Premium and Comparable Earning methods. He also employs an inflated DCF growth rate, an uncalled for dividend yield adjustment and inflated CAPM betas. Finally, Mr. Moul has made uncalled for financial, leverage, size risk and management performance adjustments.

WEIGHTS GIVEN TO METHODS

Q. DO YOU AGREE WITH THE COMPANY'S RELIANCE ON THE USE OF THE CAPM, RP, AND CE MODELS?

A. No. While I am not opposed to using the CAPM results as a comparison to the results of the DCF calculation, it is inappropriate to give the CAPM, RP, and CE models comparable weight, as I have discussed previously. Furthermore, Mr. Moul's CE method contains limitations and his approach is faulty.

Q. WHAT ARE THE LIMITATIONS OF THE COMPARABLE EARNINGS APPROACH?

A. The CE approach employed by Mr. Moul compares projected returns of companies of dissimilar business and financial risk.

Q. EXPLAIN HOW MR. MOUL'S CE APPROACH IS FAULTY.

A. The companies in Mr. Moul's analysis are not utilities, thus they are too dissimilar to be used in a Comparable Earnings analysis. The companies in Mr. Moul's CE barometer group are simply not comparable to gas utilities in terms of their business risk /financial risk profile. Gas utilities, being monopolies with very low business risk, are able to maintain higher financial risk profiles by employing more leverage. Conversely, Mr. Moul's CE barometer group companies, being in an unregulated competitive environment with much higher business risk, must maintain lower financial risk profiles by employing a smaller amount of leverage.

<u>**INFLATED DCF GROWTH RATES**</u>

Q. WHAT GROWTH RATE HAS MR. MOUL CHOSEN FOR HIS DCF ANALYSIS?

A. Mr. Moul has chosen a growth rate of 5.25%.

Q. WHAT IS THE BASIS FOR MR. MOUL'S GROWTH RATE?

A. Mr. Moul ascertains growth rates of 4.89%, 4.80%, 4.53% and 5.88%.[19] Mr. Moul then determines that a 5.25% growth rate is appropriate. Mr. Moul also states that the <u>Value Line</u> forecast of dividend per share growth is inadequate due to the forecasted decline in the dividend payout ratio.

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS?

A. No. Mr. Moul skews his growth rates upward for an unsupported assumption that today's forecasts are understated.

[19] Columbia Statement No. 10, page 23, lines 25-26.

Q. PLEASE EXPLAIN.

A. Mr. Moul claims that today's forecasts are understated, yet has no support for this claim. Mr. Moul uses the historical 5 and 10-year growth rates to show that the growth rates are currently lower than they were 5-10 years ago. This is to be expected since the Great Recession only occurred 4 years ago. This would lead historical growth rates to be higher than current growth rates, as the economy is only slowly recovering.

The average of all 5 of Mr. Moul's industry growth rates is 5.0%. Mr. Moul then uses a growth rate of 5.25%, which is higher than 4 out of his 5 growth rates.

Also, as I have discussed earlier, reports have shown that analysts tend to overestimate earnings growth, further disputing Mr. Moul's claim.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR. MOUL'S GROWTH RATE STATEMENTS?

A. Yes. Mr. Moul's comments regarding the future of a dividend payout ratio decline are not presented in any context. There are many reasons for a decline in a dividend payout ratio, one such reason would be a company retaining more earnings for capital projects. This would be reasonable as the age of the pipes in the ground reach the end of their useful lives. Furthermore, if the dividend payout ratio were to increase, the dividend eventually would hit a ceiling or even decline, since the dividend payout ratio is simply the percentage of a company's earnings that are paid out in dividends. Consequently, Mr. Moul should not need to choose an outlier for his growth rate.

DIVIDEND YIELD ADJUSTMENT

Q. WHAT DIVIDEND YIELD ADJUSTMENT HAS MR. MOUL PROPOSED IN HIS ANALYSIS?

A. Mr. Moul has proposed an ex-dividend adjustment to the dividend yields of his barometer group. Mr. Moul adjusts the "month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date." (Columbia Statement No. 10, p. 19 line 24 – p. 20 line 1).

Q. IS MR. MOUL'S EX-DIVIDEND ADJUSTMENT APPROPRIATE?

A. No. Mr. Moul's ex-dividend adjustment is inappropriate for three reasons. First, my review of the academic literature fails to uncover any support for the application of an ex-dividend adjustment to the dividend yield in the DCF formula as proposed by Mr. Moul. Second, Mr. Moul has not provided any evidence in his testimony that suggests investors make this adjustment in the context of the DCF model. Finally, I am not aware of any financial publications that provide ex-dividend adjusted yields to investors that might be used for their financial investment decision making. Arguably, if such information were an important factor in an investor's decision making process then main-stream financial publications would include it on a regular basis.

Q. WHAT IS MR. MOUL'S DIVIDEND YIELD PRIOR TO HIS ADJUSTMENT?

A. Mr. Moul has used a dividend yield of 3.79% for the Gas Group before adjustments.[20]

LEVERAGE (MARKET-TO-BOOK) ADJUSTMENT

Q. WHAT IS FINANCIAL LEVERAGE?

A. Generally, financial leverage is the use of debt capital to supplement equity capital. A firm with significantly more debt than equity is considered to be highly leveraged.

Q. WHAT IS A MARKET-TO-BOOK RATIO?

A. Generally, a market-to-book ratio is used to evaluate a public firm's equity value. This is done by comparing a company's equity market value to a company's equity book value.

[20] Columbia Statement No. 10, page 20.

Q. WHAT ADJUSTMENT HAS MR. MOUL PROPOSED IN HIS ANALYSIS?

A. Mr. Moul proposes to make a 64 basis point "leverage" adjustment to account for applying a market valued cost of equity to a book valued equity capital structure (Columbia Statement No. 10, pages 26-27).

Q. IS THE TERM "LEVERAGE" APPROPRIATE FOR THIS TYPE OF ADJUSTMENT?

A. No. Mr. Moul does not propose to change the capital structure of the utility (a leverage adjustment), nor does he propose to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul is proposing to make an adjustment to account for applying the market value cost rate of equity to the book value of the utility's equity. Currently, there is no term in academic journals or text books that describes this type of adjustment.

Q. WHAT IS THE BASIS FOR MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. Mr. Moul theorizes that if regulators use the results of the DCF to compute the weighted average cost of capital based on a book value capital structure used for ratemaking purposes, the utility will not, by definition, recover its risk-adjusted capital cost.[21] Mr. Moul believes this is because market valuations of equity are based on market value capital structures, which in general have more equity, less debt and, therefore, less risk than book value capital structures.

Q. HOW DOES MR. MOUL CALCULATE THE LEVERAGE ADJUSTMENT USED IN HIS ANALYSIS?

A. Mr. Moul states:

> I know of no means to mathematically solve for the 0.64% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.64% adjustment is merely a convenient way to compare the 9.79% return computed directly with the Modigliani & Miller formulas to the 9.15% return generated by the DCF model based on a market value capital structure.[22]

Q. HOW DOES MR. MOUL CALCULATE THE 9.79% RETURN HE CLAIMS IS COMPUTED DIRECTLY WITH THE MODIGLIANI & MILLER FORMULAS?

A. Mr. Moul uses the following formulas found in Columbia Statement No. 10, Appendix E, pages 11 and 12:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D/E) - (ku - d)\ P/E$$

and $$ke = ku + (((ku - i)\ 1\text{-}t)\ D/E) + (ku - d)\ P/E$$

[21] Columbia Statement No. 10, page 26 lines 16 – 22.

[22] Columbia Statement No. 10, page 31, lines 16-21.

Where:

ku = cost of equity for an all equity firm

ke = market determined cost equity

i = cost of debt

d = dividend rate on preferred stock

D = debt ratio

P = preferred stock ratio

E = common equity ratio

Q. DO YOU AGREE WITH MR. MOUL'S "LEVERAGE ADJUSTMENT"?

A. No. Mr. Moul's adjustment is inappropriate for several reasons. These reasons include rating agency characterization of financial risk, Commission precedent, lack of support in academic literature, and circularity in Mr. Moul's formula for the adjustment.

Q. PLEASE EXPLAIN HOW RATING AGENCIES ASSESS FINANCIAL RISK.

A. Rating agencies assess financial risk based upon the company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements for their analysis, not market capital structure. True financial risk resides in the income statement, and is a function of the actual amount of interest expense and income volatility. Therefore, no matter how the Company's investments are valued in the market place, the financial risk does not change.

Q. PLEASE DISCUSS WHY COMMISSION PRECEDENT IS A REASON TO REJECT MR. MOUL'S "LEVERAGE ADJUSTMENT".

A. There are several cases in which the same "leverage adjustment" has been rejected. First, the Commonwealth Court in *Blue Mountain Consolidated Water Company v. Pennsylvania Public Utility Commission*, 57 Pa. Commonw. 363, 426 A.2d 724 (1981), stated that the "[R]ecord must be remanded to the Public Utility Commission for clarification of findings concerning fair rate of return." On remand, the Commission responded to the Court's request for clarification by identifying 7 principles that were applied to analyze the company's required and lawful rate of return. At 55 P.U.R. 502, p. 503-504 (1982) the Commission's third identified principle states in full:

> (3) Market price-book value ratios are not a goal of regulation but a result of regulation, general economic factors and individual company's characteristics of management, operations and perceived future. In general, we view a market-book ratio in the area of one-to-one as appropriate for regulated industry.

Second, in *Pennsylvania Public Utility Commission v. Metropolitan Edison Co.*, Docket No. R-00061366, p. 34 (Order entered January 11, 2007), the Commission did not accept the Company's financial risk increment related to the leverage difference between market capital structures and book value capital structures.

Third, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, (Order entered July 31, 2008), the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "[t]he fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases." Opinion at p. 38.

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, the Commission agreed with the I&E position and stated in the Order entered July 14, 2011, "any adjustment to the results of the market based DCF...are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment."

Q. MR. MOUL HAS CITED MODIGLIANI AND MILLER'S RESEARCH ON THE SUBJECT OF CAPITAL STRUCTURE AND

COST OF CAPITAL AS JUSTIFICATION FOR HIS LEVERAGE ADJUSTMENT. IS THIS APPROPRIATE?

A. No. Mr. Moul has misinterpreted Modigliani and Miller's theory and used it in a way the researchers never advocated. Modigliani and Miller's research primarily is to understand company capital investment behavior, not the financial risk associated with a stock's market price diverging from its book value. Also, the adjustment and formula employed by Mr. Moul cannot be found in the research he cites.

Q. EXPLAIN FURTHER WHAT THE WORK OF MODIGLIANI AND MILLER STATES ABOUT EFFECT OF THE TYPE OF CAPITAL EMPLOYED, DEBT OR EQUITY, UPON THE VALUE OF THE FIRM.

A. The work of Modigliani and Miller actually points to the opposite conclusion of Mr. Moul, "That is, the market value of any firm is independent of its capital structure."[23] Furthermore, "...the value of any firm must be independent of its financial structure."[24]

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[23] Modigliani, Franco and Miller, Merton H. "The Cost of Capital, Corporation Finance, and the Theory of Investment" *American Economic Review*, Jun58, p268.

[24] Modigliani, Franco and Miller, Merton H. "The Cost of Capital, Corporation Finance, and the Theory of Investment: Reply" *American Economic Review*, Jun65, p525.

Q. ARE YOU AWARE OF ANY OTHER ACADEMIC LITERATURE THAT SUPPORTS MR. MOUL'S "LEVERAGE ADJUSTMENT"?

A. No. I am not aware of any other academic literature that supports Mr. Moul's "leverage adjustment."

Q. ARE THERE FLAWS IN THE FORMULAS MR. MOUL USES IN HIS ANALYSIS?

A. Yes. First, the formulas employed by Mr. Moul do not appear anywhere in the research he cites. Second, his formula to determine the cost of equity of a 100% equity firm ("ku") does not actually determine the cost of equity of a 100% equity firm, but instead, the formula assumes the cost of equity of a 100% equity firm to be 7.94%. The effect of the assumed "ku" rate of 7.94% is amplified by its presence in the formula for the market determined cost of equity ("ke"). Finally, the literature Mr. Moul cites does not advocate using its native formulas in a DCF adjustment setting.

Q. CAN THE FORMULA SHOWN IN MR. MOUL'S APPENDIX E, AND STATED ON PAGE 46 AND 47 OF THIS TESTIMONY, BE FOUND IN THE MODIGLIANI & MILLER LITERATURE?

A. No, it cannot.

Q. DID MR. MOUL PROVIDE ANY OTHER SOURCE MATERIAL FOR THIS FORMULA?

A. Yes. Mr. Moul provided a copy of Regulatory Finance: Utilites' Cost of Capital, by Roger A. Morin, 1994.[25] Mr. Moul indicates that his formula comes from Dr. Morin's book, but only provided "relevant pages." Therefore, I have used the New Regulatory Finance book by Roger A. Morin, 2006, to review the formula. First, and the most importantly, this book is not peer reviewed; therefore, the formula is not academically vetted and cannot be relied upon. Secondly, Mr. Moul uses the information in ways the author has not advocated. Dr. Morin discusses the cost of equity in relation to an optimal capital structure, not in any relation to market and book capital structure, or in relation to the DCF. Thirdly, Dr. Morin provides the following conclusion on pages 463-464:

> Given that there are several theories of capital structure and that none has emerged as the victor, the one inescapable conclusion from the research is that debt affects the cost of equity and that a company has a different cost of equity at a different capital structure. Therefore, the capital structure used to estimate the cost of equity is an integral inseparable part of that estimate.

Since the capital structures in Mr. Moul's Gas Group are in line with that of Columbia's, and the actual amount of debt of the Company does not

[25] Reply to I&E-RR-18-D.

change, it would be erroneous to adjust the return determined by the barometer group.

Q. PLEASE EXPLAIN HOW MR. MOUL'S FORMULA DOES NOT ACTUALLY DETERMINE THE COST OF EQUITY OF A 100% EQUITY FIRM.

A. This can be seen easily on page E-11 of Mr. Moul's Appendix, or page 46 and 47 above. The formula "solving" for *ku*, cost of equity for an all-equity firm does not actually solve for "ku." As seen on page E-11, the term "ku" is listed on both sides of the equation. Since Mr. Moul is trying to solve for "ku," it should only be listed on one side. In order to solve for a variable in algebra, such as "ku" in this case, every appearance of that variable must be moved to one side. Mr. Moul's equation has not done this. Further, the "ku" on the right hand side of the equation is solved for before the left hand side "ku" is solved (which are the same factor). That is to say that "ku" is solved before "ku" is solved, which is a mathematical impossibility. There is also no source for the 7.94% on the right hand side of the equation, which is the "ku" variable. Therefore, Mr. Moul's 7.94% is an assumed arbitrary value, and cannot be relied upon.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. Yes. Value Line presents, in its publishing, the book value debt and equity ratios of the utilities, not the market value ratios. Consequently, investors base their decisions on book value debt and equity ratios for the regulated utilities, and no adjustment is needed.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE LEVERAGE ADJUSTMENT.

A. I recommend the rejection of the leverage adjustment because the formula used by Mr. Moul is faulty, there is no academic support for such an adjustment in a DCF setting, Commission precedent does not unequivocally support its use, true financial risk is a function of the amount of interest expense, and capital structure information provided investors through Value Line is that of book values, not market values.

INFLATED CAPM BETAS

Q. HOW HAS MR. MOUL INFLATED THE BETAS EMPLOYED IN HIS CAPM ANALYSIS?

A. Mr. Moul has used the same logic for inflating his CAPM betas that he used to enhance his DCF returns, through a financial risk, or leverage, adjustment.[26] Such enhancements are unwarranted for beta in a CAPM

[26] Columbia Statement No. 10, pages 40-41.

analysis for the same reasons that enhancements are unwarranted for DCF results. Also, if the unadjusted Value Line betas do not reflect an accurate investment risk, as Mr. Moul contends, the question naturally arises as to why Value Line does not publish betas that are adjusted for leverage. Until this type of adjustment is demonstrated in the academic literature to be valid, such leverage adjusted betas in a CAPM model should be appropriately rejected.

SIZE ADJUSTMENT

Q. WHAT IS MR. MOUL'S SIZE ADJUSTMENT?

A. Mr. Moul makes a 114 basis point adjustment because he believes that as the size of a firm decreases, its risk and hence, it's required return increases.[27] Further, Mr. Moul uses the SBBI Yearbook to argue that the returns for stocks in lower deciles had returns in excess of those shown by the simple CAPM.

Q. WHY IS MR. MOUL'S SIZE ADJUSTMENT UNNECESSARY?

A. Mr. Moul's size adjustment is unnecessary because while there is technical literature supporting adjustments relating to the size of a company, this literature is not specific to the utility industry. Furthermore, in addressing

[27] Columbia Statement No. 10, p. 42, lines 25-26.

the technical literature of SBBI, one can see that making an adjustment based on this source would be in error because it is not specific to utilities, suffers from the January effect, and is unpredictable.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT SUPPORTS THE LACK OF VALIDITY OF THE SIZE RISK ADJUSTMENT FOR UTILITY COMPANIES?

A. Yes. I&E Exhibit No. 1, Schedule No. 12, presents an article by Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," from the Journal of Midwest Finance Association in 1993, pp. 95-101, that concluded:

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industrials, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.

While this article is older, until a credible up-to-date article is provided to refute these findings, the size adjustment should be rejected.

Q. WHAT IS THE SBBI YEARBOOK REFERENCED PREVIOUSLY?

A. The SBBI Yearbook is the Ibbotson Stock, Bonds, Bills & Inflation Yearbook. There are two types, the Classic Yearbook and the Valuation

Yearbook. The Classic Yearbook is a leading source of historical market data and long-term market returns, and is updated yearly. The Valuation Yearbook presents the data, how to use it, presents current issues and controversies with alternative calculation methods, and new studies as they become available.

Q. CAN YOU EXPLAIN WHY MR. MOUL'S SIZE ADJUSTMENT SUFFERS FROM THE JANUARY EFFECT?

A. The size effect is seasonal and is sometimes called the January effect because virtually all of the small stock effect occurs in the month of January.[28] Therefore, the excess returns that Mr. Moul claims is attributable to a firm's size are also equally attributable to the month of January. Currently, there is no generally accepted explanation for this effect. To recommend regulatory support of a size premium present in only one month (January) is unreasonable.

Q. PLEASE DISCUSS THE UNPREDICTABILITY OF THE SBBI YEARBOOK'S SIZE PREMIUM.

A. The Ibbotson SBBI 2012 Valuation Yearbook states on pages 102-03:

[28] Ibbotson SBBI 2009 Classic Yearbook, page 101.

> By simple definition, one cannot expect risky companies to always outperform less risky companies; otherwise they would not be risky.

It continues:

> One thing that we do know about the size premium is that it is cyclical in nature...It is not unusual for the size premium to follow several years of consistently positive values with several years of consistently negative values...We should actually expect periods of small stock underperformance as well as over performance in the future.

It also states:

> One might observe the last 20 years of market data to see that the performance of large-capitalization stocks. In fact, large-capitalization stocks have outperformed small-capitalization stocks in four of the last ten years.

This information shows the unpredictability and variability of the size premium.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SIZE ADJUSTMENT?

A. Given the lack of evidence for the size adjustment as related to the utility industry, the seasonal effect, and the unpredictability and variability of the size premium, Mr. Moul's size adjustment should be rejected.

Q. WHAT IS MR. MOUL'S DCF RESULT, WITHOUT ANY OF HIS PROPOSED ADJUSTMENTS?

A. Mr. Moul's DCF result consists of an unadjusted dividend yield of 3.79% and an average growth rate of 5.0%, which results in an 8.79% cost of equity.

RISK ANALYSIS

NATURAL GAS RISK FACTORS

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING NATURAL GAS RISK FACTORS FOR COLUMBIA.

A. Mr. Moul believes that Columbia is risky for multiple reasons. First, he testifies that Columbia operates in a unique situation in western Pennsylvania with overlapping service territories, which creates competition.

Second, Mr. Moul maintains that Columbia is exposed to bypass risk due to six interstate pipelines in their service territory. Mr. Moul further maintains that the Marcellus Shale formation is also causing a bypass threat to the Company.[29]

Third, Mr. Moul testifies that residential sales are greatly influenced by the temperature conditions, and that residential sales have declined significantly over the past several years.[30]

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[29] Columbia Statement No. 10, page 5 line 22-page 6 line 4.

[30] Columbia Statement No. 10, page 6, lines 7-21.

Fourth, Mr. Moul notes that the Company does not currently have a revenue decoupling mechanism.

Fifth, Mr. Moul claims the Distribution System Improvement Charge (DSIC) has no effect on Columbia's cost of capital.[31]

Sixth, Mr. Moul discusses large volume customers, and the risks associated with that class of customers, including attrition, bypass, fuel switching, and competition.[32]

Finally, Mr. Moul claims that Columbia's proposed construction program will affect its risk profile.[33]

For all these reasons Mr. Moul believes that Columbia is riskier than the barometer group, and believes this should be taken into consideration when determining the rate of return.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE RISKS IN WESTERN PENNSYLVANIA?

A. Mr. Moul's claims regarding competition, bypass risk, and the Marcellus Shale are overstated. First, Columbia has no more risk than the other western Pennsylvania NGDCs such as Equitable and Peoples. Mr. Moul was also unable to identify any instances where the Commission has given

[31] Columbia Statement No. 10, page 7, starting on line 15.

[32] Columbia Statement No. 10, page 8.

[33] Columbia Statement No. 10, page 9.

western Pennsylvanian gas companies extra rate of return points based on competition and bypass risk.[34] The Commission has also launched a generic investigation into gas-on-gas competition at Docket No. I-2012-2320323. This investigation may determine whether the competition should be permitted to continue.

Further, Mr. Moul's concerns regarding the Marcellus Shale bypass risk have no support. In response to I&E-RR-55 and I&E-RR-56,[35] Columbia stated that it has only lost 5 industrial customers since the last base rate case in 2010. Columbia further stated that these 5 were lost due to a plant closing, not due to bypass of distribution. These risks are overstated by Mr. Moul.

Q. WHAT COMMENTS DO YOU HAVE REGARDING RESIDENTIAL CUSTOMER RISKS?

A. Mr. Moul cites temperature changes as a risk, however all NGDCs have this risk. Furthermore, for residential customers, both Columbia's current rate design and Columbia's proposed rate design have adjustments accounting for temperature changes. Columbia's current rate design uses a weather normalization adjustment in historic revenues, whereas Columbia's proposed rate design uses the revenue neutralization adjustment, which

[34] I&E Exhibit No. 1, Schedule No. 13; reply to I&E-RR-59-D.

[35] I&E Exhibit No. 1, Schedule No. 14; reply to I&E-RR-55 and I&E-RR-56

would capture the changes in revenue, including any decline in residential usage which can be attributable to weather. Mr. Moul also testifies that Columbia does not have a revenue decoupling mechanism, however in this case Columbia is proposing a mechanism similar to decoupling, which the Commission may approve. Again, these risks are overstated by Mr. Moul.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE DSIC?

A. Mr. Moul argues that the DSIC has no effect on risk because the barometer group companies have similar mechanisms. Notably, the Company indicated that it intends to file for its DSIC on January 2, 2013, for use in the first two quarters of 2013 before base rates go into effect.

The combination of both a FPFTY and a DSIC mechanism is seen as a positive by the credit rating agencies and investors because there will be a more timely collection of investments. Instead of investing and having to wait until the project is complete before receiving a return, the Company is able to collect a return of and on its investment for anticipated projects. This is a substantial change in the regulatory process, which reduces risk because not only is the Company receiving the return more timely, it is also essentially signaling to investors that these projects have been approved for rate recovery. This approval reduces the risk that the Company might invest in something that the Commission will not allow the Company to recover for, which in turn reduces the risk of investors not receiving a return. As discussed in Mr. Hubert's testimony, I&E Statement No. 3, the approval accounts for $145,926,196 of rate base and $21,942,430 of revenues of the filed increase in this case. These are risk reducers Mr. Moul fails to account for in his analysis.

Q. WHAT COMMENTS DO YOU HAVE REGARDING LARGE INDUSTRIAL AND COMMERCIAL CUSTOMERS RISKS?

A. Mr. Moul argues that the Company's risk profile is influenced by these customers through the risk of attrition, bypass, fuel switching, and competition.[36]

First, all gas companies are at risk of fuel switching, therefore there is no additional risk to Columbia.

Second, in response to I&E-RR-55-D and I&E-RR-56-D, the Company stated it has lost 5 and gained 6 large industrial and commercial customers since the last base rate case in 2010. This resulted in a volume loss of approximately 746,000 dekatherms, and a volume gain of 741,000 dekatherms. Further, as stated previously, those customers were lost due to a plant closing, and not bypass or competition.

Third, the 5 largest industrial and commercial customers account for less than 0.10% of total revenues on a per customer basis.[37] Furthermore,

[36] Columbia Statement No. 10, page 8.

[37] Reply to I&E-RR-3-D.

the top 10 industrial and commercial customers overall account for only 0.92% of total revenues.[38] Therefore, the loss of these large industrial and commercial customers does not account for a large percentage of revenues.

Finally, the Gas-on-Gas competition is not a new development for Columbia's service territory, and NGDCs in western Pennsylvania have not been granted a higher return for this competition in the past.

Q. PLEASE SUMMARIZE YOUR COMMENTS REGARDING COLUMBIA'S NATURAL GAS RISK.

A. A review of the information associated with Mr. Moul's claims of risk shows that Columbia is not as risky as Mr. Moul would lead one to believe. The western part of Pennsylvania is not new to competition, risk mitigation adjustments in place for residential customer usage, and the support for the large industrial and commercial customers' risk leads to the opposite conclusion of that of Mr. Moul. Furthermore, Mr. Moul was unable to provide any instances in which return on equity was increased for these risks.

[38] Reply to I&E-RR-5-D.

FUNDAMENTAL RISK ANALYSIS

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING FINANCIAL DATA COMPARISON FOR COLUMBIA AND THE GAS GROUP.

A. Mr. Moul discusses several categories of risk including credit quality, size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas.[39] Mr. Moul compares the Company, the Gas Group and the S&P Public Utilities using these categories. Mr. Moul concludes that, "Columbia of Pennsylvania's (CPA) risk is higher than the Gas Group" and that, "[o]n balance, the cost of equity measured with the Gas Group data will provide an understatement of the Company's cost of equity." (Columbia Statement No. 10, page 15, lines 2 and 5-7)

Q. WHAT COMMENTS DOES MR. MOUL HAVE REGARDING CREDIT QUALITY?

A. Mr. Moul describes Columbia's parent company NiSource's credit worthiness.[40] The table below summarizes Mr. Moul's comparisons of credit qualities of the different groups he analyzes:

[39] Columbia Statement No. 10, pages 10-14.

[40] Columbia Statement No. 10, page 11

Company	Moody's Rating	S&P Rating
NiSource	Baa3	BBB-
Gas Group	A3	A
S&P Public Utilities	Baa1	BBB+

Mr. Moul concludes that the bond rating of NiSource, the Company's ultimate parent, is well below that of the Gas Group, which indicates higher credit quality risk.[41]

Q. DO YOU AGREE WITH MR. MOUL'S STATEMENTS REGARDING COLUMBIA'S CREDIT QUALITY?

A. No. First, the credit quality of NiSource is not related in this case to the credit quality of Columbia. This is because NiSource has been evaluated by both Moody's and S&P as a collective of its various subsidiaries including Columbia Energy Group (CEG), Northern Indiana Public Service Co. (NIPSCO), and Bay State Gas Co. Further, S&P states, "NiSource is involved in regulated natural gas distribution (about 40% of consolidated operating income), gas transmission and storage (about 40%), and vertically integrated electric operations (about 20%)."[42] S&P continues, "The stand-alone financial profiles of NiSource's utility subsidiaries are much stronger than the consolidated financial profile, where substantial

[41] Columbia Statement No. 10, page 15, lines 3-4.

[42] Columbia Standard Data Requests, Question No. Gas-ROR-004, Attachment B, page 2 of 3.

acquisition-related debt is held." On page 3, S&P states "NiSource's liquidity position benefits from its ability to absorb high-impact, low-probability events with limited need for refinancing...it has above average access to the capital markets...we view the utility sector as having above average access to the capital markets, even during very challenging market conditions." These statements support a conclusion that Columbia Gas of Pennsylvania, Inc. does not have higher credit quality risk than the Gas Group.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S TESTIMONY ABOUT SIZE?

A. Mr. Moul discusses size in his direct testimony. I have previously discussed why size is not a factor in this proceeding on pages 54-58 of this testimony.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S TESTIMONY ABOUT RETURN ON BOOK EQUITY?

A. Mr. Moul testifies that Columbia has higher earnings variability than the Gas Group.[43] Mr. Moul states that Columbia's coefficient of variation was

[43] Columbia Statement No. 10, page 13

0.196, while the Gas Group's average coefficient of variation was 0.063. There are two problems with this analysis.

First, the Gas Group's range of coefficient of variation was 0.0793 – 0.4275. There are also 3 companies which have higher coefficients than Columbia (AGL, ATMOS, and NJR).

Company	**2011**	**2010**	**2009**	**2008**	**2007**	**Average**	**STDEV**	**CoV**
AGL	6.3%	12.1%	12.1%	12.5%	12.7%	11.1%	2.72%	0.244
ATMOS	8.7%	9.3%	8.9%	8.9%	9.2%	9.0%	0.24%	0.272
LG	11.3%	10.1%	12.8%	12.7%	12..1%	11.8%	1.12%	0.095
NJR	13.3%	16.3%	3.8%	16.6%	11.1%	12.2%	5.22%	0.428
NWN	9.0%	10.6%	11.6%	11.3%	12.4%	11.0%	1.28%	0.117
PNY	11.6%	15.0%	13.5%	12.5%	11.9%	12.9%	1.38%	0.107
SJI	14.4%	11.7%	10.6%	15.0%	13.3%	13.0%	1.84%	0.141
SWX	9.1%	8.9%	8.0%	5.9%	8.7%	8.1%	1.31%	0.161
WGL	9.9%	9.7%	11.2%	11.5%	11.3%	10.7%	0.85%	0.079
Average						11.1%	1.66%	0.183
STDEV						2.2%		

Second, as demonstrated by the range of coefficients above, Mr. Moul's Gas Group coefficient of 0.063 (2.2%/11.1%) is misleading. Mr. Moul calculated this coefficient by averaging the average returns on equity (11.1%), and using the standard deviation of the average returns (2.2%). This coefficient shows the variability in the average returns of all companies, but does not account for each company's own variations in equity returns. This is demonstrated by the fact that the 0.063 is lower than any of the company's individual coefficients. Therefore, the 0.063 is not comparable to Columbia's variability of its own returns.

To calculate a number comparable to Columbia's 0.196, the coefficients of variation must be calculated for each company, as provided in the table above, and then averaged. This calculation results in a coefficient of variation for Mr. Moul's Gas Group of 0.183. Therefore, Columbia is actually within the range of coefficients and is not materially different from the average coefficient of the Gas Group. A risk adjustment is not warranted in this case due to Mr. Moul's misleading calculation.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S STATEMENTS ABOUT COVERAGE?

A. Mr. Moul testifies that the Gas Group had higher coverage ratios than Columbia.[44] Mr. Moul states that the interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 3.52 times for Columbia, and 4.33 times for the Gas Group. However, the Gas Group's range was 2.69 times – 6.25 times. The interest coverage of Columbia is within this stated range, and therefore, is in line with the Gas Group's risk.

[44] Columbia Statement No. 10, page 13, lines 21-23.

Q. WHAT COMMENTS DO YOU HAVE REGARDING INTERNALLY GENERATED FUNDS?

A. Mr. Moul testifies that Columbia's percentage of internally generated funds (IGF) divided by construction has lagged behind that of the Gas Group's, 83.7% for Columbia compared to 106% for the Gas Group.[45] However, a review of this data reveals that there are 4 companies in the Gas Group that have percentages between 85% - 98%.

Also, there are two components to this calculation; internally generated funds and construction. Both components can shift to cause an increase or decrease to this percentage. For example, if a company has internally generated funds equal to $10 and construction of $5, the percentage calculates to 2% (10/5). If the company then decreases its internally generated funds to $5, the new percentage is 1% (5/5). If the company instead increases the construction budget to $10, the new percentage is also 1% (10/10). Therefore, it is not only a decrease in internally generated funds which may cause the percentage to drop, but also an increase in construction (ie. Columbia's need to replace risky pipe).

Since this factor can be a result of increased construction, and Columbia has needed to replace risky pipe in recent years, this factor does

[45] Columbia Statement No. 10, page 14, lines 9-14.

not appropriately describe Columbia's risk and does not support the need for a risk adjustment.

Q. WHAT COMMENTS DOES MR. MOUL HAVE REGARDING COLUMBIA'S RISK COMPARED TO THE GAS GROUP?

A. Mr. Moul testifies that based on the Company's smaller size, variable equity returns, and lower IGF to construction, Columbia's risk is higher than the Gas Group.[46]

Q. DO YOU AGREE WITH MR. MOUL'S COMMENTS REGARDING COLUMBIA'S RISK COMPARED TO THE GAS GROUP?

A. No. I have addressed how Mr. Moul incorrectly calculates the variability in equity returns, showing Columbia to be in line with the Gas Group; I have addressed how size is not a factor for utilities; I have addressed how a lower IGF to construction is not an appropriate valuation of risk; and, I have shown that NiSource, and therefore Columbia, has above average access to the capital markets, especially in times of recessions. Through my review of Mr. Moul's analysis, Columbia's risk is in line with the Gas Group, and no risk adjustment is warranted or supported.

[46] Columbia Statement No. 10, page 15, lines 1-2.

MANAGEMENT RECOGNITION POINTS

Q. WHAT IS THE COMPANY'S REQUEST REGARDING MANAGEMENT RECOGNITION POINTS?

A. Mr. Moul proposes to add 10 basis points to his recommended cost of equity in recognition of the Company's claimed superior performance of its management.[47]

Mr. Kempic provides areas of management performance given in support of the 10 basis point request. These areas include Columbia's customer satisfaction, low income and customer programs, distribution system, and automated meter reading devices.

Q. DO YOU AGREE WITH THE 10 BASIS POINT ADDITION TO THE RATE OF RETURN PROPOSED BY MR. MOUL?

A. No. The 10 basis point addition to the rate of return is unnecessary.

Q. PLEASE EXPLAIN.

A. There are several reasons Mr. Kempic has given for the 10 basis point addition to rate of return, however I&E witnesses demonstrate that the Company's performance is average.

[47] Columbia Statement No. 10, page 4, lines 21-23.

Q. WHAT COMMENTS DOES I&E HAVE REGARDING COLUMBIA'S CUSTOMER SATISFACTION?

A. Ms. Maurer discusses the customer satisfaction reports in I&E Statement No. 4. After reviewing the Commission's 2011 Quality of Service Benchmarking Report (Benchmarking Report) and the Utility Consumer Activities Report and Evaluation, Ms. Maurer concludes that Columbia is at best average when compared to the industry. It was also determined that Columbia is below the industry average in 41% (11 of the 27) of the total metrics used in the Benchmarking Report.

Also, Columbia's witness, Rachel Ford, notes that according to the 2011 J.D. Power survey results, Columbia's overall customer communication satisfaction scores decreased from 2010 to 2011 by 10 percent.[48]

This supports I&E's recommendation to disallow the management efficiency points in this case.

Q. WHAT COMMENTS DO YOU HAVE REGARDING COLUMBIA'S DISTRIBUTION SYSTEM IMPROVEMENTS?

A. Columbia requests efficiency points because it has replaced more pipe than other NGDCs, and began replacing pipe sooner than other companies.

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[48] Columbia Statement No. 18, page 4, lines 19-20.

However, as Mr. Giebel testifies in I&E Statement No. 7, Columbia accelerated its pipeline replacement and performed enhanced leak surveys because of poor performance in these areas that resulted in reportable incidents. Columbia entered into discussions with the Commission in 2007 to address these risks. These identified risks lead to the decision for Columbia's need to begin replacing pipe. Furthermore, Columbia is doing what is required by its Distribution Integrity Management Program (DIMP); this program is not optional. Columbia should not receive management efficiency points for adhering to requirements.

Q. ARE THERE ANY OTHER COMMENTS REGARDING COLUMBIA'S REQUEST FOR ADDITIONAL RETURN ON EQUITY POINTS?

A. Yes. In addition to the above reasons, Columbia should not receive extra return on equity points for management efficiency because it is already proposing to recover its claimed management incentive program through expenses, as Ms. Wilson testifies in I&E Statement No. 2. Moreover, as discussed by Ms. Wilson, my recommended return on equity recognizes the beneficial revenue impact of the FPFTY.

Q. PLEASE EXPLAIN.

A. Columbia is claiming its management incentive programs as expenses in this case. Therefore, ratepayers are already paying for management's "efficiency" through rates. To award management efficiency points through rate of return, while also allowing the Company's claim for this through expenses, charges ratepayers twice for the same "efficiency" claim.

Also, Columbia receives return dollars for efficiency by simply being efficient. When costs are cut or other efficiencies occur to reduce expenses, such as replacing leaky pipes, management thereby decreases expenses and increases net income (or return).

Additional management efficiency points are not necessary as Columbia is already being rewarded for efficiencies.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MANAGEMENT EFFICIENCY POINTS.

A. I recommend that the additional 10 basis points not be awarded in this case. As described above, Columbia has not proven that it has outstanding management. In fact, Columbia has simply proven it is average, and is doing what is necessary to provide safe and reliable service to its customers. Therefore, the additional 10 basis points proposed are not warranted.

MISCELLANEOUS

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARDS TO RETURN ON EQUITY?

A. Yes. Mr. Moul mentions a 2008 Gas Study, stating that allowed equity returns below the level required by investors may lessen a utility's ability to maintain and develop systems that are necessary to provide natural gas service efficiently. He further noted that returns below 10% would trigger broad disenchantment with Local Distribution Companies (LDC).[49]

Q. WHAT COMMENTS DO YOU HAVE REGARDING THIS 2008 GAS STUDY?

A. First, this study includes stale data as came out in 2008, which is prior to the Great Recession.[50] The Great Recession has had a significant impact on the capital markets and the returns investors are willing to accept.

Second, with new developments in the regulation of utilities, a lower return is necessary due to the lower risk of the company through the use of DSIC type mechanisms, a FPFTY where future projects are approved, and other alternative rate making designs. The study also indicates that when utilities operate in a regulatory environment with mutual trust and

[49] Columbia Statement No. 10, page 5, lines 1-7.

[50] Navigant Consulting (2008) "Regulatory Policy of Return on Equity, Review and Analysis of the Natural Gas Utility Sector", written for the American Gas Foundation.

collaborative development of comprehensive service and rate structures by the LDC and the regulator, this offsets many of the concerns that low allowed returns indicate an unfavorable regulatory environment.

This study also found that although the returns are lower, little impact of this has been seen, and that public markets for capital have still been accessible for LDCs.

This study's main focus is on the infrastructure of the utilities and the view that low returns will hurt the ability to attract capital to fund the infrastructure improvements. This report also discusses how revenue decoupling can provide revenue stabilization. When revenues are stable there is less risk. Since this report, risk reducers have been introduced such as DSIC and DSIC type mechanisms, FPFTY, and other alternative rate designs. It's logical to conclude that lower returns are attributable to these risk reducing mechanisms.

Mr. Moul's claim that a return lower than 10% would trigger broad disenchantment with LDC investment is not supported in the current market, and therefore should be disregarded.

OVERALL RATE OF RETURN

Q. WHAT IS THE COMPANY'S PROPOSED OVERALL RATE OF RETURN?

A. The Company's proposed overall rate of return is 8.52% (Columbia Exhibit 400, page 1 of 33, Schedule 1 [1 of 1]).

Q. WHAT IS I&E'S RECOMMENDED OVERALL RATE OF RETURN?

A. I&E Exhibit No. 1, Schedule No. 1, page 1 of 2, shows the calculation of an appropriate overall rate of return for Columbia Gas of Pennsylvania, Inc. to be 7.00%.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

Emily Sears

Professional Experience

- **Commonwealth of Pennsylvania, Public Utility Commission**
  Fixed Utility Financial Analyst
  Bureau of Investigation and Enforcement
  May 2009 - Present

- **Commonwealth of Pennsylvania, Public Utility Commission**
  Fixed Utility Financial Analyst
  Bureau of Fixed Utility Services
  April 2008 – May 2009

- **Nationwide Insurance Company**
  Personal Lines Underwriting Screener
  October 2004 – May 2007

Education

- **University of Pittsburgh, College of Business Administration**
  Bachelors of Science in Business Administration
  Major – Finance
  August 2004

- **Society of Utility and Regulatory Financial Analysts**
  Certified Rate of Return Analyst
  June 2010

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

- Duquesne Light Company, Docket No. M-2009-2093217
- West Penn Power Company d/b/a Allegheny Power, Docket No. M-2009-2093218
- Duquesne Light Company, Docket No. M-2009-2123948
- West Penn Power Company d/b/a Allegheny Power, Docket No. M-2009-2123951

- Utilities, Inc. – Westgate, Docket No. R-2009-2117389
- Utilities, Inc. of Pennsylvania, Docket No. R-2009-2117402
- PECO Energy Company - Electric Division, Docket No. P-2009-2143607
- PECO Energy Company – Gas Division, Docket No. P-2009-2143588
- Philadelphia Gas Works, Docket No. R-2009-2139884
- York Water Company, Docket No. R-2010-2157140
- City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2010-2215623
- CMV Sewage, Inc., Docket No. R-2011-2218562
- Pennsylvania American Water Company, Docket No. R-2011-2232243
- UGI Penn Natural Gas, Docket No. R-2011-2238943
- Aqua Pennsylvania, Inc., Docket No. R-2011-2267958
- Equitable Gas Company, LLC, Docket No. R-2012-2287044
- PPL Electric Utilities Company, Docket No. R-2012-2290597
- City of Lancaster – Sewer Fund, Docket No. R-2012-2310366

I&E Statement No. 1-SR
Witness: Emily Sears

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

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Surrebuttal Testimony

of

Emily Sears

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Emily Sears. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME EMILY SEARS WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 1 AND THE SCHEDULES IN I&E EXHIBIT NO. 1?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made by the Columbia Gas of Pennsylvania, Inc. (Columbia or Company) witnesses Mr. Paul R. Moul and Mr. Mark R. Kempic in their rebuttal testimony regarding rate of return, including the cost of debt, the cost of common equity and the overall fair rate of return, which will be applied to the Company's rate base.

SUMMARY OF MR. MOUL'S TESTIMONY

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIOMNY REGARDING THE I&E DIRECT TESTIMONY.

A. Mr. Moul disputes my calculation of Columbia's cost of debt. Mr. Moul also argues that there are six items which create the difference between his and my return values. These six items include the DCF growth rate, inclusion of a leverage adjustment, use of methods other than the DCF, the Company's claimed higher risk, differences in the proxy group, and a cost of equity adder for the claimed management efficiency.

COST OF DEBT

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING COLUMBIA'S DEBT COST RATE.

A. Mr. Moul has recalculated Columbia's cost rate of debt, changing the long-term debt cost rate to 5.81% from 5.80%. Mr. Moul also re-evaluated the cost rate of short term debt to 1.85%. These two changes result in no change to the requested cost rate of total debt.[1]

[1] Columbia Statement No. 110-R, pages 7-8.

Q. WHAT IS MR. MOUL'S SUPPORT FOR THESE CHANGES?

A. Mr. Moul claims he uses the Company's cost of debt as calculated in accordance with the securities certificate obtained from the Commission.[2] He further claims that Columbia would not have high credit quality on its own.[3] Mr. Moul also states that Columbia's affiliation with NiSource provides many benefits.

Q. DO YOU AGREE WITH MR. MOUL'S UPDATED DEBT COST ANALYSIS?

A. No. Mr. Moul claims there are benefits associated with NiSource, yet provides debt cost rates 100 basis points higher than current rates listed for Baa rated Public Utilities in the Mergent Bond Record. This higher cost is not a benefit.

Mr. Moul also claims Columbia would not have high credit quality on its own. Yet, as quoted in my direct testimony, S&P states, "The stand-alone financial profiles of NiSource's utility subsidiaries are much stronger than the consolidated financial profile."[4] This statement directly refutes Mr. Moul's claim.

Mr. Moul further claims that the Company's cost of debt is calculated in accordance with the securities certificate obtained from the Commission. In the Order approving the securities certificate, the Commission determined that the interest rate should be calculated by using the interest rate of the corresponding

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[2] Columbia Statement No. 110-R, page 7, lines 19-21.

[3] Columbia Statement No. 110-R, page 8, lines 2-3.

[4] I&E Statement No. 1, page 65, lines 16-17.

applicable Treasury yield (as reported in Federal Reserve Statistical Release (FRSR), H.15 Selected Interest Rates (Daily)) effective on the date a new note is issued, plus a yield spread on the corresponding maturities for companies with a credit risk profile equivalent to that of NiSource Finance Corp. (as reported by Reuters Corporate Spreads) effected on the date the new note is issued.[5]

I have used the above criteria to determine approximately what this rate would have been on November 28, 2012. The interest rate in the FRSR was 2.79% on November 28, 2012. I do not have access to historical Reuters information as a subscription is needed, however, the current spread for a utility with a BBB-/Baa3 rating as of January 29, 2013, is 132, or 1.32%. When these two percentages are added, the result is 4.01%.[6] This is 1.25%[7] lower than Columbia's claimed issued rate. Also, using information as of January 29, 2013, the FRSR for January 15, 2013, was 3.14% plus the Reuters spread of 1.32%, resulting in a current interest rate of 4.46%. This current interest rate is still 80 basis points lower than Columbia's claimed issued rate.

Therefore, I continue to support my recommendation of a 5.64% cost rate of long-term debt and a 1.60% cost rate of short term debt.

[5] Securities certificate for Columbia Gas of Pennsylvania, Inc. at Docket No. S-2012-2282635, page 2, Order entered March 1, 2012.

[6] 2.79% + 1.32% = 4.01%

[7] 5.26% - 4.01% = 1.25%

PROXY (BAROMETER) GROUP

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR PROXY GROUP.

A. Mr. Moul claims that the "percentage of revenue" requirement is not appropriate and that percentage of gas assets to total assets and percentage of gas income to total income are more appropriate.[8]

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS?

A. No. Revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If under 50% of revenues come from the regulated gas business sector, the companies are not comparable to the subject utility as they do not provide the same level of regulated business.

Assets are accounted for at the cost minus depreciation. This means that assets can be at different percentages at different times, based upon the age of the asset. A utility can have most of its assets depreciated, but still do more business as a utility than as another business. There also is a difference due to the amount of capital needed to run a certain business. For example a company may need only a small amount of assets to produce a large level of cash flow. Or vice versa, for example, utilities with all new equipment, a company may need a large level of

[8] Columbia Statement No. 110-R, page 11, lines 15-21.

assets to produce a small level of cash flow. Therefore, "gas assets to total assets" is not an appropriate criterion as it could be misleading.

Finally, a comparison of gas income to total income is not appropriate because income represents simply the ability to control costs and manage finances, not the business activity that is generated by a business line.

Therefore, revenue is an appropriate criterion, and as Mr. Moul has corroborated,[9] both South Jersey Industries and WGL Holdings have an insufficient amount of regulated utility revenues to be comparable to Columbia.

<u>DISCOUNTED CASH FLOW (DCF)</u>

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. Moul agrees that the results of the DCF analysis should be given considerable weight.[10] However, Mr. Moul argues that he does not agree with my results and therefore disaggregates my results. Mr. Moul then adds his personal leverage adjustment and ex-dividend adjustment. Mr. Moul then incorrectly assesses my dividend yield, and growth rate. Finally, Mr. Moul recalculates a DCF based upon his invalid analysis.

[9] Columbia Statement No. 110-R, page 12.

[10] Columbia Statement No. 110-R, page 12, lines 13-14.

Q. MR. MOUL DISAGGREGATES YOUR RESULTS, DO YOU HAVE ANY COMMENTS REGARDING THIS APPROACH BY MR. MOUL?

A. Yes. This approach is Mr. Moul's personal approach, one which I do not advocate. It is inappropriate to remove a company based solely upon its results, as this can create a bias. For example, if one company's results are considered to be "unfit" in this proceeding, and later the same company's results are determined to be "fit" due to the results, this is a bias. However, if one company's results are removed due to the company not fitting the barometer group criteria, then that is not a bias as it is not based upon a desired result.

This bias is demonstrated by Mr. Moul as he has removed AGL Resources, Laclede Group, and New Jersey Resources, claiming they are "totally unrealistic" for Mr. Moul.[11]

To prove my point above, in the most recent base rate case of People's Natural Gas Company at Docket No. R-2012-2285985, Mr. Moul included Laclede Group Inc. in his barometer group, which had a return on equity that was 575 basis points higher than his average. This inclusion created an upward bias. Mr. Moul appears to manipulate the companies included in his barometer groups based upon results in each case, creating bias. Mr. Moul's new analysis serves only to inflate his results by removing low results and including high results. My analysis, however, does not create a bias as the selection of companies for my

[11] Columbia Statement No. 110-R, page 13, line 15.

barometer group it is not based upon results, but rather based upon companies that have similar risk to that of the company. Mr. Moul's introduction of this bias is inappropriate as it serves only to inflate his calculated return in this case.

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING HIS EX-DIVIDEND ADJUSTMENT.

A. Mr. Moul claims there has been extensive research on the impact of the ex-dividend on stock prices. He further claims that the SEC gives significance to the ex-dividend adjustment. Mr. Moul claims that many financial publications provide ex-dividend adjusted yields. Finally, Mr. Moul claims my dividend yield calculation is erroneous.[12]

Q. DO YOU AGREE WITH MR. MOUL'S CLAIMS ABOUT THE EX-DIVIDEND ADJUSTMENT?

A. No. Mr. Moul is confusing the term ex-dividend *date* with ex-dividend *adjustment*. These are two different concepts. I continue to support my direct testimony stating that the ex-dividend adjustment is inappropriate and unnecessary.[13] Mr. Moul has failed to provide any evidence in terms of academic support, investor use, or financial publications, in which the dividend yield is adjusted for the ex-dividend date.

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[12] Columbia Statement No. 110-R, pages 14-15.

[13] I&E Statement No. 1, pages 42-43.

Q. IS THERE ACADEMIC SUPPORT FOR THE EX-DIVIDEND ADJUSTMENT?

A. No. Mr. Moul has provided voluminous information explaining the ex-dividend *date*. This information simply explains that it is the date at which the stock price is being reduced approximately by the amount of the dividend. However, Mr. Moul has failed to provide academic evidence showing that any type of *adjustment* is made to the dividend yield for this occurrence.

Q. HAS MR. MOUL PROVIDED ANY EVIDENCE WHICH DEMONSTRATES THAT INVESTORS MAKE THIS ADJUSTMENT?

A. No. Mr. Moul uses a statement by the SEC to support his claim. I have attached the full article in I&E Exhibit No. 1-SR, Schedule No. 1. Mr. Moul uses only one paragraph of the statement to support his claim. In fact, the article does not support Mr. Moul's claim, but rather explains only that the ex-dividend *date* is important to investors in determining when they are entitled to stock and cash dividends based upon the date they bought the stock. Long-term stock holders generally do not run into a problem with ex-dividend dates, as they hold their stock through price cycles. Ex-dividend dates are relevant when an investor wants to exit ownership of a stock, but would like to receive the dividend first. Mr. Moul has failed to provide any evidence suggesting that investors make an *adjustment* to the dividend yield based on this ex-dividend date.

Q. DO ANY FINANCIAL PUBLICATIONS PUBLISH THE EX-DIVIDEND ADJUSTMENT?

A. No. As I previously testified, Mr. Moul is confusing the terms. The ex-dividend *date* is published in many financial publications. However, any specific *adjustment* made to the dividend yield based on this date is not published in any financial publication that I am aware of, including those listed by Mr. Moul. Mr. Moul also opines that the "x" listed in the Wall Street Journal signifies the lack of pricing change related to the dividend.[14] The "x" simply signifies that it is the "ex-dividend *date*." The x does not signify any *adjustment* being made to the dividend yield, as Mr. Moul proposes. Therefore, Mr. Moul has not supported his claim that financial publications support this adjustment.

Q. DO YOU AGREE WITH MR. MOUL THAT YOUR DIVIDEND YIELD IS ERRONEOUS?

A. No. Mr. Moul has made several improper assumptions and incorrect calculations when making this statement. Mr. Moul claims that I have not made any adjustments to the dividend.[15] As I have testified I have used the formula $k = D_1/P_0 + g$.[16] By using D_1, meaning using the future dividend listed in Value Line,

[14] Columbia Statement No. 110-R, page 15, lines 15-16.

[15] Columbia Statement No. 110-R, page 15, lines 19-23.

[16] I&E Statement No. 1, page 10.

rather than D_0 (the current dividend), there is no need to adjust the dividend by half the growth rate, and it would be erroneous to do so.

The other mistake Mr. Moul has made is his quoted forward-looking dividend formula $D_{0/}P_0$ (1+.5g). This formula would require one to take the current dividend divided by the current price and then multiply by one plus half the growth rate. It would be inappropriate to take the dividend yield Mr. Moul states (D_0/P_0) and increase it, as we are looking for the future dividend (D_1) over the current price (P_0). Increasing the dividend yield would result in the future dividend over the future price (D_1/P_1). Rather, the correct formula to create a forward looking dividend when one is not available simply reads D_0(1+.05g). The result is D_1, which could then be divided by P_0.

Therefore, any adjustment to my dividend yield by Mr. Moul must be rejected.

GROWTH RATE

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR GROWTH RATE AND LOG-LINEAR PROCESS.

A. Mr. Moul removes only the negative growth rate for AGL Resources, citing that it is not reflective of the positive growth that investors expect. Mr. Moul also claims analysts' estimates are not biased. Mr. Moul inputs further bias in the growth rate by going to the higher end of his range of growth rates based upon his inadequate analysis of my statement regarding the inflection point. Mr. Moul then recalculates my DCF using his own data, removing relevant data, and including his personal leverage adjustment to determine his own adjusted DCF.[17]

Q. PLEASE COMMENT ON MR. MOUL'S REMOVAL OF YAHOO! FINANCE'S GROWTH RATE FOR AGL RESOURCES.

A. The removal of this growth rate is inappropriate for the same reason the removal of AGL Resources, Laclede Group, and New Jersey Resources is inappropriate. It would create an upward bias based upon results.

Q. DO YOU AGREE THAT ANALYSTS ESTIMATES ARE NOT BIASED BECAUSE YOU DID NOT ADJUST FOR THIS?

A. No. As indicated in my direct testimony,[18] I typically use the Log-Linear regression analysis to correct for any bias in analysts' estimates. However, in this case, due to the inflection point, historical growth is not indicative of future growth. I currently do not know of any other way to remove this bias, therefore I have used the analysts' estimates. However, I would not use the upper end of the analysts' range as Mr. Moul has done, as this further enhances the upward bias.

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[17] Columbia Statement No. 110-R, pages 16-18.

[18] I&E Statement No. 1, pages 27-31.

Q. DO YOU AGREE WITH MR. MOUL'S RE-CALCULATION OF YOUR DCF?

A. No. Mr. Moul has calculated an erroneous dividend yield, and included an inappropriate dividend yield adjustment. Mr. Moul has also calculated an upwardly biased growth rate. Mr. Moul further included an inappropriate leverage adjustment as discussed in my direct testimony, I&E Statement No. 1.[19] I continue to support my DCF equity cost rate of 8.51%.

LEVERAGE (MARKET-TO-BOOK) ADJUSTMENT

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING HIS LEVERAGE ADJUSTMENT.

A. Mr. Moul states that the credit rating agencies are not concerned with the cost of equity, nor how it is applied in the weighted average cost of capital in the rate-setting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of interest and principal by utilities. Mr. Moul states that the Blue Mountain case occurred during different economic conditions than those present today. Mr. Moul opines that the leverage adjustment rejected in the City of Lancaster decision, Docket No. R-2010-2179103 (Order entered July 14, 2011), is different than the leverage adjustment he proposes in this case. Mr. Moul inaccurately believes the Commission did not

[19] I&E Statement No. 1, pages 43-53.

repudiate his adjustment in Aqua, and claims the Metropolitan Edison case is distinguishable. Mr. Moul suggests that he has used the academic literature and extended it into the rate-setting process. Mr. Moul believes that his leverage adjustment is routinely discussed in the academic literature. Mr. Moul believes I have offered no substantiation for the statement that Dr. Morin's text is not peer reviewed, nor any evidence that the book has any deficiencies. Mr. Moul argues that it is the future cash flows that investors expect to realize that determines the price they are willing to pay for a share of common equity. Finally, Mr. Moul testifies that his "ku" factor is merely an iteration.[20]

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S COMMENTS CONCERNING CREDIT RATING AGENCIES?

A. Mr. Moul has supported the I&E argument that the leverage adjustment is not needed by stating that the credit rating agencies are only concerned with the timely payment of interest and principle by utilities (i.e. its financial risk).[21] Mr. Moul further contends that the book value of debt has nothing to do with his leverage adjustment. However, Mr. Moul supports his leverage adjustment by stating the Company has more book leverage than market leverage, which means it has more book value debt than market value debt. By changing the equity ratio, Mr. Moul is also changing the debt ratio since the percentage of debt plus the percentage of

[20] Columbia Statement No. 110-R, pages 26-30.

[21] Columbia Statement No. 110-R, page 26, lines 8-10.

equity must equal one hundred percent. However, in both cases, book value and market value, the actual amount of debt does not change. Therefore, there is no change in the amount of leverage. Since there is no change in the amount of debt, a leverage adjustment is not needed.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE RELEVANCE OF THE BLUE MOUNTAIN CASE TO THIS PROCEEDING?

A. Mr. Moul provided direct testimony in the Blue Mountain case, Blue Mountain Consolidated Water Company Statement No. 2, Docket No. R-781000686. On page 9, lines 12-15, Mr. Moul states that a multiple (above the book value of the stock) of 1.25 to 1 is desirable to maintain the financial integrity of presently invested equity and to attract future capital on a reasonable basis. On page 20, lines 3-5, he states that the common stock of the barometer group sold on average at only 85% of book value, and the group average was never above book value.

The above statements show that Mr. Moul advocated in the Blue Mountain case for a higher rate of return, to obtain market to book ratios above 1. However, Mr. Moul did not provide a leverage adjustment formula, which he has used in this case. If he had used his leverage adjustment, it could have lowered the recommended return on equity, due to less "book leverage", or market to book below 1. The Blue Mountain case has been used to show that Mr. Moul's recommendations are inconsistent. Finally, Mr. Moul has not explained which economic conditions at the time of the Blue Mountain case would void the use of his leverage adjustment formula.

Q. PLEASE COMMENT ON MR. MOUL'S TESTIMONY REGARDING THE MENTION OF THE METROPOLITAN EDISON CASE IN YOUR DIRECT TESTIMONY.

A. Mr. Moul claims that the MetEd case was distinguishable[22], but has not mentioned how. Therefore, my direct testimony regarding the Commission's rejection of the leverage adjustment is still relevant, as it states, "the Commission did not accept the company's financial risk increment related to the leverage difference between market capital structures and book value capital structures."

Q. PLEASE COMMENT ON MR. MOUL'S STATEMENT THAT THE COMMISSION DECLINED TO USE HIS LEVERAGE ADJUSTMENT IN AQUA, BUT DID NOT REPUDIATE THE ADJUSTMENT.

A. If it was indeed the case that the market value financial risk differed from the book value financial risk, the Commission would have needed to use the leverage adjustment in arriving at their rate of return on equity, however, it did not. This supports the rejection of the adjustment in this case as well.

[22] Columbia Statement No. 110-R, page 27, lines 15-16.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE CITY OF LANCASTER DECISION?

A. Mr. Moul contends that the adjustments proposed in this case and in the Lancaster case are different because the formulas used are different.[23] However, the theory behind the adjustment and the reasons for its use are exactly the same. In both cases, it was advocated that a leverage adjustment was needed due to the difference between market value capital structure and book value capital structure. The Commission rejected this proposed adjustment; therefore, the decision of the City of Lancaster supports the rejection of a leverage adjustment in this case.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE LACK OF ACADEMIC LITERATURE SUPPORTING MR. MOUL'S ADJUSTMENT?

A. Mr. Moul testifies that financial leverage is referenced in the work of Modigliani and Miller and Hamada.[24] However, Mr. Moul has not disputed my direct testimony stating that his formula cannot be found in any literature, that he uses the referenced work in a way which was not advocated, and that the referenced literature does not account for financial risk. Therefore, the leverage adjustment should not be accepted.

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[23] Columbia Statement No. 110-R, page 28, lines 3-5.

[24] Columbia Statement No. 110-R, page 28, lines 13-14.

Q. WHAT COMMENTS DO YOU HAVE REGARDING DR. MORIN'S BOOK?

A. Dr. Morin's book is not peer reviewed. In the preface of New Regulatory Finance, page xix it states "Where views and opinions are expressed in the book, they are my own and do not reflect the views of Public Utilities Reports or Georgia State University. I assume responsibility for any errors." Also, peer reviewed documents provide a non-biased view on a subject matter by discussing all sides of an issue. While Dr. Morin may be knowledgeable, his book is not without bias. Further, as discussed in my direct testimony[25] the formula Mr. Moul uses from Dr. Morin's book has not been academically vetted, and therefore cannot be relied upon.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON MR. MOUL'S REBUTTAL REGARDING DR. MORIN'S BOOK?

A. Yes. Mr. Moul believes he has used the capital structure to estimate the cost of equity through his leverage adjustment, however the capital structure needed no adjustment to estimate the proper cost of equity.

[25] I&E Statement No. 1, pages 50-51.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S "KU" FACTOR?

A. Mr. Moul believes that his formula for solving for "ku" is performed by an iterative process. He also believes that I&E-RR-14-D refutes my direct testimony.[26] Rather, the data request he refers to, I&E-RR-14-D, shown in I&E Exhibit No. 1-SR, Schedule No. 2, actually supports my direct testimony by asking Mr. Moul to show how he solved for "ku". In his response, Mr. Moul simply shows that "ku", unlike the DCF, is already solved for on the right hand side of the equation before the iterative process even begins. Mr. Moul has not shown a formula with the "ku" term on one side of the equation, which is customary in mathematics when solving for a variable, nor has he disputed my direct testimony stating the same. Therefore, stating that his proposed leverage adjustment contains flaws related to the "ku" factor is accurate, and Mr. Moul's formula cannot be relied upon.

Q. PLEASE COMMENT ON MR. MOUL'S BELIEF THAT INVESTORS DO NOT BASE THEIR DECISIONS ON BOOK VALUE, BUT RATHER THE FUTURE CASH FLOWS THAT INVESTORS EXPECT TO REALIZE.

A. First, Mr. Moul is stating here that investors use the DCF (discounted cash flow) method to determine their required return, as future cash flow is the concept

[26] Columbia Statement No. 110-R, page 29, lines 10-17.

behind the DCF method. However, earlier in his testimony he argues that many methods must be used, and the DCF alone is not appropriate. Therefore, according to Mr. Moul, investors look at information other than simply future cash flows, e.g. book value.

Second, to say that an investor does not consider the book value listed in Value Line is to say investors do not use Value Line as a source.

Third, to say an investor is unconcerned with the book value debt (and therefore financial risk) of a utility is unsupported. Clearly an investor takes the financial risk of the utility into consideration when determining their required return.

Finally, market capitalization is not the same as market value capital structure. Market capitalization refers to the amount of shares outstanding multiplied by the current price, while market value capital structure refers to the current market debt cost over total equity and current market equity cost over total equity.

Therefore, Mr. Moul's contention that Value Line includes market capitalization data as support for his leverage adjustment adds no value.

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT.

A. Mr. Moul's claims regarding the credit rating agencies support the I&E position, the referenced cases show Mr. Moul's inconsistencies and the support of the rejection of the leverage adjustment, Dr. Morin's book shows bias and is not peer reviewed, Mr. Moul lacks academic support for this adjustment, and Mr. Moul's "ku" factor cannot be relied upon. For all these reasons the leverage adjustment should be rejected.

RISK

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING COLUMBIA'S RISK.

A. Mr. Moul argues that Columbia has higher risk than the barometer group by stating that the DSIC is already considered in my barometer group. Mr. Moul continues to observe that many other members of the barometer group have similar mechanisms. Mr. Moul then claims that Columbia has no weather mitigated rate design, and observes that Columbia has an overlapping service territory. Mr. Moul then claims that Columbia is faced with competitive threats unlike any of the companies in my gas barometer group.[27]

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S RISK ANALYSIS?

A. Mr. Moul claims that the Company has higher risk than my barometer group due to no weather mitigation and an overlapping service territory. Mr. Moul also

[27] Columbia Statement No. 110-R, pages 31-32.

claims that the DSIC is already factored into the barometer group, and will not offset the Company's higher risk. However, the ability for the Company to earn a return of and a return on its infrastructure between rate cases reduces the regulatory lag associated with the higher infrastructure replacements after the test year. Mr. Moul does not consider this risk reducer in his analysis of Columbia's overall risks. Rather, Mr. Moul disregards the DSIC and includes adders for his perceived increased risk of Columbia.

The competitive risk Mr. Moul refers to is much lower than Mr. Moul would lead one to believe. Mr. Moul has not refuted any of my direct testimony regarding Columbia's risk and return.

Finally, I have already shown that Columbia's risk is in line with the barometer group. Mr. Moul does not dispute the individual risk factors, rather only suggests Columbia's risk is higher than that of the barometer group.

Q. DOES MR. MOUL TAKE THE ADDITIONAL RISKS OF THE UNREGULATED PORTION OF THE BAROMETER GROUP INTO CONSIDERATION?

A. No. Mr. Moul fails to realize that the barometer group includes risks that Columbia does not face. The barometer group is simply a proxy for Columbia, and is as close to Columbia's risk as is publicly available. However, these companies are not 100% regulated as is Columbia. Rather, these companies have a mix of unregulated businesses which may increase its risk as compared to

Columbia. Therefore, while Columbia may have one risk that is slightly greater than the barometer group, the barometer group companies may have an offsetting risk.

CAPITAL ASSET PRICING MODEL

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR APPLICATION OF THE CAPM.

A. Mr. Moul believes I have used an understated risk-free rate of return, used incorrectly calculated historical market returns that do not reflect investor expected market returns, failed to use leverage adjusted betas, and failed to make a size adjustment.[28]

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR RISK-FREE RATE USED IN THE CAPM FORMULA.

A. Mr. Moul opines that I have used an understated risk-free rate of return. Mr. Moul continues to speculate that I incorrectly gave the same weight to the yield on the 10-year Treasury notes for the first quarter of 2010 as I do for the entire five year period 2012 to 2016. Mr. Moul claims that 2010-2012 is past and not useful in the forecast. Mr. Moul further claims that the rates in this proceeding will not become

[28] Columbia Statement No. 110-R, page 34, lines 4-7.

effective until 2013. Mr. Moul then incorrectly recalculates the risk-free rate to be 3.4%.[29]

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS OF YOUR RISK FREE RATE?

A. No. Regarding my calculation of a risk-free rate, the labels provided in I&E Exhibit No. 1, Schedule 9 were incorrect. The Exhibit should have started in 4Q 2012, not 2010, and continued through ending with the years 2014-2018.[30] However, while the labels were incorrect, the yields and analysis were correct.

As to Mr. Moul's new calculation, it is improper to give equal weight to each separate year from 2013 to 2017, as he proposes. The farther out into the future one forecasts, the less reliable the estimates become. To give the less reliable estimates equal weight would not be prudent. Therefore, it is more appropriate to weight the quarters and years as I have done in my direct testimony, and shown in I&E Exhibit No. 1, Schedule No. 9. In addition, the last quarter in 2012 and the first two quarters in 2013 are useful because 2012 provides one historical and accurate interest rate, and 2013 is necessary for continuity and completeness of information. Also, given that the further out one forecasts, the less reliable the information, using these time periods allows for a more accurate risk-free rate.

[29] Columbia Statement No. 110-R, page 34.

[30] See I&E Exhibit No. 1-SR, Schedule No. 3.

I also have updated my risk-free rate using the most recent information available to determine a risk-free rate of 2.28%.[31] Due to the similarity to the risk-free rate used in my direct testimony of 2.26%, I have not made any adjustments to the CAPM. I continue to support my direct testimony regarding the risk free rate.

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING YOUR CALCULATION OF THE TOTAL MARKET RETURN.

A. Mr. Moul mistakenly assumes that the I&E expected market return of 6.02% for the S&P 500 using historical data "cannot possibly be correct" given that I determined the DCF for the barometer group to be 8.51%. Mr. Moul then believes that because the S&P 500 has a beta of 1, it could not have a lower expected market return than the barometer group, which has a beta of 0.66. He further believes that it would be "inconceivable" that investors would expect returns of -0.25% and 2.92% for the 5 and 10 year periods. This leads Mr. Moul to believe that I have introduced a substantial downward bias in my analysis. Mr. Moul believes that the arithmetic return should be used instead of the geometric mean in determining an appropriate market return. Mr. Moul testifies that the geometric mean consists merely of a rate of return taken from two data points and cannot provide a reasonable representation of the market risk premium in the context of

[31] I&E Exhibit No. 1-SR, Schedule No. 3

the CAPM. Mr. Moul also opines that the expected equity risk premium should always be calculated using the arithmetic mean, citing Stocks, Bonds, Bills & Inflation: 1996 Yearbook, Ibbotson Associates, 1996, p.153-154. Mr. Moul then recalculates the I&E historic average to be 11.76%. Finally, Mr. Moul claims the market premium is unreliable.[32]

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S ASSUMPTIONS ABOUT YOUR HISTORIC MARKET RETURN?

A. Mr. Moul makes numerous errors in his testimony regarding my CAPM analysis. First, Mr. Moul erroneously compares the CAPM market premium to the DCF cost of equity return. These are two different numbers conceptually - one is a market premium, and the other is the final computed cost of equity. In order to compare the CAPM numbers to the 8.51% DCF return Mr. Moul cites, one must use the calculated CAPM range of 4.75% to 9.08%. This proper comparison shows that my analysis is accurate, and Mr. Moul's is illogical. Second, Mr. Moul mistakenly computes the CAPM market results using only the *historic* values of the market to conclude that my CAPM is too low, and then uses the *forecasted* values of the market to conclude that his re-calculated CAPM is more appropriate.[33] Mr. Moul's methods of comparison are inconsistent. Mr. Moul's analysis only serves to confirm that the CAPM can be manipulated to generate

[32] Columbia Statement No. 110-R, pages 35-38.

[33] Columbia Statement No. 110-R, page 37, lines 21-23.

different results, making it less reliable than the DCF, and that Mr. Moul's analysis is inaccurate.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. MOUL'S DISCUSSION ON BETA?

A. Yes. Mr. Moul's analysis of beta in his rebuttal testimony is incorrect. As described in my direct testimony, beta measures the price movement as compared to the overall market (e.g. volatility).[34] A beta of 1 means that a stock has the same volatility as that of the market. A beta of 0.675 means a stock has less volatility than that of the market. For example, if the S&P 500 moves down (beta of 1), the utility stock will not decrease at the same rate, as it has a beta of only 0.675. This means that in times of economic downturn, as we have experienced, it is only logical that the utilities would move downward less than the S&P 500, and therefore outperform the more volatile stocks, ie. the S&P 500. Therefore, Mr. Moul's conclusion that the S&P 500 having a beta of 1 should always have a higher return than that of stocks having a beta smaller than 1 is illogical. As seen in I&E Exhibit No. 1-SR, Schedule 4, the utilities outperform the S&P 500 in times of recession. Accordingly, my CAPM analysis, which Mr. Moul believes is "inconceivable", is appropriate given the current economic conditions.

[34] I&E Statement No. 1, pages 32-33.

Q. DO YOU AGREE WITH THE USE OF THE ARITHMETIC MEAN OVER THE GEOMETRIC MEAN, AS MR. MOUL SUGGESTS?

A. No. There are several reasons why this is inappropriate; including an outdated statement used by Mr. Moul, the existence of two different ways to calculate the geometric mean, and a demonstration of the shortcomings of applying the arithmetic mean in a regulatory setting.

Q. WHAT STATEMENT MADE BY MR. MOUL IS OUTDATED?

A. Mr. Moul's statement cited in the 1996 SBBI Yearbook is outdated. In the Ibbotson SBBI: 2012 Valuation Yearbook, Morningstar, 2012, p. 56, the statement, "The expected equity risk premium should always be calculated using the arithmetic mean", which is located under the heading "Arithmetic versus Geometric Means", has been removed, and should therefore be disregarded. Furthermore, the Ibbotson book states under the same heading, "The geometric average is more appropriate for reporting past performance, since it represents the compound average return" thereby confirming I&E's use of the geometric mean for the historic S&P 500 total market return.

Q. WHAT ARE THE TWO WAYS TO CALCULATE THE GEOMETRIC MEAN?

A. The two ways to calculate the geometric mean are: 1) by using the beginning and ending points, or 2) by using all points included in a set of data. I&E has included all data points in its calculation of the geometric mean.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE DEMONSTRATING THE SHORTCOMINGS OF APPLYING THE ARITHMETIC MEAN IN A REGULATORY SETTING?

A. Yes. Suppose a hypothetical investor has $100 to invest over a two-year period. The first year the investor earns a 100% return so that his ending wealth at the end of the period 1 is $200. The second year the investor has a -50% return (loses $100) so that his ending wealth at the end of period 2 is $100. It is quite clear that the investor has not earned a return since he ends the two year period with the same $100 that he started with. The calculated geometric return is 0% = ($100/$100)^$^{1/2}$, which shows the lack of increased wealth. However, the calculated arithmetic return is 25% = (100% - 50%)/2. This means an investor relying on the arithmetic mean would have expected to have an ending wealth of $125, but instead would only have an ending wealth of $100. This illustrates the inherent bias of using the arithmetic mean to calculate period results. As a result; it is quite clear that the use of the arithmetic mean for cost of capital purposes in a regulatory setting will produce biased results and that the geometric mean is more accurate and appropriate.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S ANALYSIS OF THE MARKET PREMIUM?

A. Mr. Moul believes that investor expectations include a market premium that exceeds substantially the historic calculations. Mr. Moul has not shown any evidence supporting his assumption. In a healthy economic environment one could expect increasing returns. However, in 2008 the market experienced the worst market it has seen since the Great Depression. To expect returns higher than what occurred before the recession in the current economy would be unrealistic.

SIZE

Q. PLEASE SUMMARIZE MR. MOUL'S TESTIMONY REGARDING SIZE.

A. Mr. Moul discusses his views on Dr. Wong's article provided in I&E Exhibit No. 1, Schedule No. 12. Mr. Moul references articles from the Journal of Finance, "The Cross-Section of Expected Stock Returns", and from Dr. Thomas Zepp, "Utility stocks and the size effect: revisited."

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE REFERENCED ARTICLES?

A. "The Cross-Section of Expected Stock Returns" is not specific to the utility industry and therefore is irrelevant to this case. Additionally, the referenced article from Dr. Zepp does not re-create Dr. Wong's study, it simply speculates on other possible reasons for her results and references the results of two other studies. The first study, completed by CPUC Staff in 1991, is not included in the article, and therefore Dr. Zepp's opinions cannot be properly evaluated. The second study examines the effects of size on four water utility companies only. This article does not contain enough credible evidence to refute Dr. Wong's findings. Further, Mr. Moul has not provided any evidence to support his claim that changes in the utility industry have affected Dr. Wong's study. I continue to support Dr. Wong's study showing that size is not a factor in the utility industry, and that no size adjustment is warranted.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING SIZE?

A. Yes. Mr. Moul has not disputed my direct testimony stating that the technical literature of SBBI[35] suffers from the January effect and is unpredictable.

[35] Stocks Bonds Bills and Inflation yearbook provides variables for estimating the cost of capital.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. MOUL'S SIZE ADJUSMENT?

A. Therefore, I continue to recommend that his use of the 1.14% size adjustment should not be employed in calculating the CAPM.

Q. MR. MOUL HAS RECALCULATED YOUR CAPM RESULTS. DO YOU HAVE ANY COMMENTS?

A. Yes. Mr. Moul's recalculation is incorrect for several reasons. First, Mr. Moul used a risk-free rate which, as discussed above, is inaccurate. Second, Mr. Moul used leveraged betas. However, Mr. Moul has not refuted my direct testimony regarding leveraged betas, and therefore leveraged betas should not be used in any recalculation of my CAPM. Third, Mr. Moul's size adjustment is unnecessary, as stated in my both my direct testimony and above. Because of these factors, a recalculation of the I&E CAPM is imprudent; and any recalculation provided by Mr. Moul of the I&E CAPM is unreliable and unnecessary.

RISK PREMIUM

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE RISK PREMIUM METHOD.

A. Mr. Moul opines that the Risk Premium approach is an approach which provides a direct and complete reflection of a utility's risk and return. Further, Mr. Moul's claims that my statement that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation.[36]

Q. PLEASE COMMENT ON THE INDIRECT MEASURE OF THE RP METHOD VERSUS THE MORE DIRECT MEASURE OF THE DCF METHOD.

A. Mr. Moul makes a claim that my statement, "the Risk Premium method does not measure the current cost of equity as directly as the DCF", is without foundation. However, he has not provided evidence to support his speculation. In my direct testimony, I have clearly testified how the two measures are different.[37] One such argument is that the RP method determines the rate of return on common equity indirectly by observing the cost of debt, and adding to it an equity risk premium. Mr. Moul supports this statement by stating that the RP method uses the company's own borrowing rate, or in other words its own debt, and adds a risk premium to it, measuring equity through debt - an indirect measure.

Furthermore, his discussion of the availability of the dividends yields used in the DCF and the risk-free rate of return and yield on A-rated public utility bonds used in the CAPM/RP method misses the mark. It is not a matter of having available information, but rather the type of information used. The DCF measures equity more directly through the stock information (using equity information),

[36] Columbia Statement No. 110-R, pages 40-41.

[37] I&E Statement No. 1, pages 19-22.

whereas the RP methods measures equity indirectly through the use of debt information.

COMPARABLE EARNINGS

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE COMPARABLE EARNINGS (CE) METHOD.

A. Mr. Moul only states that I never explain why or how the inclusion of non-regulated companies that have dissimilar risks, a changing barometer group, lack of current market data, and historical Commission treatment diminishes the value of the CE approach.[38]

Q. CAN YOU EXPLAIN HOW THE INCLUSION OF NON-REGULATED COMPANIES THAT HAVE DISSIMILAR RISKS, AND A CHANGING BAROMETER GROUP DIMINISHES THE VALUE OF THE CE APPROACH?

A. Yes. Since none of the companies in Mr. Moul's analysis are utility companies, they may not have similar risks in the long run. Further, while the companies Mr. Moul selected using Value Line's July 2012 information may have been similar based on his factors (timeliness rank, technical rank, price stability, and beta) these factors can change. Using Value Line information as of January 2013, many of

[38] Columbia Statement No. 110-R, page 42, lines 6-10.

the companies presently on Mr. Moul's list would be excluded from his CE group given the new updated parameters of the Gas Group. Church & Dwight and Dollar General are two such examples. There may also be other companies which would need to be added to Mr. Moul's CE group. These changes would require a new CE barometer group, and show that the risks of the companies change with the economy. Value Line updates several industries a week on a rotating basis, and it takes 3 months for the same industry to be re-evaluated. As one can see, using the returns for the companies listed in Mr. Moul's CE group going back six months, let alone six years, is not appropriate because the companies are only similar for one short period of time (as little as one week). Therefore, the results for any given week cannot be relied upon to determine long-term costs of equity.

Q. CAN YOU PLEASE EXPLAIN HOW THE LACK OF CURRENT MARKET DATA DIMINISHES THE VALUE OF THE CE APPROACH.

A. Yes. Mr. Moul includes the historical years of 2007-2011. He proceeds to exclude current market data for the years 2012-2014. Mr. Moul then picks up using projected information from 2015-2017. This is different from the use of the years 2006-2016 in my DCF as the years are continuous (with no exclusions of years, as Mr. Moul has done). This exclusion of data diminishes the value of the CE approach as Mr. Moul is excluding three years of recent information, which is clearly imprudent when Mr. Moul's goal is to "span an entire business cycle." Furthermore, the historical (2007 to 2011) and estimated (2015 to 2017) accounting returns do not include any information on what market return investors expect today (2013).

Q. CAN YOU PLEASE EXPLAIN HOW HISTORICAL COMMISSION TREATMENT DIMINISHES THE VALUE OF THE CE APPROACH?

A. Yes. First, I would like to discuss the Bluefield case which Mr. Moul cites in his direct testimony.[39] Mr. Moul's excerpt omitted the following *italicized text, "undertakings which are attended by corresponding risks and uncertainties, (but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.)"* (Emphasis added). Mr. Moul's Exhibit No. 400, page 33 of 33, Schedule 13 [2 of 2], shows that he has included highly profitable enterprises such as Hershey Co. with an average return of 85.5 % and projecting a 56.0% return. Therefore, these companies which are highly profitable in nature should be excluded from the barometer group all together. Also, even though Mr. Moul has excluded any return higher than 20% in part of his analysis, he leaves the company in the barometer group list and includes its return if it is under 20% in other parts of his analysis. A company with returns over 20% is an inappropriate source of returns in Mr. Moul's analysis, and should be completely excluded from the analysis, not just when its returns are over 20%.

[39] Columbia Statement No. 10, page 44, lines 13-25.

Second, the Commission has long recognized the problem with the CE method. Regarding the use of non-utility companies' historical book earnings in an attempt to determine a cost of equity for a utility, the Commission stated:

> The use of nonregulated companies as a comparable group for regulated firms under the comparable earnings method of computing a rate of return on common equity requires numerous unsupportable assumptions and results in a highly speculative finding.

Pennsylvania Public Utility Commission v. Philadelphia Electric Co. (1980) 33 PUR4th 319, 341 (1980).

> NFGD employed comparable earnings as a check on the common equity cost rates produced by its other methodology. NFGD M.B. p. 170. NFGD did not use comparable earnings as a common equity cost rate determinant. Additionally, it was noted that comparable earnings are not market related but accounting related ratios.

Pa PUC v National Fuel Gas Distribution Corp., Docket No. R-00940021, p. 199, Order entered December 1, 1994.

<u>REGULATORY SUPPORT</u>

Q. PLEASE SUMMARIZE MR. MOUL'S REBUTTAL REGARDING REGULATORY SUPPORT.

A. Mr. Moul uses two sources to determine that the average return granted in 2011 and 2012 is 10.15%, with a range of 9.78% to 10.76%. He further uses Value Line to determine the average forecast for the Gas Group is 10.1%.[40]

[40] Columbia Statement No. 110-R, pages 44-45.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THESE RETURN VALUES?

A. Mr. Moul uses other state and regulatory commissions to determine an appropriate return value for Columbia in Pennsylvania.

First, each case is to be determined on its own merits, not on the merits of other cases.

Second, without time to fully and appropriately research these reports, these reports may contain those utilities which have significantly higher risk than that of Columbia. For example, Pennsylvania electric utilities are deregulated. However, there are many other jurisdictions which still regulate the generation portion of electric, which would increase their risk compared to Columbia. Electric companies are not representative of the return which should be allowed a gas company. If electric companies were comparable, they would be included in the barometer group; which they are not. Furthermore, historical authorized returns on equity may be a result of settlement negotiations where the settlement return may have been negotiated between parties involved with offsetting considerations for other settlement issues.

Regarding Mr. Moul's Value Line projected returns, the returns for 2015-2017 are irrelevant. Due to the increased infrastructure replacement needed by Columbia, and the historical 2 year rate case cycle, it is unlikely that Columbia will wait until 2017 to return for a rate case. I would further like to note that

ValueLine's projection of NiSource's return on equity is only 8.0% in 2013 and 9.0% in 2015-2017.

Q. DOES YOUR EQUITY RECOMMENDATION SIGNIFICANTLY UNDERSTATE THE COMPANY'S COST OF COMMON EQUITY?

A. No. The 8.51% cost of common equity recommendation provides adequate financial compensation to stockholders for the low risk they face, even in these economic times, while protecting against excessive rates.

MANAGEMENT EFFICIENCY POINTS

Q. PLEASE SUMMARIZE MR. KEMPIC'S TESTIMONY REGARDING MANAGEMENT EFFICIENCY POINTS.

A. Mr. Kempic addresses Ms. Maurer's testimony regarding customer programs and customer service.

Q. WHAT COMMENTS DOES I&E HAVE REGARDING CUSTOMER PROGRAMS AND CUSTOMER SERVICE?

A. Ms. Mauer will testify that over the past 3 years, Columbia's quality of service scores have decreased while the industry average has increased. The Thoroughbred Survey has no data for the industry, and thus no conclusion other than Columbia itself has improved, with no relative benchmark. Finally, Columbia's UCARE is within 1% of the industry average, and since the numbers are low, a little change makes a huge impact. Columbia has still not shown that its performance is other than average when compared to that of the industry.

Q. WHAT COMMENTS DO YOU HAVE REGARDING MANAGEMENT PERFORMANCE?

A. Mr. Kempic believes that Columbia has provided exceptional customer service and is a leader within the utility industry.[41] As stated above, Columbia has not shown that it has gone above and beyond. However, I&E describes Columbia as only average. Therefore, Columbia does not deserve management efficiency points. It would further be imprudent to increase the cost of equity to a rate that would be "double collecting" in recognition for the same "incentive"; once through expenses and once through rate of return.

<u>OVERALL RATE OF RETURN</u>

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOU DIRECT TESTIMONY?

A. No. I continue to support each recommendation made in I&E Statement No. 1.

[41] Columbia Statement No. 101-R, page 12, line 4.

Q. PLEASE SUMMARIZE YOUR OVERALL RATE OF RETURN RECOMMENDATION.

A. I recommend the following rate of return for Columbia:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.11 %	5.64 %	2.49 %
Short-Term Debt	3.57 %	1.60 %	0.06 %
Common Equity	52.32 %	8.51 %	4.45 %
Total	100.00 %		7.00 %

Source: I&E Exhibit No. 1, Schedule No. 1, Page 1.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Exhibit No. 1-SR
Witness: Emily Sears

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Exhibits to Accompany

the

Surrebuttal Testimony

of

Emily Sears

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

2-13-13
Hbg

I&E Exhibit No. 1-SR
Schedule No. 1
Page 1 of 2

U.S. Securities and Exchange Commission

Ex-Dividend Dates:
When Are You Entitled to Stock and Cash Dividends

Have you ever bought a stock only to find out later that you were not entitled to the next cash or stock dividend paid by the company? To determine whether you should get cash and most stock dividends, you need to look at two important dates. They are the "record date" or "date of record" and the "ex-dividend date" or "ex-date."

When a company declares a dividend, it sets a record date when you must be on the company's books as a shareholder to receive the dividend. Companies also use this date to determine who is sent proxy statements, financial reports, and other information.

Once the company sets the record date, the stock exchanges or the National Association of Securities Dealers, Inc. fix the ex-dividend date. The ex-dividend date is normally set for stocks **two business days before** the record date. If you purchase a stock on its ex-dividend date or after, you will not receive the next dividend payment. Instead, the seller gets the dividend. If you purchase before the ex-dividend date, you get the dividend.

Here is an example:

Declaration Date	Ex-Dividend Date	Record Date	Payable Date
7/27/2004	8/6/2004	8/10/2004	9/10/2004

On July 27, 2004, Company XYZ declares a dividend payable on September 10, 2004 to its shareholders. XYZ also announces that shareholders of record on the company's books on or before August 10, 2004 are entitled to the dividend. The stock would then go ex-dividend two business days before the record date.

In this example, the record date falls on a Tuesday. Excluding weekends and holidays, the ex-dividend is set two business days before the record date or the opening of the market – in this case on the preceding Friday. This means anyone who bought the stock on Friday or after would not get the dividend. At the same time, those who purchase before the ex-dividend date receive the dividend.

With a significant dividend, the price of a stock may move up by the dollar amount of the dividend as the ex-dividend date approaches and then fall by that amount after the ex-dividend date. A stock that has gone ex-dividend is marked with an "x" in newspapers on that day.

Sometimes a company pays a dividend in the form of stock rather than cash. The stock dividend may be additional shares in the company or in a subsidiary being spun off. The procedures for stock dividends may be different from cash dividends. The ex-dividend date is set the first business day after the stock dividend is paid (and is also after the record date).

If you sell your stock before the ex-dividend date, you also are selling away your right to the stock dividend. Your sale includes an obligation to deliver any shares acquired as a result of the dividend to the buyer of your shares, since the seller will receive an I.O.U. or "due bill" from his or her broker for the additional shares. Thus, it is important to remember that the day you can sell your shares without being obligated to deliver the additional shares is ***not*** the first business day after the record date, but usually is the first business day after the stock dividend is paid.

If you have questions about specific dividends, you should consult with your financial advisor. You can also get information by going to your library and reading *Standard and Poor's Dividend Record Binder*.

http://www.sec.gov/answers/dividen.htm

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement - Set RR

Question No.: I&E-RR-14-D

Reference Columbia Statement No. 10, Appendix E, page 11, lines 19-26. Provide the step-by-step, detailed calculation to solve for ku = 7.94%.

Response:

Please refer to the Microsoft Excel spreadsheet that is attached as Attachment A to this response. The solution for ku is provided in cell B54 of the spreadsheet. All formulas are intact.

Columbia Gas of Pennsylvania, Inc.

Gas Group

		AGL RES INC (NYSE:AGL)	ATMOS ENERGY CORP (NYSE:ATO)	LACLEDE GROUP (NYSE:LG)	NEW JERSEY RES (NYSE:NJR)	NORTHWEST NAT GAS CO (NYSE:NWN)	PIEDMONT NAT GAS INC (NYSE:PNY)	SOUTH JERSEY INDS INC (NYSE:SJI)	SOUTHWEST GAS (NYSE:SWX)	WGL HLDGS INC (NYSE:WGL)	Average
Fiscal Year		31-Dec-11	30-Sep-11	30-Sep-11	30-Sep-11	31-Dec-11	31-Oct-11	31-Dec-11	31-Dec-11	30-Sep-11	
Capitalization at Fair Values											
	Debt(D)	3,938,000	2,560,945	443,739	471,022	808,724	831,323	533,400	1,319,318	720,900	1,291,930
	Preferred(P)	0	0	0	0	0	0	0	0	28,173	3,130
	Equity(E)	4,944,420	2,930,121	869,191	1,643,785	1,282,415	2,364,075	1,716,369	1,952,674	2,006,844	2,189,988
	Total	8,882,420	5,491,066	1,312,930	2,114,807	2,091,139	3,195,398	2,249,769	3,271,992	2,755,917	3,485,049
Capital Structure Ratios											
	Debt(D)	44.33%	46.64%	33.80%	22.27%	38.67%	26.02%	23.71%	40.32%	26.16%	33.55%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.02%	0.11%
	Equity(E)	55.67%	53.36%	66.20%	77.73%	61.33%	73.98%	76.29%	59.68%	72.82%	66.34%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock											
	Issued	117,000.000	90,296.482	22,430.734	41,421.786	26,756.000	72,318.000		45,956.088	51,365.337	
	Treasury	0.000	0.000	0.000	2,808.093	0.000	0.000		0.000	0.000	
	Outstanding	117,000.000	90,296.482	22,430.734	38,613.693	26,756.000	72,318.000	30,212.453	45,956.088	51,365.337	
	Market Price	$42.26	$32.45	$38.75	$42.57	$47.93	$32.69	$56.81	$42.49	$39.07	
Capitalization at Carrying Amounts											
	Debt(D)	3,576,000	2,212,565	364,357	434,372	681,700	675,000	426,400	1,258,923	587,200	1,135,169
	Preferred(P)	0	0	0	0	0	0	0	0	28,173	3,130
	Equity(E)	3,318,000	2,255,421	573,331	776,257	714,488	996,923	624,114	1,226,020	1,202,715	1,298,585
	Total	6,894,000	4,467,986	937,688	1,210,629	1,396,188	1,671,923	1,050,514	2,484,943	1,818,088	2,436,884
Capital Structure Ratios											
	Debt(D)	51.87%	49.52%	38.86%	35.88%	48.83%	40.37%	40.59%	50.66%	32.30%	43.21%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.55%	0.17%
	Equity(E)	48.13%	50.48%	61.14%	64.12%	51.17%	59.63%	59.41%	49.34%	66.15%	56.62%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.75	0.70	0.55	0.65	0.60	0.70	0.65	0.75	0.65	0.67

Hamada	Bl	=	Bu	[1+		(1 - t)	D/E	+		P/E	]						
	0.67	=	Bu	[1+		(1-0.35)	0.5057	+		0.0017	]						
	0.67	=	Bu	[1+		0.65	0.5057	+		0.0017	)						
	0.67	=	Bu	1.3304													
	0.50	=	Bu														
Hamada	Bl	=	0.50	[1+		(1 - t)	D/E	+		P/E	]						
	Bl	=	0.50	[1+		0.65	0.7632	+		0.0030	]						
	Bl	=	0.50	1.4991													
	Bl	=	0.75														
M&M	ku	=	ke	-	(((	ku	-	i	)			1-t	)	D	/	E	)-(ku - d) P / E
	7.94%	=	9.15%	-	(((	7.94%	-	4.24%	)			0.65	)	33.55%	/	66.34%	)-(7.94% - 5.68%) 0.11% / 66.34%
	7.94%	=	9.15%	-	(((	3.70%			)			0.65	)	0.5057			)-(2.26%) 0.0017
	7.94%	=	9.15%	-	((	2.41%							)	0.5057			)-(2.26%) 0.0017
	7.94%	=	9.15%	-		1.22%											- 0.00%
M&M	ke	=	ku	+	(((	ku	-	i	)			1-t	)	D	/	E	)+(ku - d) P / E
	9.79%	=	7.94%	+	(((	7.94%	-	4.24%	)			0.65	)	43.21%	/	56.62%	)+(7.94% - 5.68%) 0.17% / 56.62%
	9.79%	=	7.94%	+	(((	3.70%			)			0.65	)	0.7631			)+(2.26%) 0.0030
	9.79%	=	7.94%	+	((	2.41%							)	0.7631			)+(2.26%) 0.003
	9.79%	=	7.94%	+		1.84%											+ 0.01%

I&E Exhibit No. 1-SR
Schedule 3

Risk Free Rate Treasury note 10-yr Note	Yield
4Q 2012	1.71
1Q 2013	1.80
2Q 2013	1.90
3Q 2013	2.00
4Q 2013	2.20
1Q 2014	2.30
2Q 2014	2.40
2014-2018	3.90
Average	2.28

Source:
Blue Chip
February 1, 2012

Seeking Alpha $^{\alpha}$

Advantages of Investing in Utility ETFs

February 4, 2008
by: Del Thiessen

| includes: DBU, IDU, JXI, NLR, PBD, PBW, PHO, PUI, QCLN, RYU, UTH, VPU, XLU

Utilities have a history of good dividend returns and safety. It is not true, as some people claim, that utilities are immune from downturns in a sinking market, but they are less likely to fall precipitously under adverse economic conditions.

Surprisingly, public utilities offer value, profit, and reliability when the market is at its worse. Roger Conrad's Utility Forecaster of January, 2008 (www.utilityforecaster.com) presents an extensive menu of high-yield utilities. He says, in their favor: "Utility stocks haven't gone straight to the moon in five years. But they've come pretty close: The index of 20 electric utilities traded on the Philadelphia Stock Exchange tripled from late-2002 lows and are 50 percent above their 2000 peak." Many, in fact, are trading at their 52-week highs.

The following table illustrates the relative advantage of utilities, in contrast to other sectors of the market. The data are for the losses from October 9, 2007 to January 23, 2008 (*Wall Street Journal*, Jan 23, 2008). They are exemplary for sector performance under very adverse market conditions.

click to enlarge

Sector	Loss in 3 ½ Months (%)
Utilities	**4.5**
Health Care	5.9
Food & Beverage	6.7
Chemicals	10.3
Oil & Gas	10.4
Personal & Household Goods	10.4
Telecommunications	10.6
Retail	17.3
Technology	18.1
Construction & Materials	19.1
Basic Resources	19.8
Media	19.9
Industrial Goods & Services	20.0
Travel & Leisure	20.1
Automobiles & Parts	20.2
Insurance	20.2
Financial Services	23.9
Banks	25.2

In this example Utilities, overall, suffer the lowest loss during an economic downturn – less than five percent. Many individual utility stocks do better, and it is those that you should search for. One can cut the sector loss by about 50% by selecting stocks with the strongest fundamentals. In any case, the 4.5% loss for Utilities is less than the overall dividend yield. Thus, one can argue that there has been no loss for Utilities.

Direct Purchase [DP] and Automatic Reinvest [AR] Plans

Several utility companies have stock plans that allow investors to buy shares in reinvestment plans without brokerage fees. This is a neat aspect of the plans, as brokerage fees whittle down your profits. For example, if you purchase shares each month, and the brokerage commission is only $7.00 a purchase, you will be spending $84.00 a year on commissions alone.

This is money that won't be earning you additional money through reinvestment. You can skip this expense by Direct Purchase [DP] of funds and Automatic Reinvestment [AR] of investment dollars, appreciation, and dividends. Reducing brokerage fees to zero in a dividend reinvestment system can make you thousands of dollars. You still have to do your own stock analyses, but you want to do that anyway.

Several of these DP and AR plans are listed in the following table. Check for current prices, yield, and total returns. They represent utilities with interests ranging from electricity, to nuclear power, and water. Most require $250 or sometimes $500 as an initial investment. Additional contributions can be made automatically through your personal or business bank account. Many more DP/AR utility stocks are available through *Utility Forecaster*, www.utilityforecaster.com (703.394.4931). A more diverse selection can be found at *American Association of Individual Investors*, www.aali.com.

SELECTED UTILITY STOCKS WITH DP & AR PLANS

Name & Ticker	Phone Number	Reinvest Yield %
AT&T (T)	800.351.7221	3.5
Chevron (CVX)	800.842.7629	2.5
Consolidated Water (CWCO)	877.390.3093	0.8
Duke Energy (DUK)	800.488.3853	4.2
Southern Company (SO)	800.554.7626	4.1
Verizon Communications (VZ)	800.631.2355	3.7

Making It Big with Utility ETFs

Fourteen ETF Utility Funds are listed in the following table. They share many of the conservative characteristics found with stock utility companies, but they have the added advantages of diverse holdings and relatively low risk. None of these, as far as I known, have DP/AR plans, but they often do generate dividends. You can construct a strong portfolio of utility ETFs and reinvest profits periodically in those that maximize your returns.

SELECTED UTILITY ETFs AS OF JANUARY, 2008

Name and Ticker for Utility ETF	Primary Concentration	Yield %
PowerShares Dynamic Utilities (PUI)	Domestic: traditional electricity	2.19
First Trust NASDAQ Clean Edge US Liquid (QCLN)	Domestic solar	NA
iShares S&P Global Utilities (JXI)	Global: electricity, gas, water	0.78
Vanguard Utilities ETF (VPU)	Domestic: electricity	2.44
Utilities Select Sector SPDR ETF (XLU)	Domestic: electricity, gas, water	2.57
PowerShares Wilder-Hill Clean Energy (PBW)	Domestic: solar, green energy	NA
PowerShares FTSE RAFE Utilities (PRFU)	Domestic: electricity	3.02
Utilities HOLDRs (UTH)	Domestic: electricity	NA
Wisdom Tree International Utilities (DBU)	Global: electricity, gas, water	0.79
Market Vectors Global Nuclear Energy ETF (NLR)	Global: International investments	NA
PowerShares Water Resources (PHO)	Domestic: water	0.40
PowerShares Global Clean Energy (PBD	Global: solar, wind	NA
Rydex S&P Equal Weight Utilities (RYU)	Domestic: electricity	2.89
iShares Dow Jones US Utilities ETF (IDU)	Domestic: electricity, gas, water	NA

Several of these have demonstrated great returns: IDU 1yr = 28.25%; RYU YTD = 10.00%; PHO YTD = 16.73%; DBU YTD = 23.28%; UTH YTD = 9.91%; PRFU 1 yr = 11.53%; PBW 1 yr = 58.50%; XLU 1 yr = 19.86%; VPU YTD 10.14%; JXI 1 yr = 22.46%.

Advantages of Investing in Utility ETFs

Many of the utility ETFs are new to the market but should do well over the long-term. Certainly, they reflect the most prominent megatrends in history. The key ingredients in the recipe for profitable utility ETFs are that:

1. The holdings are well-known utility stocks that show long-term price stability and have a history of increasing yields.

2. Like utility stocks, utility ETFs show reduced volatility in tremulous markets. They rarely show knee-jerk reactions to market corrections.

3. Utility ETFs with diverse holdings spread the risk associated with financial allocations. Holdings have assets among electricity, natural gas, coal, solar and wind generation, biofuels, nuclear energy, and even water.

4. Utility ETFs can be selected to reflect foreign allocations and specified geopolitical regions.

5. Utilities are useful investment vehicles because the world cannot do without them. Over time the demand for utilities and what they can do increases. Utilities typically have good dividend payouts, thus compensating for temporary decreases in prices.

6. Last, there are links between increasing interest in clean energy and growth of utility funds. Current growth of clean

energy ETFs (solar, wind, biofuels, water, nuclear, etc.) are likely to stabilize utility use and increase their efficiency. Companies that can't make adjustments will become Darwinian history. Technical advances that favor clean energy will also favor the transition of traditional utility companies into key players in alternative energy sources, energy production and transmission, and in waste management. It is clearly a win-win synergy.

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Lower Risk Stocks

October 20, 2011

Sudhir Nanda, T. Rowe Price's head of quantitative equity research and manager of a broadly diversified small-cap growth portfolio, particularly focuses on companies with favorable characteristics that he believes can help the portfolio outperform in down markets.

T. Rowe Price portfolio managers and analysts have long approached equity research in a bottom-up way, studying the fundamental metrics and management of companies. But quantitative equity research supplements that with a top-down approach and can help identify companies for portfolio managers to avoid or consider.

THE VIDEO YOU ARE TRYING TO WATCH IS CURRENTLY UNAVAILABLE. PLEASE CHECK BACK SOON.

Quantitative Equity Research Augments Fundamental Research

Supplements T. Rowe Price fundamental research by screening as many as 10,000 stocks globally for certain favorable characteristics, such as growing dividends, good free cash flow, and stock buybacks.

Provides candidates for further analysis and can help identify companies with deteriorating financial profiles that should be avoided. Avoiding poorly performing companies can be as important to overall portfolio performance as finding outperformers.

Seeking or Avoiding Certain Stock Characteristics Can Help in Down Markets

Avoid stocks with high beta (or high volatility), as well as companies that are highly leveraged (high debt ratios).

Seek reasonably valued stocks with high return on equity, a measure of a company's profitability.

Favor companies with high free cash flow, which can be used to pay or increase dividends or to buy back stock.

Avoid companies with highly variable earnings and cash flow relative to industry peers.

Dividends Are Important to Long-Term Investing

Since 1926, about 42% of the S&P 500's return has come from dividends.

T. Rowe Price research shows that dividend-paying companies, especially those that grow their dividends, have outperformed over time, especially in down markets.

High dividend yields with high payout ratios can signal distress, so lower payout ratios (the proportion of earnings paid out as dividends) and dividend growth also need to be taken into account.

Companies with lower payout ratios have been able to sustain and increase their dividends.

With the S&P 500's dividend yield above 10-year Treasury yields, dividends are particularly attractive to income-oriented investors.

Historically, S&P 500 dividend growth over time has exceeded inflation—also a plus for income—oriented investors who rely on dividends.

Utilities, Despite Steady Earnings and Dividends, May Not Be as Favorable as Other Defensive Sectors

According to T. Rowe Price research covering the 10-year period ended September 30, 2011, three defensive sectors—consumer staples, health care, and utilities—have outperformed the S&P 500 in down markets 75% of the time.

However, we prefer consumer staples and health care because they tend to have decent growth characteristics, may pay dividends, and have outperformed utilities in up markets.

Nanda Uses Quantitative Equity Research While Managing T. Rowe Price's Diversified Small-Cap Growth Portfolios

We look for fast-growing companies that have sustainable growth characteristics and reasonable valuations, produce lots of cash, have high returns on equity, and are buying back stock.

Our goal is to provide steady outperformance with lower risk than that of the small-cap market. We believe preventing losses in down markets can help performance over time.

Past performance cannot guarantee future results. It is not possible to invest directly in an index. Unlike stocks, U.S. treasury securities are guaranteed as to the timely payment of interest and principal. Stocks generally fluctuate in value more than bonds and may decline significantly over short time periods. Stocks and sectors may not perform in line with a manager's expectations.

Securities issued by small-cap companies are likely to be more volatile than those issued by larger companies. Small-sized companies often have less experienced management, narrower product lines, more limited financial resources, and less publicly available information than larger companies. Investments in foreign securities may be adversely affected by political and economic conditions overseas, reduced liquidity, or decreases in foreign currency values relative to the U.S. dollar. These risks may be amplified in emerging market countries.

This information is provided for informational purposes only and is not intended to reflect a current or past recommendation, or investment advice of any kind. Opinions and commentary do not take into account the investment objectives or financial situation of any particular investor or class of investor. Investors will need to consider their own circumstances before making an investment decision.

Download a prospectus

I&E Statement No. 2
Witness: Christine Wilson, CPA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Direct Testimony

of

Christine Wilson, CPA

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket Nos. R-2012-2321748**
	:	**M-2012-2323645**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION OF THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Christine Wilson, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as I&E Statement No. 2, I&E Exhibit No. 2, I&E Statement No. 2-SR, and I&E Exhibit No. 2-SR were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Christine Wilson

Christine Wilson
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: February 13, 2013

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Q. STATE YOUR FULL NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Christine Wilson. I am a Fixed Utility Financial Analyst in the Technical Division of the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"). My business address is P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My educational and professional background is attached to this testimony as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in rate proceedings. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers and the Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company") and make recommended adjustments to the Company's proposed operating and maintenance ("O&M") expenses for the fully projected future test year ("FPFTY") ending June 30, 2014.

My recommended adjustments relate to the following areas: Gas Technology Institute ("GTI") expense; NiFIT expense; odorization expense; other O&M – Longwall Mining amortization; pension expense, profit sharing and stock rewards; rents and leases; system services - business promotion services; incentive compensation; labor; employee insurance/thrift plans; and payroll taxes.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules relating to my testimony.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following tables summarize my recommended adjustments.

TABLE I

O&M Adjustments:	Columbia Claim	I&E Adjustment	I&E Recommended Allowance
GTI Expense	$207,674	($57,674)	$150,000
NiFIT Expense	$1,010,000	($662,257)	$347,743
Odorization Expense	$75,000	($14,254)	$60,746
Other O&M – Longwall Mining Amortization	$56,074	($56,074)	$0
Pension Expense	$3,746,730	($3,208,326)	$538,404
Profit Sharing/Stock Rewards:	$231,934	($231,934)	$0
Direct-Profit Sharing	$139,296	($139,296)	$0
Direct-Stock Rewards	$1,018,707	($1,018,707)	$0
NCSC-Allocated			
Rents and Leases	$1,677,551	($33,699)	$1,643,852
System Svcs. – Business Promotion Services	$1,608,646	($1,608,646)	$0
Incentive Compensation	$1,381,722	($707,142)	$674,580
System Svcs. – Incentive Comp.	$1,869,905	($934,953)	$934,952
Labor, net of profit sharing/ stock rewards	$26,297,376	($619,725)	$25,677,651
Employee Insurance Plans & Thrift Plan – existing employees	$4,790,371	($112,891)	$4,677,480
Payroll Taxes - Direct	$1,617,921	($103,798)	$1,514,123
System Svcs. – Payroll Taxes	$912,429	($74,048)	$838,381
Total O&M Adjustments		**($9,583,424)**	

TABLE II

Rate Base Adjustments:	Columbia Claim	I&E Adjustment	I&E Recommended Allowance
Capitalized Pension Exp.	$1,806,437	($1,527,591)	$278,846
Employee Profit Sharing	$111,825	($111,825)	$0
Employee Stock Rewards	$67,160	($67,160)	$0
System Svcs. – Profit Sharing	$27,942	($27,942)	$0
System Svcs. – Business Promotion Services	$471,187	($471,187)	$0
Incentive Compensation	$666,184	($316,811)	$349,373
System Svcs. – Incentive Compensation	$463,684	($231,842)	$231,842
Labor	$12,679,022	$619,725	$13,298,747
Employee Insurance Plans & Thrift Plan – existing employees	$2,309,629	$112,891	$2,422,520
Payroll Taxes - Direct	$780,065	$22,543	$802,608
System Svcs. – Payroll Taxes	$226,257	($18,362)	$207,895
Total Rate Base Adjustments		($2,017,561)	

GAS TECHNOLOGY INSTITUTE EXPENSE

Q. WHAT IS GAS TECHNOLOGY INSTITUTE EXPENSE?

A. According to Company Witness Krajovic (Columbia St. No. 6, p. 16), "[t]he Gas Technology Institute ("GTI") is a non-profit organization that provides a gas consumer research and development ("R&D") program." Specifically, the Company participates in the GTI Operations Technology Development Program (Columbia St. No. 6, p. 19).

Q. WHAT IS THE COMPANY'S CLAIM FOR GTI EXPENSE?

A. The Company is claiming $207,674 (415,347 x $0.50) which is calculated by multiplying the basic charge of 50 cents per customer by 415,347 customers (Columbia Ex. No. 104, Sch. 2, p. 19).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. According to Company Witness Krajovic, the operations projects conducted by GTI benefit Columbia's ratepayers by helping to minimize increases to O&M costs, increasing safety, enhancing deliverability, and increasing system integrity (Columbia St. No. 6, pp. 16-17). Furthermore, Ms. Krajovic states that the prospect of a return on private sector R&D investments is more remote, but by using GTI, benefits are shared by consumers, the general public, and gas companies, making it more cost effective (Columbia St. No. 6, p. 17).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR GTI EXPENSE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR GTI EXPENSE?

A. I recommend an allowance of $150,000, which is a reduction of $57,674 ($207,674 - $150,000) to the Company's claim. This amount is the established minimum charge GTI assesses per company (I&E Ex. No. 2, Sch. 1, p. 3).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company's participation in research and development programs is voluntary. GTI funding is elective and not a necessary operational expense. Furthermore, on May 21, 2008, GTI officially lowered the minimum dues level to $150,000 (I&E Ex. No. 2, Sch. 1, p. 3). Even though the Company stated that it funded the GTI Operations Technology Development ("OTD") Program in the amount of $165,000 (Columbia St. No. 6, p. 20), in response to I&E-RE-115-D the Company admits it actually contributed $0 in 2009, $135,000 in 2010, and $0 in 2011 (I&E Ex. No. 2, Sch. 2, p. 2). Thus, Columbia has incurred an expense, and GTI has accepted payments, of substantially less than $150,000 in recent years.

I acknowledge Ms. Krajovic's claim that participation in this organization shares cost across a broader industry base and ultimately benefits gas consumers generally (Columbia St. No. 6, p. 16). I therefore recognize there is some value to ratepayers. I do not believe, however, that the Company has substantiated that payment of an amount above the minimum dues level provides a measurably higher level of benefit to Columbia's Pennsylvania ratepayers (I&E Ex. No. 2, Sch. 3). Therefore, I recommend an allowance amount equal to the minimum dues payment of $150,000, or a reduction of $57,674 ($207,674 - $150,000) to the Company's claim.

NiFIT EXPENSE

Q. WHAT IS NiFIT EXPENSE?

A. NiSource, Columbia's parent, is installing a new software system, and the endeavor has been labeled the NiFIT project. The Company has described certain costs related to its new system (approximately $2.02 million) as unusual, non-recurring startup costs that are appropriately classified as operating and maintenance expenses (Columbia St. No. 4, p. 35).

Q. WHAT IS THE COMPANY'S CLAIM FOR NiFIT EXPENSE?

A. The Company is claiming $1,010,000 for the first year's amortization of the total two-year projected O&M cost (Columbia Ex. No. 104, Sch. 1, p. 2, line 30).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has proposed to amortize the total NiFIT expense over a two-year period which is in line with the Company's recovery of normalized rate case expense (Columbia St. No. 4, p. 34).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR NiFIT EXPENSE?

A. No.

Q. WHAT DO YOU RECOMMEND FOR NiFIT EXPENSE?

A. I recommend an allowance of $347,743, or a reduction of $662,257 ($1,010,000 – $347,743) for NiFIT expense.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. My recommendation removes duplicate labor costs from the NiFIT expense. The Company has stated that labor costs are included in NiFIT expense and in labor costs (I&E Ex. No. 2, Sch. 4). Since the NiFIT system installation is expected to occur over a fixed amount of time and is temporary in nature, it is not likely that the employees assigned to installation of the new computer system will have moved into new permanent positions. I believe the Company has not substantiated the need or intention to fill those positions with newly hired employees. Therefore, to eliminate a duplication of payroll-related costs I am recommending that internal labor costs be removed from the NiFIT expense claim. Furthermore, I believe that a two-year recovery for NiFIT O&M expense is too short. My recommendation incorporates a 5-year recovery. This recovery period better matches the expenses associated with the capital asset which has a value of $4.037 million (Columbia's share) (Columbia St. No. 13, p. 6).

Q. HOW DID YOU CALCULATE YOUR RECOMMENDATION?

A. My recommendation is based upon the Company's total O&M-related NiFIT costs, less the internal labor amount that is already included in the Company's labor cost. My recommendation was calculated as follows:

Total NiFIT O&M	$2,020,000	
Less Total Internal Labor	<u>$281,286</u>	I&E Ex. No. 2, Sch. 4
Equals	$1,738,714	
Divided by 5 Year Recovery	<u>÷ 5</u>	
I&E Recommended Allowance	<u>$347,743</u>	

<u>ODORIZATION EXPENSE</u>

Q. WHAT IS ODORIZATION EXPENSE?

A. The Company is assuming certain odorization responsibilities that were previous taken care of by its upstream supplier (Columbia St. No. 4, p. 36).

Q. WHAT IS THE COMPANY'S CLAIM FOR ODORIZATION EXPENSE?

A. In its filing the Company claims $75,000 for odorization (Columbia Ex. No. 104, Sch. 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. Estimates made available by the Company's engineering group provide the basis for the claim (Columbia St. No. 4, p. 37).

Q. DURING THE DISCOVERY PROCESS, HAS THE COMPANY INDICATED ANY CHANGES TO ITS ORIGINAL CLAIM?

A. Yes. The Company reduced its number of odorizers to six from the seven originally claimed. As a result, the Company's updated expense claim is $60,746, or a reduction of $14,254 ($75,000 - $60,746) (I&E Ex. No. 2, Sch. 5).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR ODORIZATION EXPENSE?

A. Yes. I am willing to accept the Company's updated claim.

<u>OTHER O&M – LONGWALL MINING AMORTIZATION</u>

Q. EXPLAIN THE COMPANY'S INCLUSION OF AMORTIZATION FOR LONGWALL MINING.

A. The Company has included an annual amortization of $54,210 in its Other O&M Expense for Longwall Mining (I&E Ex. No. 2, Sch. 6, p. 1).

Q. WAS THE COMPANY'S AMORTIZATION FOR LONGWALL MINING ADJUSTED FOR INFLATION?

A. Yes. All items in Other O&M (Columbia Ex. No. 104, Sch. 1, p. 2), including Longwall Mining, were adjusted for future test year ("FTY") inflation (using a 1.85% inflation factor) and FPFTY inflation (using a 1.56% inflation factor), thereby increasing the amortization for Longwall Mining to $56,074 [($54,210 x 1.0185) x 1.0156].

Q. WHAT IS THE BASIS FOR COLUMBIA'S INFLATION ADJUSTMENTS?

A. In its filing, the Company made two sets of inflation adjustments: one for the FTY ending May 31, 2013 and one for the FPFTY ending June 30, 2014. The Company applied its inflation factors based on the Gross Domestic Product ("GDP") to FTY and FPFTY expense items not otherwise adjusted and subject to inflation (Columbia St. No. 4, p. 37).

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM FOR LONGWALL MINING AMORTIZATION AND THE RELATED INFLATION ADJUSTMENTS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING LONGWALL MINING AMORTIZATION EXPENSE AND THE RELATED INFLATION ADJUSTMENTS?

A. I recommend that the total amortization expense of $56,074 for Longwall Mining be disallowed.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company has indicated that prior to the end of the FPFTY this regulatory asset will be completely amortized and the annual amortization amount along with the associated inflation adjustments must be removed from the claim (I&E Ex. No. 2, Sch. 6, p. 3).

PENSION EXPENSE

Q. WHAT IS PENSION EXPENSE?

A. The Company's claim for pension expense is based on pension contributions made by the Company to its pension trust (Columbia St. No. 4, p. 14). The Company has also included an amount for its supplemental retirement income plan in its pension claim (Columbia Ex. No. 104, Sch. 2, p. 12).

Q. WHAT IS THE COMPANY'S CLAIM FOR PENSION EXPENSE?

A. The Company has a total pension expense of $5,553,167 which can be further broken down between pension expense of $3,746,730 ($5,553,167 x 67.47%) and capitalized pension expense of $1,806,437 ($5,553,167 x 32.53%) (Columbia Ex. No. 104, Sch. 2, p. 12).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on a three-year average of contributions to its pension trust (Columbia St. No. 4, pp. 14-15). The total pension expense was further allocated between pension expense and capitalized pension expense using ratios that correspond to the Company's payroll allocation.

Q. HOW DID THE COMPANY CALCULATE ITS TOTAL CLAIM?

A. The Company calculated total pension expense as follows (Columbia Ex. No. 104, Sch. 2, p. 12):

Contribution Year	Amount	
7/1/2011-6/30/2012	$15,020,000	
7/1/2012-6/30/2013	$0	
7/1/2013-6/30/2014	$1,624,500	(one-half of 2014 amount)
Subtotal	$16,644,500	
Divided by 3 Years	÷ 3	
3-Year Average	$5,548,167	
Plus Supplemental Retirement Income	$5,000	
	$5,553,167	

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING PENSION EXPENSE?

A. I recommend an allowance of $817,250 for total pension expense.

Q. HOW DID YOU CALCULATE THE RECOMMENDED ALLOWANCE FOR TOTAL PENSION EXPENSE?

A. My recommended allowance for total pension expense was calculated as follows (Columbia Ex. No. 104, Sch. 2, p. 12):

Contribution Year	Amount	
7/1/2012-6/30/2013	$0	
7/1/2013-6/30/2014	$1,624,500	(one-half of 2014 amount)
Subtotal	$1,624,500	
Divided by 2 Years	÷ 2	
2-Year Average	$812,250	
Plus Supplemental Retirement Income	$5,000	
Recommended Total	$817,250	

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In the Company's previous rate case filing (at Docket No. R-2010-2215623) it used a two-year average of contributions to determine its pension expense claim. In this filing, the Company has changed to a three-year average of contributions.

For the purpose of consistency, I am recommending a two-year average in calculating an allowance for pension expense. It appears that the Company's change to a three-year historic average was made simply to increase the Company's claim.

Q. DO YOU HAVE ANY CHANGES TO THE COMPANY'S ALLOCATION PERCENTAGES FOR EXPENSE AND CAPITALIZED PORTIONS OF PENSION EXPENSE?

A. Yes. I disagree with the Company's method used to calculate the expense percentage and capitalization percentage for employee labor and benefits that results in the Company using a capital percentage of 32.53% and an expense percentage of 67.47% (Columbia Ex. No. 4, Sch. 2, p. 7).

Q. WHAT METHOD DID THE COMPANY USE IN ARRIVING AT THESE ALLOCATION PERCENTAGES?

A. The Company used a five-year historic average of capital and expense percentages using the following years: 2007, 2008, 2009, 2010, and 2011.

Q. WITH WHICH PART OF THE COMPANY'S METHOD DO YOU DISAGREE?

A. The Company did not incorporate recent data from 2012 in its five-year historic calculation, and instead used older data from 2007.

Q. WHAT METHOD DO YOU RECOMMEND IN CALCULATING THE CAPITALIZATION AND EXPENSE PERCENTAGES?

A. I recommend that the Company eliminate 2007 from its five-year historic average and use the percentages from the end of the historic test period ended May 31, 2012. The inclusion of this more current data will provide a more accurate estimate.

Q. WHAT CAPITALIZATION AND EXPENSE PERCENTAGES DO YOU RECOMMEND?

A. I recommend a capitalization percentage for payroll and related benefits (including pension) of 34.12%, and an expense percentage of 65.88%.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDED CAPITALIZATION AND EXPENSE PERCENTAGES?

A. My capitalization percentage is calculated as follows (Columbia Ex. No. 4, Sch. 2, p. 7):

12/31/2008	33.9689%
12/31/2009	32.4915%
12/31/2010	29.9560%
12/31/2011	35.7192%
05/31/2012	38.4502%
Subtotal	170.59
Divided by 5 Years	÷ 5
5-Year Average	34.12%

The expense percentage was determined as follows: 100.00% – 34.12%, providing an expense percentage of 65.88%.

Q. USING YOUR RECOMMENDED PERCENTAGES, PLEASE STATE YOUR RECOMMENDED PENSION EXPENSE AND CAPITALIZED PENSION ALLOWANCE AMOUNTS.

A. My total pension expense recommendation of $817,250 can be further broken down as $538,404 ($817,250 x 65.88%), or a reduction of $3,208,326 ($3,746,730 - $553,404) to pension expense, and $278,846 ($817,250 x 34.12%), or reduction of $1,527,591 ($1,806,437 - $278,846) to capitalized pension expense.

PROFIT SHARING AND STOCK REWARDS

Q. EXPLAIN THE COMPANY'S PROFIT SHARING AND STOCK REWARDS BENEFITS.

A. The Company included profit sharing claims for direct employees and allocations from the NiSource Corporate Service Company ("NCSC"), the Company's affiliate service company. The employee benefit portion is included with other employee benefits (Columbia Ex. No. 104, Sch. 2, pp. 11-12).

Q. WHAT IS THE COMPANY'S CLAIM FOR PROFIT SHARING AND STOCK REWARDS?

A. For the purpose of this testimony, I have broken down the Company's FPFTY claim into three components: (1) direct employees' profit sharing; (2) direct employees' stock rewards; and (3) NCSC-allocated profit sharing and stock rewards. Each of these components is detailed below.

Direct Employees' Profit Sharing

The Company's total claim for direct employees' profit sharing is $343,759, which can be further broken down as $231,934 ($343,759 x 67.47%) in expenses and $111,825 ($343,759 x 32.53%) in capitalized profit sharing (Columbia Ex. No. 104, Sch. 2, p. 12).

Direct Employees' Stock Rewards

The Company has identified $139,296 in FPFTY stock rewards expense for direct employees included in labor costs, which consists of the following: contingent stock of $100,083; restricted stock of $20,406; and CEO stock grants of $18,807 (I&E Ex. No. 2, Sch. 7, p. 1). I have calculated the capitalized portion of $67,160 [($139,296 / 67.47%) x 32.53%] based on the Company's payroll factors (Columbia Ex. No. 104, Sch. 2, p. 1).

NCSC-Allocated Profit Sharing and Stock Rewards

The Company is claiming $1,018,707 in NCSC-allocated profit sharing and stock rewards expense as a part of System Services which can be broken down as follows (I&E Ex. No. 2, Sch. 8, p. 1):

Profit Sharing	$112,683
Phantom Stock	101,981
Contingent Stock	633,387
Restricted Stock	114,310
CEO Stock Grants	56,346
Total Expense	$1,018,707

In addition, the Company has capitalized an additional $27,942 for profit sharing (I&E Ex. No. 2, Sch. 9).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR PROFIT SHARING AND STOCK REWARDS?

A. No.

Q. WHAT DO YOU RECOMMEND FOR PROFIT SHARING AND STOCK REWARDS?

A. Based on the above headings, I recommend that the Company's entire claim for direct employees' profit sharing expense ($231,934), capitalized direct employees' profit sharing ($111,825), direct employees' stock rewards expense ($139,296), direct employees' capitalized stock rewards ($67,160), NCSC-allocated profit sharing and stock rewards expense ($1,018,707), and NCSC-allocated capitalized profit sharing ($27,942), or a total of $1,596,864 be denied.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company has indicated that the profit sharing benefit is based on NiSource meeting its earnings per share goal (I&E Ex. No. 2, Sch. 10, p. 2). These payouts appear to be made independent of quality of service, efficiency, or safety goals of Columbia. Furthermore, the stock rewards are only available to top level NiSource employees (I&E Ex. No. 2, Sch. 8, p. 2). Ratepayers should not be obligated to pay for an expense that is based only on earnings goals and is unrelated to the provision of safe and reliable service.

RENTS AND LEASES

Q. WHAT IS INCLUDED WITH RENTS AND LEASES?

A. The Company's claim for rents and leases is broken down between rents and leases for buildings and other rents and leases for communications equipment and lines, office machines, and furnishings (Columbia St. No. 4, pp. 20-21).

Q. WHAT IS THE COMPANY'S CLAIM FOR RENTS AND LEASES?

A. The Company is claiming $1,677,551 for rents and leases (Columbia Ex. No. 104, Sch. 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company analyzed rents and leases and made adjustments to annualize those that will be in effect during the FPFTY (Columbia St. No. 4, p. 21, lines 2-10).

Q. HAS THE COMPANY IDENTIFIED ANY CHANGES TO ITS ORIGINAL CLAIM?

A. Yes. In preparing a response to I&E-RE-96-D the Company identified a revision to its Exhibit No. 4, Schedule 2, p. 8, and Exhibit No. 104, Schedule 2, p. 15. It was necessary to update Lease 3611 for the Bursca 79 South Office (I&E Ex. No. 2, Sch. 11, pp. 4-5, line 9). This update caused a reduction to the Company's original rents and leases expense claim of $33,699 (I&E Ex. No. 2, Sch. 11, p. 2), which reduces the Company's FPFTY claim to $1,643,852 ($1,677,551 - $33,699).

Q. DO YOU ACCEPT COLUMBIA'S UPDATED CLAIM FOR RENTS AND LEASES?

A. Yes.

<u>SYSTEM SERVICES – BUSINESS PROMOTION SERVICES</u>

Q. WHAT IS SYSTEM SERVICES – BUSINESS PROMOTION SERVICES?

A. According to Company Witness Cogar, Business Promotion Services assists with the development of residential, commercial, and industrial business (Columbia St. No. 12, p. 9). Business Promotion Services is a service category containing items allocated to Columbia by NCSC.

Q. WHAT IS THE COMPANY'S CLAIM FOR SYSTEM SERVICES – BUSINESS PROMOTION SERVICES?

A. The Company is claiming a total of $2,079,833 for Business Promotion Services (Columbia Exhibit SDC-3). This amount can be further broken down between the expensed portion of $1,608,646, and the capitalized portion of $471,187 (I&E Ex. No. 2, Sch. 12, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company included the NCSC-allocated portions of labor and non-labor related Business Promotion Services costs (I&E Ex. No. 2, Sch. 12, p. 2).

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM FOR BUSINESS PROMOTION SERVICES?

A. No.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING SYSTEM SERVICES – BUSINESS PROMOTION SERVICES?

A. I recommend that the total claim amount of $2,079,833 be denied, which includes the expense portion of $1,608,646 and the capitalized portion of $471,187.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Costs to promote the Company's corporate image or to promote the use of natural gas, thereby promoting Columbia's business, are not necessary to provide safe and reliable utility service to the customers and therefore should not be paid for by the ratepayers.

INCENTIVE COMPENSATION – DIRECT EMPLOYEES

Q. WHAT IS INCENTIVE COMPENSATION – DIRECT EMPLOYEES?

A. The Company has included an incentive compensation claim for its direct employees. Incentives are dependent on individual employee performance goals (Columbia St. No. 4, p. 12). However, according to Company Witness Gore, the incentive plan does not provide a payout if NiSource does not meet incentive plan targets for the year (Columbia St. No. 4, p. 13).

Q. WHAT IS THE COMPANY'S CLAIM FOR INCENTIVE COMPENSATION?

A. The Company is claiming $2,047,906 which can be further broken down between incentive compensation expense of $1,381,722 ($2,047,906 x 67.47%) and capitalized incentive compensation of $666,184 ($2,047,906 x 32.53%) (Columbia Ex. No. 104, Sch. 2, p. 4).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company based its claim on expected incentive payments at target levels for the FPFTY (Columbia St. No. 4, p. 13).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR INCENTIVE COMPENSATION?

A. No.

Q. WHAT AMOUNT DO YOU RECOMMEND?

A. I recommend a total allowance for incentive compensation of $1,023,953. This amount is further broken down by applying the adjusted capitalized and expense percentages (34.12% and 65.88% respectively) as discussed in my pension expense recommendation previously in this testimony. I am recommending incentive compensation expense of $674,580 ($1,023,953 x 65.88%), or a reduction of $707,142 ($1,381,722 - $674,580). Additionally, I am recommending capitalized incentive compensation of $349,373 ($1,023,953 x 34.12%), or a reduction of $316,811 ($666,184 - $349,373).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My overall adjustment to total incentive compensation results from two main changes: first, a reduction to the portion of the benefit paid by ratepayers; and second, an adjustment to reflect my recommended change to the expensed and capitalized percentages, as discussed previously in this testimony.

Q. EXPLAIN IN MORE DETAIL THE BASIS OF YOUR ADJUSTMENT THAT REDUCES THE PORTION OF INCENTIVE COMPENSATION TO BE FUNDED BY RATEPAYERS.

A. Company Witness Gore indicates that if the NiSource earnings per share target is not achieved, no amount is paid for that particular factor, and that the Business Unit Performance payout is reduced by 50%. Furthermore, he indicates that, for exempt employees, the incentive payout opportunity is two-thirds discretionary and one-third non-discretionary, with the discretionary portion based on performance management (I&E Ex. No. 2, Sch. 13, p. 3). In other words, the Company pays a substantially reduced incentive compensation payout if individual goals are met but the NiSource earnings per share target is not met. Under these circumstances, where such a large emphasis is based on NiSource's earnings per share targets, I am recommending that shareholders and ratepayers share equally in the cost of this benefit.

SYSTEM SERVICES – INCENTIVE COMPENSATION

Q. WHAT IS SYSTEM SERVICES – INCENTIVE COMPENSATION?

A. The Company has included an 11.22% allocation to Columbia from NCSC for incentive compensation (Columbia Ex. No. 104, Sch. 2, p. 23). This 11.22% allocation is in line with the NCSC payroll allocation.

Q. WHAT IS THE COMPANY'S CLAIM FOR SYSTEM SERVICES – INCENTIVE COMPENSATION?

A. The Company is claiming a total of $2,333,589 for the NCSC-allocated share of incentive compensation calculated as follows:

FTY	$2,203,629	Columbia Ex. No. 104, Sch. 2, p. 23
+ FPFTY Adj.	129,960	Columbia Ex. SDC-3
Total	$2,333,589	

	x <u>80.13%</u>	Columbia Ex. No. 104, Sch. 2, p.23
Expensed	<u>$1,869,905</u>	
Total	$2,333,589	
	x <u>19.87%</u>	Columbia Ex. No. 104, Sch. 2, p. 23
Capitalized	<u>$463,684</u>	

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company based its claim on expected incentive payments at target levels for the FPFTY (Columbia St. No. 4, p. 13).

Q. WERE THERE ANY ERRORS ON THE COMPANY'S SCHEDULES THAT INCLUDE THE CALCULATION FOR ITS SYSTEM SERVICES – INCENTIVE COMPENSATION CLAIM?

A. Yes. The Company indicated that the label on its Exhibit No. 104, Schedule 2, p. 23 displayed system services – incentive compensation incorrectly as "Accrued Bonus and Profit Sharing" (I&E Ex. No. 2, Sch. 14).

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM FOR SYSTEM SERVICES – INCENTIVE COMPENSATION?

A. No.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING SYSTEM SERVICES – INCENTIVE COMPENSATION?

A. I recommend an allowance of $934,952 for the expensed portion of system services – incentive compensation, or a reduction of $934,953 ($1,869,905 - $934,952), and a capitalized amount of $231,842, or a reduction of $231,842 ($463,684 - $231,842).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommend that the NCSC-allocated incentive compensation amounts (capitalized and expensed) be shared equally between shareholders and ratepayers for the same reason I discussed in my recommendation for the direct employees' incentive compensation costs. Where such a large emphasis is based on NiSource's earnings per share targets, I recommend that shareholders and ratepayers share equally in the cost of this benefit.

<u>LABOR</u>

Q. WHAT IS INCLUDED IN LABOR?

A. The labor category includes labor costs for the Company's 510 active employees as of May 2012 (Columbia St. No. 4, p. 8). This account includes salaries/wages, profit sharing, and stock rewards (I&E Ex. No. 7, p. 2).

Q. WHAT IS THE COMPANY'S CLAIM FOR LABOR?

A. The Company is claiming labor expense of $26,668,606 (Columbia Ex. No. 104, Sch. 1, p. 2). For the purposes of this recommendation, I am excluding profit sharing and stock rewards that I recommend denial of in a previous section of this testimony. Thus, labor expense net of profit sharing is calculated as follows:

Labor Expense	$26,668,606
Less Profit Sharing	(231,934)
Less Stock Rewards	(139,296)
Labor net of Profit Sharing And Stock Rewards	$26,297,376

Based on the above calculation, total labor net of profit sharing and stock rewards is $38,976,398 ($26,297,376 ÷ 0.6747), and capitalized labor net of profit sharing and stock rewards is $12,679,022 [($38,976,398 x 32.53%].

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR LABOR NET OF PROFIT SHARING AND STOCK REWARDS?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend labor expense allowance of $25,677,651 ($38,976,398 x 65.88%), or a reduction of $619,725 ($26,297,376 - $25,677,651). Additionally, I recommend a capitalized labor allowance of $13,298,747 ($38,976,398 x 34.12%), or an increase of $619,725 ($13,298,747 - $12,679,022).

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. I do not recommend any changes to total labor net of profit sharing and stock rewards. My recommendation relates only to the allocation of labor between expensed and capitalized amounts. This change was the result of using more current data in the five-year historic average used to calculate the expensed and capitalized portions of labor costs as discussed previously in the pension section of this testimony (pp. 15-17).

EMPLOYEE INSURANCE PLANS & THRIFT PLAN – ACTIVE EMPLOYEES AT MAY 2012

Q. WHAT IS INCLUDED IN EMPLOYEE INSURANCE PLANS & THRIFT PLAN?

A. For purposes of this testimony, I am combining insurance plans and the Company's thrift plan into one category. The items included here are the Company's medical insurance, employee assistance plan ("EAP"), dental, group life, long term disability, and the thrift plan. These are all benefits provided by the Company to its employees that are allocated between expense and capitalized portions. It should also be noted here that my adjustment relates only to the expense and capitalized allocation for the cost associated with the Company's (510) active employees at May 2012.

Q. WHAT IS THE COMPANY CLAIMING FOR ITS ACTIVE EMPLOYEES' INSURANCE PLANS AND THE THRIFT PLAN?

A. The Company is claiming the following amounts (Columbia Ex. No. 104, Sch. 2, p. 12):

Benefit	Expense	Capitalized
Medical Insurance & EAP	$3,092,150	$1,490,850
Dental Assistance	$217,928	$105,072
Group Life Insurance	$79,615	$38,385
Long Term Disability	$201,061	$96,939
Thrift Plan	$1,199,617	$578,383
Total	$4,790,371	$2,309,629

Thus, total employee insurance plans and thrift plan costs for existing employees is $7,100,000 ($4,790,371 + $2,309,629).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR EXISTING EMPLOYEES' INSURANCE PLANS AND THE THRIFT PLAN?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an expense allowance of $4,677,480 ($7,100,000 x 65.88%), or a reduction of $112,891 ($4,790,371 - $4,677,480) to the Company's claim. Additionally, I recommend a capitalized amount of $2,422,520 ($7,100,000 x 34.12%), or an increase of $112,891 ($2,422,520 - $2,309,629) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I am basing this recommendation on the previously recommended adjustment to the capitalized and expense percentages discussed in the pension section of this testimony (pp. 15-17).

PAYROLL TAXES – DIRECT EMPLOYEES

Q. WHAT ARE PAYROLL TAXES – DIRECT EMPLOYEES?

A. Payroll taxes – direct employees encompasses the Company's share of employee payroll taxes for direct employees, including FICA, Federal Unemployment, and State Unemployment (Columbia Ex. No. 106, Sch. 2, p. 2).

Q. WHAT IS THE COMPANY'S CLAIM FOR PAYROLL TAXES – DIRECT EMPLOYEES?

A. The Company is claiming a total of $2,190,870 for direct employees' payroll taxes. This can be further broken down as $1,617,921 ($2,190,870 x 67.47%) for payroll tax expense, and $780,065 ($2,190,870 x 32.53%) for capitalized payroll taxes based upon the Company's expensed and capitalization percentages of 67.47% and 32.53% respectively (Columbia Ex. No. 106, Sch. 2, p. 2, and Columbia Ex. No. 104, Sch. 2, p. 1, line 13).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has included a payroll tax claim for tax amounts that correspond to its FPFTY claims for labor (payroll) and incentive compensation (Columbia Ex. No. 104, Sch. 1, p. 2, lines 1 and 2).

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM FOR PAYROLL TAXES FOR DIRECT EMPLOYEES?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend payroll tax expense of $1,514,123, or a reduction of $103,798 ($1,617,921 - $1,514,123), and capitalized payroll taxes of $802,608, or an increase of $22,543 ($802,608 - $780,065) (I&E Ex. No. 2, Sch. 15).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company's labor and incentive compensation are subject to the Company's share of payroll taxes. When an adjustment is made to these areas, it is necessary to make a corresponding adjustment to the Company's share of payroll taxes that are expensed and capitalized. Since I have recommended adjustments to the Company's labor and incentive compensation (expensed and capitalized) for direct employees, it is necessary for me to make the corresponding adjustments to expensed and capitalized payroll taxes (I&E Ex. No. 2, Sch. 15). I have utilized the Company's Payroll Tax to Labor Percentage of 7.92% as a basis for my calculation (Columbia Ex. No. 104, Sch. 2, p. 29, line 10).

SYSTEM SERVICES - PAYROLL TAXES

Q. WHAT IS SYSTEM SERVICES – PAYROLL TAXES?

A. System services – payroll taxes includes the payroll taxes on all labor-related costs subject to payroll taxes that have been allocated from NCSC to Columbia.

Q. WHAT IS THE COMPANY'S CLAIM FOR SYSTEM SERVICES – PAYROLL TAXES?

A. The Company is claiming a total of $1,138,686 NCSC-allocated payroll taxes. This amount can be further broken down as $912,429 in NCSC-allocated payroll tax expense and $226,257 in NCSC-allocated capitalized payroll taxes.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company included a payroll tax claim that corresponds to its allocated payroll and taxable benefits.

Q. HOW IS THE COMPANY'S CLAIM CALCULATED?

A. Total payroll taxes were determined by multiplying the Company's projected total gross monthly payroll taxes of $92,075 by 12 months to arrive at $1,104,900, and adding the payroll tax increase (associated with merit increases) of $33,786. This provides the total payroll tax claim of $1,138,686 ($1,104,900 + $33,786) (Columbia Ex. No. 104, Sch. 2, p. 29).

The amount can be further broken down to the expensed and capitalized portions by multiplying the Company's factors for expensed and capitalized payroll as follows (Columbia Ex. No. 104, Sch. 2, p. 29):

$1,138,686 x 80.13% = Payroll tax expense of $912,429

$1,138,686 x 19.87% = Capitalized payroll taxes of $226,257

Q. DO YOU AGREE WITH COLUMBIA'S CLAIM FOR SYSTEM SERVICES – PAYROLL TAXES?

A. No.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING SYSTEM SERVICES – PAYROLL TAXES?

A. I recommend an NCSC-allocated payroll tax expense of $838,381, or a reduction of $74,048 ($912,429 - $838,381), and an NCSC-allocated capitalized payroll tax amount of $207,895, or a reduction of $18,362 ($226,257 - $207,895) (I&E Ex. No. 2, Sch. 15).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I am adjusting payroll tax expense and capitalized payroll taxes for the corresponding payroll taxes associated with my recommended reduction to NCSC-allocated incentive compensation. In determining taxes associated with the recommended incentive compensation reductions I used the Company's Payroll Tax to Labor Percentage of 7.92% (Columbia Ex. No. 104, Sch. 2, p. 29, line 10). If incentive compensation is reduced by one-half as I have recommended, this corresponding reduction to payroll taxes is also necessary.

OTHER ISSUES

Q. AS THE FIRST CASE TO BE FILED UNDER ACT 11 ALLOWING FOR THE USE OF A FULLY PROJECTED FUTURE TEST YEAR, DO YOU HAVE ANY OBSERVATIONS, SUGGESTIONS, RECOMMENDATIONS, OR COMMENTS TO OFFER?

A. Yes. At this point I simply want to highlight how in this case the Company did not reflect the period June 1-30, 2013 in any of the test year periods (i.e., historic test year ("HTY"), FTY, or FPFTY). The Company states that it followed Commission regulations in determining the HTY and FTY periods, and when it determined the FPFTY, the "interplay between Act 11 and the laws and regulations in effect prior to Act 11" created a one month gap between the FTY and the FPFTY (I&E Ex. No. 2, Sch. 16).

Q. ARE YOU AWARE OF ANY PROBLEMS CREATED IN THE COMPANY'S FILING AS A RESULT OF THE LACK OF INCLUSION OF JUNE 1-30, 2013 IN THE FTY OR FPFTY PERIODS?

A. No. I am not. However, I believe this is something the Commission should take into consideration when formulating the guidelines for future Company filings that use the FPFTY period. I believe that the periods should line up continuously and not skip a month (or more) when moving from one period to the next.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE USE OF A FPFTY PERIOD?

A. Yes. The Company is annualizing healthcare costs, employee wages, and other costs in the FPFTY for raises and cost increases that are anticipated to come into play at any point throughout the FPFTY period. In performing my analysis, I have treated the annualizations in the FPFTY in a similar manner to how I have historically treated annualizations in the FTY period prior to Act 11. In other words, I have accepted the Company's annualization of these costs and have not recommended adjustments for removal of annualizations. This allows the Company to collect expenses that it has not yet incurred on the date that rates go into effect. The enhanced revenue impact has been considered by I&E Witness Emily Sears in determining an appropriate rate of return in this proceeding (I&E St. No. 1).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Christine S. Wilson, CPA
Professional and Educational Background

Experience:
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
Fixed Utility Financial Analyst, Bureau of Investigation & Enforcement
February 2008 – Present: Responsible for review of operating and maintenance expenses for utility companies as a part of the evaluation and recommendation process for utility base rate and purchase gas cost filings, preparing related written testimony for cases, and testifying as an expert witness as necessary.

Prior Experience: Approximately fifteen years performing public, corporate, and nonprofit accounting.

Education/Certification:
Green Mountain College, Poultney, Vermont
Sustainable MBA Program, four credits earned, 2009-2010

Certified Public Accountant in Pennsylvania, since 2000

Pennsylvania State University, Middletown, Pennsylvania
Bachelor of Science, Professional Accountancy, 1995

Utility-Specific Training:
Institute of Public Utilities Advanced Regulatory Studies Program, Michigan State University, East Lansing, Michigan, October 7-10, 2008

NARUC Utility Rate School (conducted by NARUC's Committee on Water and the Institute of Public Utilities, Michigan State University), San Diego, California, May 11-16, 2008

Testimony Submitted:
Docket No. R-2008-2032689 – PAWC Coatesville Wastewater Operations
Docket No. R-2008-2042293 – Newtown Artesian Water Company
Docket No. R-2008-2046518 – Pike County Light & Power Company – Electric
Docket No. R-2008-2079675 – UGI Central Penn Gas, Inc.
Docket No. M-2009-2093215 – PECO Energy Company (EE&C Plan)
Docket No. M-2009-2093216 – PPL Electric Utility Corporation (EE&C Plan)
Docket No. M-2009-2123944 – PECO Energy Company (Smart Meter Plan)
Docket No. M-2009-2123945 – PPL Electric Utility Company (Smart Meter Plan)
Docket No. R-2009-2117532 – Penn Estates Utilities Inc. – Water testimony combined with Docket No. R-2009-2117740 – Penn Estates Utilities Inc. – Sewer
Docket No. R-2009-2132019 – Aqua Pennsylvania, Inc.
Docket No. R-2010-2161694 – PPL Electric Utilities Corporation
Docket No. R-2010-2166208 – PAWC Clarion Wastewater Operations
Docket No. R-2010-2166210 – PAWC Claysville Wastewater Operations
Docket No. R-2010-2166212 – PAWC Coatesville Wastewater Operations
Docket No. R-2010-2166214 – PAWC Northeast Wastewater Operations
Docket No. R-2010-2201702 – Peoples Natural Gas Company, LLC
Docket No. R-2010-2214415 – UGI Central Penn Gas, Inc.
Docket No. R-2011-2267958 – Aqua Pennsylvania, Inc.
Docket No. R-2012-2285985 – Peoples Natural Gas Company, LLC
Docket No. R-2012-2292082 – Peoples Natural Gas Company, LLC - 1307(f) Proceeding

I&E Exhibit No. 2
Witness: Christine Wilson, CPA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

Columbia Gas of Pennsylvania

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

Exhibit to Accompany

the

Direct Testimony

of

Christine Wilson

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

2-13-13
Hbg QR

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Consumer Advocate - Set 2

Question No. OCA II – 024:

Please provide a copy of the funding information provided by GTI as referenced on Page 20, lines 10 and 11 of Ms. Krajovic's Direct Testimony.

Response:

This response assumes the funding information to which this question refers is that noted on lines 6 through 8 on page 20 of Columbia Statement No. 6.

The GTI Operations Technology Development Program (OTD) is funded by gas utilities at a basic charge of 50 cents per customer (see OCA II-024 Attachment A - OTD Board of Directors Minutes), with a minimum charge of $150,000 per company (see OCA II-024 Attachment B regarding an amendment to the minimum level) and a maximum charge of $750,000 per company. Minimum charges are activated if the company has less than 300,000 meters and maximum charges are in effect if the company has more than 1,500,000 meters.

These levels have been determined by the OTD Board of Directors as an appropriate level of investment in operations R&D to ensure that critical safety, integrity, and other operations projects are able to be conducted.

OTD BOARD OF DIRECTORS POLICIES 2003-2007

MEMBERSHIP DUES LEVELS

Membership Funding Levels

The Board was asked to consider lowering the minimum funding levels to retain current small to medium sized LDCs and to attract new members. After discussion, the Board directed management to study the impact of establishing a variable minimum funding level based upon a potential member's size and to report to the Board at the next meeting. The Board ratified the current member funding formula of:
- $0.50 per meter,
- minimum annual dues of $250,000,
- maximum annual dues of $750,000, and
- no maximum annual dues level for pooled members. *(5/12/04)*

Membership Funding Formula

The Board had asked staff to prepare an analysis of the effects of lowering the minimum funding levels in order to retain current small to medium sized LDCs and to attract new members. Mr. Snedic presented three options.

1. Continue the existing funding formula with minimum dues of $250,000
2. Adapt a sliding scale formula with dues ranging from $150,000 to $250,000, and
3. Adapt a small company sliding scale formula, with dues ranging from $150,000 to $250,000. Exclude participation from pools and medium & large companies and pools would retain the existing $.50 per meter formula with a $250,000 minimum.

After discussion, the Board elected to retain the current formula but directed staff to encourage small companies to associate together to form pools similar to the American Public Gas Association Research Foundation (APGA RF) pool. *(11/10/04)*

MINUTES OF THE MEETING OF THE BOARD OF DIRECTORS FOR OPERATIONS TECHNOLOGY DEVELOPMENT, NFP

May 21, 2008

Executive Session:

Membership Update

Mr. Snedic discussed the current dues calculation structure for individual members and the process of aggregating smaller members to reach the minimum dues level. Several different mechanisms were discussed. It was first proposed that OTD lower the minimum dues paid by Members to $150,000 from $250,000. A discussion ensued regarding the pros and cons of such an action. Upon a motion duly made and seconded, the board voted to lower the minimum dues level to $150,000 from $250,000, effective for the fiscal year 2009.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-115-D:

Reference Columbia Statement No. 6, pp. 16-20 concerning Gas Technology Institute (GTI) Funding. Provide the following:

A. Copies of statements, invoices, and/or receipts for the most recent twelve months-worth of funding to support the Company's $207,674 claim;

B. A list of affiliated companies that are regulated utilities also contributing toward GTI funding, amounts paid in the HTY by each, and the supporting calculations used to determine each amount; and

C. A schedule showing the individual amounts contributed to GTI by Columbia, its corporate parent, and any and all affiliated companies for each of the years 2009, 2010 and 2011. In the Company's response include the basis for the determination of each amount.

D. A breakdown of the parent company's and affiliate companies' planned contributions for the future test year (FTY) and FPFTY along with methods used to determine each individual amount.

Response:

A. The basis for the $207,674 claim is the calculation of funding per ratepayer at the advised GTI level. 415,347 customers x $0.50 = $207,674. Please also refer to CPA response to OCA II-024.

B. Columbia Gas of Kentucky ("CKY") funds GTI annually at the fixed level of $300,000. The $300,000 funding is reflective of the Kentucky Public Service Commission's approval of CKY's collection of funds via base rates equal to the amount previously generated annually through CKY's prior FERC approved surcharge.

C.

	CPA	CKY
2009		$300,000
2010	$135,000	$300,000
2011		$300,000

D. Columbia Gas of Kentucky will continue to fund GTI in the amount of $300,000 annually.

Columbia Gas of Pennsylvania believes that funding R&D is a necessary and proper cost of doing business in pursuing technological efficiencies and developments to provide cost effective service. Since the benefits of the research accrue to the customers, decisions about levels of funding will be made within the overall context of cost recovery.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-117-D:

Reference Columbia Statement No. 6, p. 19, line 17 through p. 20, line 8 concerning GTI funding. Explain:

A. Any difference in the benefit received by Columbia as a result of the Company contributing less than it had originally planned ($165,000 versus the previously intended $207,674); and

B. Any minimum funding requirement by the Institute for a company to participate in the GTI Operations Technology Development (OTD) projects.

Response:

A. Technological advancements and improvements that come out of GTI's research are not discreet units that can be proportionally allocated among individuals or groups, based upon each entities' contribution. It is impossible to identify what benefits may have been generated by GTI's projects if the total dollars available to support research had been greater. The reduction in funding tends to slow down research as less resources can be assigned to projects that CPA prioritizes.

B. The cost to participate in the OTD research group is $0.50 per meter for participating companies. For CPA, that equates to the $207,674 originally planned.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Consumer Advocate - Set 2

Question No. OCA II – 006:

Please provide supporting documentation for the estimate of $2.02 million of non-recurring O&M costs associated with NiFIT. Include a breakdown of those costs according to type of expense (internal labor, external labor, travel costs, computer software and hardware, etc.).

Response:

The following is the breakdown of the $2.02 million estimate of non-recurring O&M Costs associated with NiFiT:

Internal Labor (including NCSC)	$281,286
External Labor	744,447
Non Labor*	994,141
Total:	$2,019,874

*Non-Labor is made up of the following:

Hardware & Software	$130,261
Travel	614,248
Rent	88,712
Other	160,920
Total:	$994,141

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Consumer Advocate - Set 2

Question No. OCA II – 008:

To the extent that incremental NiFIT O&M costs include internal labor, please explain how the determination was made that those costs would not otherwise have been incurred.

Response:

The incremental NiFiT costs included in the $2.02 million O&M estimate includes internal labor. In developing the estimate, it was assumed that any vacancies created by the transfer of employees to the NiFiT project would be filled by replacement employees.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-127-D:

Reference Columbia Statement No. 4, p. 36, line 16 through p. 37, line 3 concerning odorization expense.

A. Provide the account name and dollar amount for the HTY costs incurred via the Company's upstream supplier.

B. Provide a breakdown of annual upstream supplier costs for 2007, 2008, 2009, 2010, and 2011.

C. Indicate where in the Company's filing the HTY upstream supplier costs were removed since the Company is taking the $75,000/year activity in-house.

D. Provide documentation to support the $75,000 cost estimate that was determined by the Company's engineering group.

E. Provide a breakdown of the $75,000 estimate.

F. Identify any costs in Part E above that are one-time in nature.

Response:

Out of the six upstream suppliers that Columbia contracts with for city gate capacity, one such upstream supplier has historically odorized all gas prior to Columbia taking ownership of the gas at the city gate. The odorization of that upstream supply is not a contractual or tariff obligation on part of the upstream supplier, but rather a result of historical operating practices, processes and pipeline configurations.

Now, as a result of changing supply dynamics it is Columbia's understanding that the influx of Appalachia shale supply has prompted a modification in the upstream supplier's pipeline operations. As a result of this reconfiguration, operations in certain geographic areas of the upstream pipeline are affected. Because the upstream supplier has no obligation to continue providing odorization services in those areas, Columbia will incur incremental O&M expense to accommodate this change in the upstream supplier's operations. Moreover, Columbia has worked with the upstream supplier to identify the impacted areas on Columbia's system, so that Columbia could minimize the expense associated with taking over some of the odorization responsibilities currently provided by the upstream supplier. At the present time, the upstream supplier will continue to odorize the majority of its delivery points while Columbia takes over responsibility for odorizing the six impacted areas. Columbia already incurs some odorization expense in base rates for areas it currently odorizes—as noted earlier, Columbia odorizes the supplies received from all other upstream suppliers.

A. The costs incurred by the upstream supplier are not identifiable because they are embedded in the upstream supplier's overall transportation rates charged to all of its shippers. These embedded odorization costs are recovered from Columbia's customers in the gas cost recovery mechanism.

B. Columbia cannot provide this information. See part A of this response.

C. No historic test year adjustment is needed. The costs Columbia will incur to odorize the areas where the upstream supplier will cease its odorization activities are incremental for the reasons already explained in this response. As also noted earlier, the Company does have limited odorization equipment currently in service, and that equipment will continue to remain in service.

D. The cost estimate is based on historic cost of operating and maintaining existing odorizers owned and operated by Columbia. See I&E-RE-127-D Attachment A. The new estimate of $60,746 reflects expected costs to maintain and operate six odorizer units. This has been revised down from the seven units used to develop the original claim. The

Company will reflect this updated expense in its final updated claim in this case.

E. See I&E-RE-127-D Attachment A for the breakdown in O&M cost for seven additional odorizers.

F. One-time costs were not included in the estimate. However, there will be additional O&M costs for odorizing farm taps that are not included in this case.

Annual Operation Of Odorization | **Annual Maintenance Of Odorization**

3 YEAR AVERAGE 2009-2011	TOTAL		3 YEAR AVERAGE 2009-2011	TOTAL	Estimated Odorizer O&M Cost
Historical Cost per Unit Materials	$54.31		Historical Cost per Unit Materials	$5,619.77	
Historical Cost per Unit Outside Serv	$16.66		Historical Cost per Unit Outside Serv	$0.00	
Historical Cost per Unit Other	$27.47		Historical Cost per Unit Other	$4,406.30	
Historical Cost per Unit	$98.43		Historical Cost per Unit	$10,026.07	$60,746.99

Sum of Annual Operation and Maintenance x 6
odorizor units = $60, 746.99

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-31-D Revised:

Reference Exhibit 104, Schedule 1, p. 2 concerning inflation. Identify amounts for fixed leases, amortizations, or other costs known not to be subject to price increases from Column 3 and Column 6. Identify all such items by Line No./Account and dollar amount.

Response:

Exhibit 104, Schedule 1, page 2, line 19, Other O&M includes the annual amortization for Longwall Mining of $54,209.64.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-133:

Reference the Company's response to I&E-RE-31-D concerning the monthly amortization for Longwall Mining of $54,209.64.

A. Provide:

1. The original dollar amount;

2. The month and year the amortization began;

3. The annual amortization amount; and

4. The unamortized balance as of June 30, 2013.

B. Explain why this item is adjusted for inflation.

Response:

A.

1. The original dollar amount of the Longwall Mining was $266,189.

2. The month and year that the amortization began was October 2008.

3. The response to I&E-RE-31-D incorrectly indicated the monthly amortization for Longwall Mining was $54,209.64. The annual amortization is $54,209.64 and the monthly amortization would be 1/12th of this amount.

4. The unamortized balance as of June 30, 2013 will be $13,552.

B.

Given the amortization of this regulatory asset is almost complete at the beginning of the rate year, the annual amortization of $54,210 and the associated inflation adjustments related to this amount will be removed from the claim.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Consumer Advocate - Set I

Question No. OCA I – 011:

Please state whether any amounts are included in the HTY, FTY or FFRY for payments under any other incentive performance or stock reward plan other than the Corporate Incentive Compensation Plan described at pages 5-9 of Schedule No. 2 in Exhibit No. 104. If yes:

a. Identify the amounts included for each such plan or program in each year and explain where those amounts are reflected in Columbia's expenses;

b. Please identify the employees/employee groups eligible for each plan; and

c. Please provide the plan documents describing each plan and the basis upon which awards are paid.

Response:

A.

Please see Table A below for the Company amounts included in the HTY, FTY and FFRY for each incentive performance and stock reward plan other than the Corporate Incentive Compensation Plan.

Table A

Plan	HTY	FTY	FFRY
Profit Sharing	341,334	225,490	31,934
Contingent Stock	100,083	100,083	100,083
Restricted Stock	20,406	20,406	20,406
CEO Stock Grants	18,807	18,807	18,807

The HTY profit sharing amount is included in the claim as part of Other Benefits at Exhibit No. 4, Schedule No. 1, Page 2, Line 6. The FTY and FFRY profit sharing amount are included in the claim as part of Other Benefits at Exhibit No. 104, Schedule No. 1, Page 2, Line 6.

The HTY Contingent Stock, Restricted Stock and CEO Stock Grants are included in the claim as part of Labor at Exhibit No. 4, Schedule No. 1, Page 2, Line 1. The FTY and FFRY amounts are included at Exhibit No. 104, Schedule No. 1, Page 2, Line 1.

B & C.

The plans and eligibility information are provided in response to OCA-I-12.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Consumer Advocate - Set I

Question No. OCA Set I – 012:

Please provide the same information requested in the prior question with regard to the Incentive Compensation amounts included in NiSource Corporate Service Company (NCSC) billings.

Response:

a. Please see Table A below for the NiSource Corporate Services Company (NCSC) amounts included in the HTY, FTY and FFRY for each incentive performance and stock reward plan other than the Corporate Incentive Compensation Plan. The HTY amounts are reflected in Columbia's expenses in Exhibit No. 4, Schedule 1, Page 2, Line 25 as System Services. The FTY and FFRY expenses are reflected in Exhibit No. 104, Schedule 1, Page 2, Line 25 as System Services.

Table A

Plan	HTY	FTY	FFRY
Profit Sharing	131,965	107,493	112,683
Phantom Stock*	98,591	100,415	101,981
Contingent Stock**	612,330	623,658	633,387
Restricted Stock**	110,510	112,554	114,310
CEO Stock Grants**	54,472	55,480	56,346

* Phantom Stock was awarded as a result of a change in control of the company, and was not issued pursuant to a plan.

**The Contingent Stock, Restricted Stock, and CEO Stock Grants are equity awards issued under the 2010 Omnibus Incentive Plan and its predecessor, the 1994 Long Term Incentive Plan.

b. Please reference GAS-RR-024 Attachment E for details concerning profit sharing eligibility pursuant to the NiSource Retirement Savings Plan, I&E-

RE-46 Attachment A for a copy of the 2010 Omnibus Incentive Plan ("Omnibus Plan") which governs Contingent, Restricted and CEO Stock Grants, and OCA I-012 Attachment A for the 1994 Long-Term Incentive Plan. Each plan identifies the employees/employee groups eligible for each plan. Grants of contingent and restricted stock are made to certain employees at the level of Vice President and above. CEO Stock Grants are issued in the form of restricted stock units and are available to select exempt employees. For Phantom Stock eligibility, see the "Phantom Units" section on page 43 of the proxy statement, OCA I-012 Attachment B. Only three current NiSource Corporate Services Company executives were issued Phantom Stock.

c. Please see GAS-RR-024 for a copy of the NiSource Retirement Savings plan. See I&E-RE-46 Attachment A for the Omnibus Plan and OCA I-012 Attachment A for the 1994 Long-Term Incentive Plan. Profit Sharing awards are paid based upon the achievement of a trigger, target, or stretch earnings per share goal. This is the same earnings per share goal as found in the Corporate Incentive Plan. The Executive Compensation Discussion and Analysis portion (pages 20-32) of the annual proxy, Attachment B to this response, starts by highlighting NiSource Inc.'s 2011 Executive Compensation Program, and outlines key terms and conditions of equity grants described above to Named Executive Officers. Phantom Stock is discussed on page 43 of Attachment B to this response, which describes the basis for which Phantom Stock will be paid.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-176:

Reference Columbia's response to OCA-I-012 concerning NCSC-allocated profit sharing and stock rewards. Provide a breakdown of expensed and capitalized portions of the following fully projected future test year amounts (identified as FFRY on the response). If the amounts below are 100% expensed, identify the corresponding capitalized portions for each, where applicable.

Profit Sharing	$112,683
Phantom Stock	$101,981
Contingent Stock	$633,387
Restricted Stock	$114,310
CEO Stock Grants	$56,346

Response:

The amounts noted reflect the amounts charged to expense.

In addition to the above expense amounts, there was $27,942 of profit sharing costs charged to capital.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation & Enforcement - Set RE

Question No. I&E-RE-62-D:

Reference Exhibit 104, Schedule 2, p. 12 concerning the Profit Sharing Plan. Provide:

A. An explanation of the detailed eligibility requirements;

B. Identification of the individual employees by title who are eligible for each benefits;

C. An explanation why adding new employees would result in increased expensed/capitalized claim amounts.

D. Copies of Plan documents and any other available documentation that details eligibility requirements.

E. The dollar amount (expensed and capitalized) attributable solely to meeting financial performance goals.

F. An explanation whether it is correct that the financial goals or triggers must be met before any profit sharing plan benefits are paid. If not, identify the portion of each benefit that is paid independent of whether financial goals are met.

Response:

Attachment E in response to GAS-RR-024 is a copy of the NiSource Retirement Savings Plan. Within this plan, there are two distinctive benefit programs (1) thrift plan and (2) profit sharing plan. The responses in this response reflect the profit sharing program and the response to I&E-RE-61-D reflects the thrift plan program.

Questions A,B & D,

Refer to Attachment E in response GAS-RR-024, Page 7 of 61.

Question C:

Refer to Attachment E in response GAS-RR-24, Page 39 & 40 of 61. Exempt employees hired after January 1, 2010 are eligible for participation.

Refer to Attachment E in response GAS-RR-24, Page 41 of 61. Union employees hired after January 1, 2008 are eligible for participation.

All 55 new employees are automatically enrolled and eligible to receive the profit sharing benefit.

Questions E & F:

The total profit sharing benefit is paid based on NiSource meeting an Earnings Per Share goal.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-96-D:

Reference Columbia Statement No. 7, p. 12, lines 8-12, Exhibit RMK-1, and Exhibit No. 104, Schedule 2, p. 15 concerning leases.

A. Identify the leases/facilities to which Witness Kitchell is referring when referencing the "leases expiring on multiple Columbia building sites." Include the annual rent cost and square footage for the expiring leases.

B. Provide detailed justification for any increase in square footage at the new Alpine Point OP Center.

C. Provide a copy of the Alpine Point OP Center Lease.

Response:

While developing the response to this data request, it was determined that a correction is needed in the Rents and Leases information provided in Exhibit No. 4, Schedule No. 2, Page 8 of 27 and Exhibit No. 104, Schedule No. 2, Page 15 of 31. I&E-RE-96-D Attachment B provides revised rents and leases information for these two pages. The lease costs for the Bursca 79 South Office (Line 9) were reported in Line 9 and line 19 in the historic test year in the original claim.

In page 1 of I&E-RE-96-D Attachment B, line 9 has been revised and line 19A and 19B have been added. Lease 3611, detailed on Line 9, has been updated to reflect the full year-monthly rental for the Bursca 79 South Office space. During the test year, a portion of the rental costs for this building were classified to a different code and reflected in the Non-Building Leases expense detailed in Line 19. Lines 19A and 19B were added to remove costs for this building as Line 9 reflects the annual building costs.

The impact of this adjustment is the normalized historic test year adjustment should have been ($128,674) instead of the ($94,748) provided in Exhibit No. 4 in the original filing.

In page 2 of I&E-RE-96-D Attachment B, Line 20 has been updated to reflect the new HTY building lease cost. The revised FTY adjustment to Rents and Leases in Exhibit No. 104 is $340,522 and replaces the original FTY claim adjustment of $374,221.

As a result of these corrections, the claim for rents and leases is reduced by $67,625 as follows:

	Original Filing	Adjusted	Net Change
HTY Adjustment	(94,748)	(128,674)	(33,926)
FTY Adjustment	374,221	340,522	(33,699)
Net Adjustment			(67,625)

A. The two leases that expire are noted on I&E-RE-96-D Attachment B, Page 2, Lines 5 and 9. The costs for these two leases have been removed from the claim as noted by the $0 costs in the Column 6 (Annual Rental). Further details regarding these two leases are as follows:

Facility	Lease Expiration Date	Monthly Lease Cost before capitalization and intercompany billings	Square Feet
Bethel Park Annex 150 Hillside Drive Bethel Park, PA	July 24, 2012 August 31, 2012*	$6,249.24 $2350.00*	6492
Bursca 79 South 600 Bursca Drive Bridgeville, PA	August 31, 2012	$7709.45	6000

*As a result of a delay in construction of Alpine Point, the lease for Bethel Park had to be amended to add an extra month to the expiration date. The rent for that one additional month was $2350.00.

B. The increased size (20,719 square feet) at the new location can be attributed to the need for additional space that was not available at either of the two previous locations. Such additional space includes an assembly room to accommodate all PA Central Operating Center staff at safety meetings, a larger warehouse space to accommodate materials and equipment to be stored indoors in lieu of outside, a training/work area, and some indoor parking space for trucks and equipment to be able to protect them from inclement weather for emergency response.

C. Please see Attachment A to this response for a copy of the Alpine Point lease and the first amendment to that lease. The first amendment occurred before Columbia occupied the Alpine Point facility

Columbia Gas of Pennsylvania, Inc.
Rents and Leases
Twelve Months Ended May 31, 2012

Line No.	Lease Number	Type of Property		Monthly Rental (1) $	Charged to Other Comp. (2) $	Charged to A/C 107 (3) $	Net Monthly Rental (4=1-2-3) $	Annualized Rental (5=4*12) $
		Building Leases						
1	171	Service Center, Ellwood, Pennsylvania		816	140	0	676	8,112
2	1691	Service Center, Charleroi, Pennsylvania	(1)	351	416	(16)	(49)	(588)
3	1701	Service Center, Rochester, Pennsylvania		1,112	0	0	1,112	13,344
4	2989	Service Center, New Castle, Pennsylvania		6,100	386	857	4,857	58,284
5	3531	Bethel Park, Pennsylvania	(1)	521	3,191	0	(2,670)	(32,040)
6	3584	Warehouse, York, Pennsylvania		4,306	0	0	4,306	51,672
7	3584	Area Office, York, Pennsylvania		20,683	7,238	3,877	9,568	114,816
8	3601	Area Office, Somerset, Pennsylvania		1,662	0	0	1,662	19,944
9	3611	Bursca 79 South, Pennsylvania		7,709	0	1,156	6,553	78,636
10	3675	Headquarters, Champion Way, Canonsburg, PA		47,089	29,196	0	17,893	214,716
11	3679	Harrisburg Offices - Harrisburg, Pa		1,080	0	0	1,080	12,960
12	3692	Greencastle Storage Facilities		800	0	0	800	9,600
13		Washington Office - Not Leased	(1)	0	489	0	(489)	(5,868)
14		Uniontown Office - Not Leased	(1)	0	29	0	(29)	(348)
15		Subtotal Leases - Net O&M Impact		92,229	41,085	5,874	45,270	543,240
				Annual Cost		Charged to A/C 107	Net Annual Cost	
16		Property Taxes		50,829	0	8,613	42,216	42,216
17		Total Normalized Building Lease Expense - twelve months ended 5-31-12 (Line 15 + Line 16)						585,456
18		Total Rents and Leases per Books						1,398,078
19		All other Non-Building Leases (CEs 4071,4072,4081,4090,4091)						753,250
19A		Area Office - Neville Island (Activity charged to CE 4090)						69,302
19B		Adjusted All other Non-Building Leases						683,948
20		Total Building lease expense per books (Ln 18 Less Line 19B)						714,130
21		Total Lease Adjustment (Line 17 less Line 20)						(128,674)

(1) - Billings to affiliates include more items than just rent and for those buildings cause the net cost to be negative

Columbia Gas of Pennsylvania, Inc.
Rents and Leases
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forecasted Rate Year Period Ended June 30, 2014

Line No.	Lease Number	Type of Property	Monthly Rental (1) $	Adjust Monthly Rental (2) $	Charged to Other Comp. (3) $	Charged to A/C 107 (4) $	Net Monthly Rental (5=1+2-3-4) $	Annual Rental (6=5*12) $
		Building Leases						
1	171	Service Center, Ellwood, Pennsylvania	816		140	0	676	8,112
2	1691	Service Center, Charleroi, Pennsylvania	351		416	(16)	(49)	(588)
3	1701	Service Center, Rochester, Pennsylvania	1,112		0		1,112	13,342
4	2989	Service Center, New Castle, Pennsylvania	6,100		386	857	4,857	58,284
5	3531	***** Bethel Park, Pennsylvania	0					0
6	3584	Warehouse, York, Pennsylvania	4,306				4,306	51,672
7	3584	Area Office, York, Pennsylvania	20,683		7,238	3,877	9,568	114,816
8	3601	Area Office, Somerset, Pennsylvania	1,662				1,662	19,944
9	3611	***** Bursca 79 South, Pennsylvania	0				0	0
10	3675	Headquarters, Champion Way, Canonsburg, PA	47,089		29,196		17,893	214,716
11		Headquarters, Champion Way, Canonsburg, PA	13,671		11,513		2,158	25,896
12	3679	Harrisburg Offices - Harrisburg, Pa	1,080				1,080	12,960
13	3692	Greencastle Storage Facilities	800				800	9,600
14		Washington Office - Not Leased	0		489		(489)	(5,868)
15		Uniontown Office - Not Leased	0		29		(29)	(348)
16	3704	Alpine Point OP Center, Bridgeville, PA	35,241		5,139		30,102	361,224
17		Subtotal Leases - Net O&M Impact	132,911		54,546	4,718	73,647	883,762

Line No.		Annual Cost	Charged to A/C 107	Net Annual Cost	
18	Property Taxes	50,829	8,613	42,216	42,216
19	Building Least total (Line 17 + Line 18)				925,978
20	Building Lease Total twelve months ended 5/31/12				585,456
21	Total Building Lease Adjustment (Line 19 - Line 20)				340,522

NOTE: Bethel Park and Area Office in Neville moving into Alpine Point office
Alpine Point office Lease effective 8/1/12

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RE

Question No. I&E-RE-170:

Reference Columbia Exhibit SDC-3 concerning the fully projected future test year (FPFTY) Business Promotion Services amount of $2,079,833.

A. Provide a detailed breakdown by type, showing dollar amounts for each type of item included in this service category (similar to the Company's response to I&E-RE-105-D).

B. Add columns in the response to Part A above that show: (1) the capitalized portion of each line item, and (2) the expensed portion.

Response:

A. Please see Table A, column B below for a detailed breakdown by type, showing dollar amounts for each type of item included in this service category. The amounts for each expense type were derived by utilizing the actual historical test year divided by the total amount to arrive at a percentage of the total for each expense type in response I&E-RE-105. The fully projected future test year (FPFTY) amount includes projected costs; therefore, we used the actual historic test year information to project out the breakout by expense type.

B. Please see Table A, columns C and D for the capitalized and expensed portion of the projected Business Promotion Services. The amounts were derived by utilizing the actual historical test year capital and expense percentages in I&E-RE-171, which were 22.66% and 77.34%, respectively. The fully projected future test year (FPFTY) amount includes projected costs; therefore, we used the actual historic test year information to project out the breakout by capital and expense for each expense type.

	Table A			
	A	B	C	D
	Expense Type	FFRY Amount	Capitalized	Expensed
1	Advertising Services	82,661	-	82,661
2	Business Expenses	49,450	2,959	46,491
3	Charitable Contributions	-	-	-
4	Company Dues & Membership Dues	9,584	-	9,584
5	Consulting Services	13,730	1,251	12,479
6	Employee Dues & Memberships	981	-	981
7	Fees, Licenses and Permits	882	8	874
8	Fuel	17,472	295	17,177
9	Furniture & Equip Maintenance	679	-	679
10	IT Software & Hardware	14,981	-	14,981
11	Lease Expense	16,943	287	16,657
12	Meals and Entertainment	36,576	2,364	34,212
13	Miscellaneous	7,580	328	7,252
14	Moving Expense	0	-	-
15	Office Supplies	6,529	105	6,424
16	Operations Services	331	-	331
17	Other Outside Services	8,629	24	8,605
18	Postal and Postage Fees	1,266	-	1,266
19	Rebates	1,488	-	1,488
20	Labor Expense	1,791,676	460,959	1,330,718
21	Temporary Personnel Services	2,575	2,318	258
22	Training	5,278	244	5,034
23	Vehicle Maintenance	10,543	46	10,496
24	Total	2,079,833	471,187	1,608,646

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation & Enforcement - Set RE

Question No. I&E-RE-46-D:

Reference Columbia Statement No. 4, pp. 11-13 and Exhibit No. 104, Schedule 2, pp. 4-9 regarding incentive compensation. For the 2011 and the 2012 Performance Years, provide the following:

A. Copies of all Incentive Plan documents, including but not limited to those that include the terms and conditions of the plan(s).

B. Identification of each and every incentive plan target and the FPFTY amount expensed/capitalized attributable to each target;

C. A list of all the financial triggers and their specified minimum performance standard to be achieved in order for any incentive amounts to become payable under the incentive plan;

D. The number of the Company's eligible participants;

E. The positions held by the Company's eligible participants for each plan;

F. Copies of a representative Performance Management Worksheet from each eligible position level of the Company, marking the applicable position level on each worksheet provided; and

G. Confirmation whether it is correct that financial goals or triggers must be met before any incentive compensation is paid. If not, identify the portion of FPFTY incentive compensation expensed/capitalized that is paid independent of whether financial goals are met.

Response:

A. I&E-RE-46-D Attachments A, B, C and D should replace and update the Incentive Compensation Plan included in Exhibit No. 104, Schedule 2, pp. 5-9. Attachment A is the NiSource Inc. 2010 Omnibus Incentive Plan ("the Omnibus Plan"), and is the governing incentive plan document under which all cash-based incentives are granted. Pursuant to Article XI of the Omnibus Plan, Attachments C and D govern the cash-based incentive terms and conditions for 2011 and 2012, respectively, for non-covered officers. Pursuant to Article XIII of the Omnibus Plan, Attachment B governs the terms and conditions of cash-based incentive terms for covered officers solely for purposes of compliance with Internal Revenue Code Section 162(m). The 162(m) performance target is not used to determine actual awards for covered officers, rather the specific performance measures which apply to covered officers are discussed in the Proxy, which can be found as an attachment to OCA I-012. The adjustment described in Exhibit No. 104, Schedule 2, pp. 4-9 and Columbia Statement No. 4, pp.11-13 is specific to all cash incentives included in the case.

B. For 2011, the incentive plan goals were $1.30 net operating earnings per share for NiSource, $335 million NiSource Gas Distribution business unit operating earnings, and $438 million NiSource Gas Distribution business unit cash from operations.

   For 2012, the incentive plan goals are $1.45 net operating earnings per share for NiSource, $182 million NiSource Gas Distribution business unit net operating earnings, and $325 million NiSource Gas Distribution business unit funds from operations.

   The incentive plan goals are not yet determined for the 2013 and 2014 plan years

   The incentive included in the FPFTY period is $2,047,906 as provided on Exhibit No. 104, Schedule No. 2, Page 4, Line 6. The portion assigned to expense and included in the claim is $1,381,722 (Line 8). The difference, or $666,184, reflects the portion assigned to capital. This claim is based on the assumption the incentive plan goals are met at the target payout levels.

C. For 2011, the incentive plan triggers were $1.25 net operating earnings per share for NiSource, $328 million NiSource Gas Distribution business unit operating earnings, and $220 million NiSource Gas Distribution business unit cash from operations. Note that if the Corporation's NOEPS for the Performance Year is less than $1.25, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

For 2012, the incentive plan triggers are $1.40 net operating earnings per share for NiSource, $177 million NiSource Gas Distribution business unit net operating earnings, and $297 million NiSource Gas Distribution business unit funds from operations. Note that if the Corporation's NOEPS for the Performance Year is less than $1.40, no amount shall be payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

For exempt employees, the incentive payout opportunity is two-thirds discretionary and one-third non-discretionary. The discretionary portion of the incentive program is based on performance management linked to goals including customer, employee, process/capability, and financial goals for Columbia Gas. Performance management is executed through the annual evaluative process embodied in the Performance Management Worksheet ("PMW").

A Columbia Gas employee's PMW contains annual performance objectives and articulates the means of measuring the employee's progress in relation to the objectives established. Each employee is actively involved in the development of his or her PMW, with input from his or her supervisor, and the employee's progress is reviewed and discussed with the employee periodically throughout the year.

The use of the PMW process to establish goals to measure employees' performance against these goals is important in reinforcing the proper focus on key initiatives and goals designed to improve customer service and reinforce cost containment. Examples of goals which support improved customer service include: (1) Percent of priorities responded to in 60 minutes or less is 98% or greater; (2) Average response time for priority orders is less than or equal to 25 minutes; and (3) Percent of customer generated appointments met is >= 97%. Other goals which help keep employees safe and support cost containment include: (1) reduced preventable vehicle accidents; and (2) reduced on-the-job injury rates.

See answer "F" for copies of employee PMWs.

D. For 2011, 508 employees were eligible. For 2012, approximately 523 employees are eligible as of 9/30/12.

E. See I&E-RE-46-D Attachment E for a list of titles of all eligible employees in 2011 and 2012 as of 9/30/12.

F. See I&E-RE-46-D Attachments F through J for PMWs. There is one PMW attached to represent each level of the Company.

G. For 2011 and 2012, at least one incentive plan goal must be met in order for any incentive payout to occur. If the Corporation's NOEPS for the Performance Year is less than trigger, no amount is payable under the Program for NOEPS and amounts payable for Business Unit performance shall be reduced by fifty percent (50%).

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Consumer Advocate - Set I

Question No. OCA Set I – 037:

Please provide a breakdown of NCSC Incentive Compensation and Profit Sharing between those two programs for 2012, 2013 and 2014.

Response:

The amounts shown on Exhibit No. 4, Schedule No. 2, page 22 and Exhibit No. 104, Schedule No. 2, pages 23 and 28 represent NCSC incentive compensation only, and the column headers should not have included Profit Sharing in the title as there were no profit sharing adjustments made or included in the supporting calculation pages.

Table A

Total NCSC	Incentive Compensation	Profit Sharing
2012	$25,179,035	$1,512,959
2013	$19,640,192	$1,240,764
2014	$20,229,397	$1,298,489

2012 incentive compensation and profit sharing included in the historical test year.
2013 incentive compensation at 2013 projected target level; profit sharing included as a benefit expense at the 2013 projected target level.
2014 incentive compensation at 2014 projected target level; profit sharing included as a benefit at the 2013 projected target level.

DIRECT:

I&E Reduction to Direct Incentive Compensation Expense	$ (690,861)
I&E Reduction to Labor Expense net of Profit Sharing/Stock Rewards	$ (619,725)
Net Change	$ (1,310,586)
x Payroll tax factor	7.92% *
Reduction to Payroll Tax Exp.	$ (103,798)
I&E Reduction to Direct Incentive Compensation - Capitalized	$ (333,092)
I&E Increase to Capitalized Labor net of Profit Sharing/Stock Rewards	$ 617,725
Net Change	$ 284,633
x Payroll tax factor	7.92% *
Increase to Capitalized Payroll Taxes	$ 22,543

NCSC-ALLOCATED:

I&E Reduction to NCSC-Allocated Incentive Compensation Expense	$ (934,953)
x Payroll tax factor	7.92% *
Reduction to Payroll Tax Exp.	$ (74,048)
I&E Reduction to NCSC-Allocated Incentive Compensation - Capitalized	$ (231,842)
x Payroll tax factor	7.92% *
Reduction to Capitalized Payroll Taxes	$ (18,362)

*Columbia Ex. No. 104, Sch. 2, p. 29, line 10

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement - Set RE

Question No. I&E-RE-34-D:

Reference Columbia Statement No. 4, p. 3, lines 1-3 concerning the test year periods.

A. In which period, historic test year (HTY), future test year (FTY), or fully projected future test year (FPFTY), is the period June 1-30, 2013 included?

B. If June 1-30, 2013, is not reflected in any of the periods, explain why not.

C. Identify any period(s) that contains more than 12 months and explain why this is appropriate.

D. Explain why the time period June 1, 2011 through May 31, 2012 was chosen for the HTY instead of the period July 1, 2011 through June 30, 2012.

Response:

A. The period June 1-30, 2013 is not included in any of these periods.

B. Commission regulations regarding Information Furnished With the Filing of Rate Changes require the submission of data for 12 months ending not more than 120 days before the date of filing (52 Pa. Code § 53.52(b)(2)). In addition, data for a future test year is to be for the twelve month period immediately following the historic test year. (52 Pa. Code § 53.53). Thus, the HTY for Columbia's case filed on September 28, 2012 is the year ended May 31, 2012, and the FTY is the year ended May 31, 2013.

Projecting the full suspension period under 66 Pa.C.S. § 1308(d) for a general rate case filed on September 28, 2012, new rates that are implemented as a result of this case can be expected to be effective as of the end of June 2013. Act 11 defines the FPFTY as the 12-month period beginning with the first month that the new rates will be placed into effect after application of the full rate case suspension period. Thus, the one-month gap between the FTY and the FPFTY is a function of the interplay between Act 11 and the laws and regulations in effect prior to Act 11.

C. Each test year (historic, future and fully projected future) contains 12 months.

D. Please see the response to Subpart B, above.

I&E Statement No. 2-SR
Witness: Christine Wilson, CPA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Surrebuttal Testimony

of

Christine Wilson, CPA

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

2-13-13
Hbg

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christine Wilson. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission ("PUC") in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTINE WILSON WHO IS RESPONSIBLE FOR I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made in rebuttal testimony by Columbia Gas of Pennsylvania ("Columbia" or "Company") witnesses Nancy J. D. Krajovic, Jeffrey T. Gore, Joel L. Hoelzer, and Gregory L. Shoemaker concerning my recommendations for Gas Technology Institute ("GTI") expense, NiFIT expense, pension expense, profit sharing and stock rewards, system services – business promotion services, incentive compensation, labor, employee insurance plans and thrift plan, and payroll taxes.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2-SR contains information relating to my surrebuttal testimony.

GAS TECHNOLOGY INSTITUTE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING GTI EXPENSE.

A. In direct testimony, I recommended an allowance of $150,000, which is a reduction of $57,674 ($207,674 - $150,000) to the Company's claim. This is the established minimum charge GTI assesses per company (I&E Statement No. 2, p. 5 and I&E Ex. No. 2, Sch. 1, p. 3).

Even though participation in the GTI Operations Technology Development ("OTD") Program is voluntary, I believe there is value to ratepayers based upon Ms. Krajovic's claim that participation in this organization shares costs across a broader industry base and generally benefits gas consumers (Columbia St. No. 6, p. 16). However, the Company has not shown that its historic contributions are anywhere close to its claim, and the Company has not substantiated that payment of an amount above the minimum dues level provides a measurably higher level of benefit to ratepayers (I&E Ex. No. 2, Sch. 3).

Q. DID THE COMPANY SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO YOUR RECOMMENDATION FOR GTI EXPENSE?

A. Yes. Columbia Witness Krajovic responded to my recommended adjustment to GTI expense (Columbia St. No. 106-R, pp. 15-16).

Q. EXPLAIN COMPANY WITNESS KRAJOVIC'S RESPONSE TO YOUR RECOMMENDATION.

A. Ms. Krajovic disagreed with my recommended $150,000 allowance. She stated that the Company actually did contribute $165,000 in 2012 in addition to the $135,000 paid in 2010 (I&E Ex. No. 2, Sch. 2, p. 2). Further, she indicated that the $150,000 minimum contribution requirement was for member companies that have less than 300,000 meters and that Columbia's count far exceeds this number (Columbia St. No. 106-R, pp. 15-16). She opined that the Company's claim is more accurately based upon a fee of $0.50 per customer for its 415,347 customers.

Q. DO YOU AGREE WITH MS. KRAJOVIC?

A. No.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. The fact that the Company contributed $165,000 in 2012, $0 in 2011, $135,000 in 2010, and $0 in 2009 supports my recommendation for an allowance of $150,000. In some years the Company has contributed nothing to GTI, therefore, I believe that $150,000 is more than adequate to fund the Company's contributions to GTI's efforts. GTI has accepted contributions of $135,000 and $165,000 (in 2010 and 2012 respectively), and there has been nothing presented to indicate that $150,000 will be unacceptable going forward. Ms. Krajovic's assertion that the $150,000 minimum contribution is for members with less than 300,000 meters is not supported by the Company's own contribution history.

NiFIT EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING NiFIT EXPENSE.

A. In direct testimony, I recommended an allowance of $347,743 or a reduction of $662,257 ($1,010,000 - $347,743) for NiFIT Expense. My recommendation removed internal labor costs (I&E Ex. No. 2, Sch. 4) and incorporated a 5-year recovery that is more appropriate than the 2-year recovery proposed by the Company (I&E Statement No. 2, p. 8).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDED ADJUSTMENT TO NiFIT EXPENSE?

A. Yes. Company Witness Gore responded with additional information about the internal labor portion of NiFIT costs for which I was recommending disallowance. He stated that the related employees are expected to be in the NiFIT positions for approximately five years, and their previously held positions have been filled or are in the process of being filled. He also explained that the 2-year recovery is aligned with the following: rate case expense; the passback of a remaining tax refund; and the passback of the OPEB deferral (Columbia St. No. 104-R, p. 14).

Q. DO YOU AGREE WITH MR. GORE?

A. No. Mr. Gore's reasons for selecting a 2-year recovery are unrelated to the NiFIT project and the software system's expected useful life. The fact that internal employees are expected to work in their NiFIT positions for five years provides further support for my recommended 5-year recovery. This 5-year time period is also better matched with Columbia's share of the related capital asset ($4.037 million) (Columbia St. No. 13, p. 6).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. Based upon the updated information provided in rebuttal testimony by Mr. Gore, I am willing to accept the internal labor portion of the Company's claim; however, I continue to recommend a 5-year recovery. This results in an annual allowance of $404,000 ($2,020,000 total ÷ 5 years) or a reduction of $606,000 ($1,010,000 - $404,000) to the Company's claim.

PENSION EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING PENSION EXPENSE.

A. In direct testimony, I recommended an allowance for total pension expense of $817,250. Using my recommended capitalization and expense percentages of 34.12% and 65.88% (I&E St. No. 2, pp. 16-17), my pension expense recommendation of $817,250 was further broken down as $538,404 ($817,250 x 65.88%), or a reduction of $3,208,326 ($3,746,730 - $538,404) to pension expense, and $278,846 ($817,250 x 34.12%), or a reduction of $1,527,591 ($1,806,437 - $278,846) to capitalized pension expense (I&E St. No. 2, p. 17).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION FOR PENSION EXPENSE?

A. Yes. Company Witness Gore expressed disagreement with my method of using a 2-year average, and stated his belief that a 3-year average is more representative of ongoing pension costs (Columbia St. No. 104-R, p. 10). He explained that the Company's use of a 3-year average provides a result that is in the middle of the different 2-year average methods he originally considered and it is in line with expected future contributions (Columbia St. No. 104-R, pp. 12-13).

Q. DO YOU AGREE WITH MR. GORE'S CONCLUSION?

A. No. I do not. I agree that his claim amount more closely matches future AON Hewitt projected payments into the pension fund.[1] However, the 2015 through 2018 projections will likely change as time progresses. The further out into the future those projections are, the more likely they will be modified going forward.

Q. DID THE COMPANY PROVIDE AN UPDATE TO ITS PENSION EXPENSE CLAIM?

A. Yes. Mr. Gore updated the Company's pension claim to reflect the modified capitalization percentage of 33.84% (Columbia St. No. 104-R, p. 4). This change resulted in total pension expense of $5,553,167, or pension expense of $3,673,984 ($5,553,167 x 66.16%) and capitalized pension expense of $1,879,183 ($5,553,167 x 33.84%) (Columbia Ex. JTG-R2, Sch. 1, p. 10).

Q. DO YOU AGREE WITH THE COMPANY'S MODIFIED CAPITALIZATION PERCENTAGE OF 33.84%?

A. Yes. The Company has updated its data to include data up through December 2012 in its 5-year average. This produces a more accurate and up-to-date result.

[1] I&E Ex. No. 2-SR, Sch. 1, p. 3, line 22.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR PENSION EXPENSE?

A. Yes. I have two changes to my recommendation. First, I recommend a total allowance amount equal to the 2014 AON Hewitt projection of $3,249,000.[2] This amount is more forward-looking than my original recommendation; however, it is not so far forward-looking that it becomes speculative in nature. The second change to my recommendation results in my acceptance of the Company's updated expense and capitalization percentages of 66.16% and 33.84%, resulting in a pension expense allowance of $2,149,538 ($3,249,000 x 66.16%) and a capitalized pension allowance of $1,099,462 ($3,249,000 x 33.84%).

PROFIT SHARING AND STOCK REWARDS

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING PROFIT SHARING AND STOCK REWARDS.

A. In direct testimony, I recommended that the Company's entire claim for direct employees' profit sharing expense ($231,934), capitalized direct employees' profit sharing ($111,825), direct employees' stock rewards expense ($139,296), direct employees' capitalized stock rewards ($67,160), NCSC-allocated profit sharing and stock rewards expense ($1,018,707), and NCSC-allocated capitalized profit sharing ($27,942), or a total of $1,596,864, be denied (I&E St. No. 2, p. 20).

[2] I&E Exhibit No. 2-SR, Schedule 1, p. 3, column 7, line 22.

The profit sharing benefit is based on NiSource meeting its earning per share goal (I&E Ex. No. 2, Sch. 10, p. 2). These payouts appear to be made independent of quality of service, efficiency, or safety goals of Columbia, and the stock rewards are only available to top-level employees (I&E Ex. No. 2, Sch. 8, p. 2). Ratepayers should not be obligated to pay for an expense that is based only on earnings goals and is unrelated to the provision of safe and reliable service (I&E St. No. 2, p. 20).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia Witness Hoelzer responded to my recommendation for profit sharing and stock rewards (Columbia St. No. 120-R). Witness Hoelzer disagreed with my recommendation indicating that the profit sharing plan supports employees' retirement savings, and that plans such as this are becoming a traditional element of retirement savings. Furthermore, he indicated the lack of defined benefit plans for new hires and opines that, "As an element of a balanced competitive benefit program, profit sharing contributions into the Retirement Savings Plan should be allowed." (Columbia St. No. 120-R, p. 9.)

Q. DO YOU AGREE WITH MR. HOELZER'S POSITION CONCERNING THE COMPANY'S PROFIT SHARING PLAN?

A. No. I never stated that the Company could not or should not offer profit sharing benefits to employees. My recommendation merely pointed out that the profit sharing benefit is based solely on NiSource meeting its earnings per share goal (I&E Ex. No. 2, Sch. 10, p. 2). These payments appear to be made independent of quality of service, efficiency, or safety goals of Columbia (I&E St. No. 2, p. 20).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION FOR STOCK REWARDS?

A. Yes. Company Witness Hoelzer expressed disagreement with my recommendation and opined that stock rewards should be allowed because they are a "common element of compensation at certain levels of organizations throughout the U.S." (Columbia St. No. 120-R, p. 9). He indicated that this benefit aids the Company in attracting and retaining talented executive-level employees and expressed his belief that it may be difficult to do so without stock rewards (Columbia St. No. 120-R, p. 10).

Q. DO YOU AGREE WITH WITNESS HOELZER?

A. No. I never said that the Company should discontinue its profit sharing or stock rewards programs. I simply acknowledged the reliance on earnings per share targets and the fact that only a select few Company employees are eligible to receive such benefits. I continue to recommend that ratepayers should not be obligated to fund benefits that are based on the reliance of earnings per share targets, and/or benefits that are only offered to the Company's top echelon of employees.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I do not.

<u>SYSTEM SERVICES – BUSINESS PROMOTION SERVICES</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING SYSTEM SERVICES – BUSINESS PROMOTION SERVICES.

A. In direct testimony, I recommended that the total claim of $2,079,833 be denied. This includes the expense portion of $1,608,646 and the capitalized portion of $471,187 (I&E St. No. 2, p. 23). Business promotion services consist of costs that promote the Company's corporate image or the use of natural gas, thereby promoting Columbia's business. These costs are not necessary to provide safe and reliable utility service to customers and for this reason should not be funded by ratepayers.

Q. EXPLAIN THE COMPANY'S RESPONSE TO YOUR RECOMMENDATION CONCERNING SYSTEM SERVICES – BUSINESS PROMOTION SERVICES.

A. Company Witness Shoemaker disagreed with my recommendation to disallow this expense for ratemaking purposes. Mr. Shoemaker states that "Business Promotion costs include the coordination of new, conversion and added load customers in the markets served by NiSource, including Columbia Gas of Pennsylvania," and that these costs "include the maintenance of service to the Company's largest customers, acting as a single source contact" for those large industrial and commercial customers (Columbia St. No. 112-R, p. 4). He indicated that analysis is performed concerning conversion from alternate fuels to natural gas, service requirements for new construction of homes and businesses, comparisons between alternate fuels and natural gas, education of customers on energy efficiency and conservation, and natural gas safety. He further indicated that the addition of new customers helps to spread the cost, and that ratepayers benefit from economies of scale achieved in this endeavor (Columbia St. No. 112-R, pp. 4-5).

Q. DO YOU AGREE WITH WITNESS SHOEMAKER?

A. No. I believe he has only helped to solidify my recommendation to disallow this expense because his explanations make it sound like the Company is merely promoting itself over other fuel providers. Furthermore, my understanding is that the Company already has expense categories for education of ratepayers concerning efficiency and natural gas safety, and any amount attributable to such cause here appears to be duplicative.

Q. DO YOU HAVE ANY CHANGES TO YOUR ORIGINAL RECOMMENDATION FOR SYSTEM SERVICES – BUSINESS PROMOTION SERVICES?

A. No.

INCENTIVE COMPENSATION – DIRECT EMPLOYEES

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING INCENTIVE COMPENSATION – DIRECT EMPLOYEES.

A. In direct testimony, I recommended a total allowance for incentive compensation of $1,023,953, which was further broken down by applying my recommended capitalized and O&M expense percentages (34.12% and 65.88% respectively) as was done in my pension expense recommendation. For incentive compensation expense I recommended $674,580 ($1,023,953 x 65.88%) or a reduction of $707,142 ($1,381,722 - $674,580). Additionally, for capitalized incentive compensation, I recommended $349,373 ($1,023,953 x 34.12%), or a reduction of $316,811 ($666,184 - $349,373) (I&E St. No. 2, p. 25).

My overall adjustment resulted from two changes: (1) a reduction to the portion of the benefit paid by ratepayers, sharing the cost equally between ratepayers and shareholders (I&E St. No. 2, p. 26); and (2) an adjustment to reflect the recommended change to the expensed and capitalized percentages.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company Witness Hoelzer referenced the Commission's recent PPL Electric Utilities decision[3] where the recovery of incentive compensation was permitted due to consistency with prior Commission decisions when such compensation

[3] *Pa. PUC v. PPL Electric Utilities Corp.*, R-2012-2290597 (Order entered Dec. 28, 2012).

programs are focused on improving operational effectiveness (Columbia St. No. 120-R, p. 3). Further, Mr. Hoelzer states that if only partial recovery is allowed it sends a message that variable pay is not valued as a tool to encourage Company efficiencies and customer services. He opines this would send a message that fixed base pay without incentives is preferable, and he cites reports from the Company's consultant in support of variable pay (Columbia St. No. 120-R, pp. 4-5). He then discusses how the Company's employees are accountable for quality of service, efficiency, and safety goals, and explains the requirements of the Company's incentive planning and individual goal setting process (Columbia St. No. 120-R, p. 6).

Q. DO YOU AGREE WITH MR. HOELZER'S RESPONSE?

A. No. I believe that Mr. Hoelzer misunderstood my recommendation. I never intended to present an argument against variable pay in and of itself. I merely recommended that the way it is structured (with a heavy reliance on earnings per share targets), I believe sharing the cost between ratepayers and shareholders is more equitable.

In my opinion, if ratepayers are to be responsible for the entire cost of incentive compensation, most emphasis should be placed on individual performance and providing safe and reliable service to ratepayers.

Q. DO YOU AGREE THAT, AS A PART OF THE INCENTIVE COMPENSATION PLAN, THE COMPANY HOLDS EMPLOYEES ACCOUNTABLE FOR QUALITY OF SERVICE, EFFICIENCY, OR SAFETY GOALS?

A. Yes. Based on what the Company has presented I agree with this. However, if the Company's earnings per share target is not met, no amount of incentive compensation is payable for net operating earnings per share ("NOEPS"), and the amount payable for Business Unit performance is reduced by 50% (I&E Ex. No. 2-SR, Sch. 2, pp. 1-2). This means that if the earnings per share target is not met, the incentive compensation payment is automatically reduced by 50%. Given this heavy reliance on corporate earnings, it is my opinion that the cost of this benefit should be shared equally between ratepayers and shareholders.

Q. DID ANYONE ELSE ADDRESS INCENTIVE COMPENSATION FOR DIRECT EMPLOYEES IN REBUTTAL TESITMONY?

A. Yes. Mr. Gore provided an update for incentive compensation to reflect the Company's adjusted expense and capitalization percentages, which result in an updated total Company claim of $2,047,906, which can be further broken down as $1,354,895 ($2,047,906 x 66.16%) for expense, and $693,011 ($2,047,906 x 33.84%) for the capitalized portion (Columbia St. No. 104-R, p. 3, and Columbia Ex. JTG-R2, Sch. 1, p. 8).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR INCENTIVE COMPENSATION – DIRECT EMPLOYEES?

A. Yes. Based on my acceptance of the Company's change to its expensed and capitalized percentages for wages and benefits I have an update to the dollar amounts of my recommendation. My updated recommendation for incentive compensation expense – direct employees is $677,447 [($2,047,906 x 50%) x 66.16%], and my updated recommendation for capitalized incentive compensation – direct employees is $346,506 [($2,047,906 x 50%) x 33.84%].

<u>**SYSTEM SERVICES – INCENTIVE COMPENSATION**</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING SYSTEM SERVICES – INCENTIVE COMPENSATION.

A. In direct testimony, I recommended an allowance of $934,952 for the expensed portion of system services – incentive compensation, or a reduction of $934,953 ($1,869,905 - $934,952), and a capitalized amount of $231,842, or a reduction of $231,842 ($463,684 - $231,842) (I&E St. No. 2, p. 28). This recommendation was made in order to share the cost equally between shareholders and ratepayers for the same reason discussed in my recommendation for direct employees' incentive compensation due to the heavy emphasis placed on earnings per share targets.

Q. DID THE COMPANY SUBMIT REBUTTAL TESTIMONY IN RESPONSE TO THIS RECOMMENDATION?

A. Yes. Columbia Witness Hoelzer disagreed with my recommendation for the same reasons presented above in the Incentive Compensation – Direct Employees section (Columbia St. No. 120-R, pp. 2-10).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I disagree with Mr. Hoelzer's argument presented in rebuttal testimony, and I continue to recommend a 50/50 split for ratepayers and shareholders to fund the cost of this benefit.

LABOR – ACTIVE EMPLOYEES AT MAY 2012

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING LABOR.

A. My recommendation in direct testimony for labor related to the Company's claim for 510 active employees as of May 2012. I recommended an allowance of \$25,677,651 (\$38,976,398 x 65.88%), or a reduction of \$619,725 (\$26,297,376 - \$25,677,651). Additionally, I recommended a capitalized labor allowance of \$13,298,747 (\$38,976,398 x 34.12%), or an increase of \$619,725 (\$13,298,747 - \$12,679,022) (I&E St. No. 2, pp. 29-30). This reflects my recommended change to the Company's labor allocation between expensed and capitalized amounts resulting from the use of more current data in the 5-year historic average (I&E St. No. 2, pp. 15-17).

Q. DID THE COMPANY SUBMIT REBUTTAL TESTIMONY CONCERNING YOUR RECOMMENDATION?

A. Yes. Company Witness Gore updated the Company's capitalization and O&M expense percentages to reflect a more current 5-year average based on the years 2008 through 2012. This change results in an expense percentage of 66.16% and a capitalization percentage of 33.84% (Columbia St. No. 104-R, p. 2).

Q. DID THE COMPANY MAKE ANY OTHER CHANGES TO ITS PAYROLL CLAIM?

A. Yes. Mr. Gore presented the following updates in his rebuttal testimony (Columbia St. No. 104-R, pp. 2-3): (1) a change to the O&M portion using the new percentage of 66.16%; (2) a change in the union contract increases for the fully projected future test year; (3) an update to the affiliate labor percentage using a detailed evaluation by employee type; and (4) a change to the 2013 and 2014 non-union wage increase date from March to June.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION MADE IN DIRECT TESTIMONY?

A. Yes. Based on this updated information, I am willing to accept the Company's changes made to its labor claim in rebuttal testimony.

<u>EMPLOYEE INSURANCE PLANS & THRIFT PLAN – ACTIVE EMPLOYEES AT MAY 2012</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING THE EMPLOYEE INSURANCE PLANS & THRIFT PLAN.

A. In direct testimony, I recommended an allowance of $4,677,480 ($7,100,000 x 65.88%), or a reduction of $112,891 ($4,790,371 - $4,677,480) to the Company's expense claim. Additionally, I recommended a capitalized amount of $2,422,520 ($7,100,000 x 34.12%), or an increase of $112,891 ($2,422,520 - $2,309,629) to the Company's claim. This recommendation was based upon the previously discussed adjustment to capitalized and expensed percentages (I&E St. No. 2, p. 32).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDED ADJUSTMENT TO THE EMPLOYEE INSURANCE PLANS & THRIFT PLAN?

A. Yes. The Company updated its claimed expense and capitalization percentages to reflect a 5-year average of 2008 through 2012, thereby addressing my concern.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. I am willing to accept the Company's expense and capitalization percentages of 66.16% and 33.84% (respectively) as presented in rebuttal testimony.

<u>**PAYROLL TAXES – DIRECT EMPLOYEES**</u>

Q. SUMMARIZE YOUR DIRECT TESTIMONY CONCERNING PAYROLL TAXES – DIRECT EMPLOYEES.

A. In direct testimony, I recommended payroll tax expense of $1,514,123, or a reduction of $103,798 ($1,617,921 - $1,514,123), and capitalized payroll taxes of $802,608, or an increase of $22,543 ($802,608 - $780,065) (I&E Ex. No. 2, Sch. 15). Due to my adjustments to labor and incentive compensation, it became necessary to make a corresponding adjustment to the Company's share of payroll taxes that are expensed and capitalized. In calculating these adjustments, I used the Company's Payroll Tax to Labor Percentage of 7.92% in my calculation (I&E St. No. 2, pp. 33-34).

Q. DID THE COMPANY SUBMIT REBUTTAL TESTIMONY CONCERNING YOUR RECOMMENDED REDUCTION TO PAYROLL TAXES FOR DIRECT EMPLOYEES?

A. No. Witness Gore provided an updated claim for the Company's payroll taxes based on the Company's changes to payroll, an adjustment made to the percentage of total taxable from 99.18% to 99.17%, and the change to the Company's expensed and capitalized portions (Columbia St. No. 104-R, p. 7). These changes result in a total claim for the Company's share of payroll taxes of $2,353,628 (Columbia Ex. JTG-R2, Sch. 2, p. 1), which can be further broken down as an expense amount of $1,557,160 ($2,353,628 x 66.16%), and a capitalized portion of $796,468 ($2,353,628 x 33.84%).

Q. DO YOU AGREE WITH MR. GORE'S UPDATED CLAIM AMOUNTS FOR PAYROLL TAXES - DIRECT EMPLOYEES?

A. No. However, in theory, I am not disputing the changes he made that relate to adjustments to payroll, the percentage of total taxable payroll, and the change to the Company's capitalized and expensed percentages.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. I have an update based on the change to my incentive compensation recommendation for direct employees and my acceptance of the Company's updated percentage of expensed and capitalized payroll.

Q. WHAT IS YOUR UPDATED RECOMMENDATION FOR PAYROLL TAXES – DIRECT EMPLOYEES?

A. I recommend a total payroll tax allowance for direct employees of $2,272,531 (I&E Ex. No. 2-SR, Sch. 3), which can be further broken down as $1,503,506 ($2,272,531 x 66.16%) for payroll tax expense – direct employees, or a reduction of $53,654 ($1,557,160 - $1,503,506); and $769,025 ($2,272,531 x 33.84%) for capitalized payroll taxes – direct employees, or a reduction of $27,443 ($796,468 – 769,025) to the Company's updated claim.

<u>**SYSTEM SERVICES - PAYROLL TAXES**</u>

Q. SUMMARIZE YOUR DIRECT TESTIMONY CONCERNING SYSTEM SERVICES – PAYROLL TAXES.

A. In direct testimony, I recommended an NCSC-allocated payroll tax expense of $838,381, or a reduction of $74,048 ($912,429 - $838,381), and an NCSC-allocated capitalized payroll tax amount of $207,895, or a reduction of $18,362 ($226,257 - $207,895) (I&E St. No. 2, p. 35). As a result of my adjustment to incentive compensation, it became necessary to make a corresponding adjustment to the Company's NCSC-allocated share of payroll taxes that are expensed and capitalized. In calculating these adjustments, I used the Company's Payroll Tax to Labor Percentage of 7.92% (I&E St. No. 2, pp. 34-36).

Q. DID THE COMPANY SUBMIT REBUTTAL TESTIMONY CONCERNING YOUR RECOMMENDED REDUCTION TO SYSTEM SERVICES – PAYROLL TAXES?

A. No. However, the Company did indicate disagreement with my recommended adjustment to System Services – Incentive Compensation, thereby indirectly indicating disagreement with the related payroll tax adjustment (Columbia St. No. 120-R, pp. 2-9).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION MADE IN DIRECT TESTIMONY?

A. No. I continue to recommend a corresponding adjustment to payroll taxes for my reduction to System Services - Incentive Compensation (I&E Ex. No. 2-SR, Sch. 3).

Q. PLEASE SUMMARIZE YOUR UPDATED ADJUSTMENTS?

A. A summary of my updated adjustments follows.

	Columbia Current Claim Amount	Updated I&E Recommended Adjustment	Updated I&E Recommended Allowance
O&M Adjustments:			
GTI Expense	$207,674	($57,674)	$150,000
NiFIT Expense	$1,010,000	($606,000)	$404,000
Pension expense	$3,673,984	($1,524,446)	$2,149,538
Profit Sharing/Stock Rewards:			
Direct Profit Sharing	$231,934	($231,934)	$0
Direct-Stock Rewards	$139,296	($139,296)	$0
NCSC-Allocated	$1,018,707	($1,018,707)	$0
System Services-Business Promotion Services	$1,608,646	($1,608,646)	$0
Incentive Comp.-Direct Employees	$1,354,895	($677,448)	$677,447
System Svcs.-Incentive Comp.	$1,869,905	($934,953)	$934,952
Payroll Taxes-Direct Employees	$1,557,160	($53,654)	$1,503,506
System Svcs.-Payroll Tax	$912,429	($74,048)	$838,381
Total O&M Adjustments		**($6,926,806)**	

Rate Base Adjustments:			
Capitalized pension	$1,879,183	($779,721)	$1,099,462
Employee Profit Sharing	$111,825	($111,825)	$0
Employee Stock Rewards	$67,160	($67,160)	$0
System Svcs.-Profit Sharing	$27,942	($27,942)	$0
System Services-Business Promotion Services	$471,187	($471,187)	$0
Incentive Comp.-Direct Employees	$693,011	($346,505)	$346,506
System Services-Incentive Compensation	$463,684	($231,842)	$231,842
Payroll Taxes-Direct Employees	$796,468	($27,443)	$769,025
System Svcs.-Payroll Tax	$226,257	($18,362)	$207,895
Total Rate Base Adjs.		**($2,081,987)**	

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 3
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Direct Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

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Concerning:

Test Year
Rate Base
Annual Depreciation Expense
Cost of Service
Scaleback
Customer Cost Analysis
Residential Rate Design
Tariff Language
Forfeited Discounts

2-13-13
Hbg SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket Nos. R-2012-2321748**
	:	**M-2012-2323645**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION OF THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Jeremy B. Hubert, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as I&E Statement No. 3, I&E Exhibit No. 3, I&E Statement No. 3-SR, and I&E Exhibit No. 3-SR were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Jeremy B. Hubert
Jeremy B. Hubert
Fixed Utility Valuation Engineer
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: February 13, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremy Hubert. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. An outline of my education and employment experience is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers and the Company.

Q. WHAT ISSUES DO YOU ADDRESS IN YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company") requested $77,311,077 base rate revenue increase and specifically addresses the following issues:

- Fully Projected Future Test Year ("FPFTY");
- Use of the FPFTY as it applies to Rate Base and Annual Depreciation Expense;
- The effect of projected use per customer on present rate revenues;
- Use of the most representative cost of service study;
- Manner of scale back if less than the full revenue amount is granted;
- Customer Cost Analysis;
- Residential Rate Design;
- Tariff Changes;
- Forfeited Discounts.

TEST YEAR

Q. WHAT IS A TEST YEAR AND HOW IS IT USED BY A COMPANY IN A RATE PROCEEDING?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. Previously, in rate case proceedings, in order to meet its burden of proof, a utility could only use a historic test year ("HTY") or a future test year ("FTY"). A historic test year is a twelve-month period selected by a company that represents a recent full year of actual data. A future test year begins the day after the historic test year ends and is used in order to allow for the time it takes to adjudicate a rate proceeding by permitting a company to select a future time period upon which to base its financial information. This is necessary so that the rates set by the Commission reflect current and synchronized financial information. By using a future test year, a utility makes a projected annualized and normalized estimate of future revenues and expenses and a corresponding measure of value at the end of the future test year.

Q. HAVE RECENTLY ADOPTED STATUTORY AMENDMENTS MODIFIED A UTILITY'S ABILITY TO PROPOSE A FUTURE TEST YEAR THAT BEGINS AFTER THE RATE CASE IS COMPLETED?

A. Yes. On February 14, 2012, Act 11 of 2012 was signed into law, which amends Chapters 3, 13 and 33 of the Public Utility Code (Title 66 of the Pennsylvania Consolidated Statues). In particular, Chapter 3 of the Code was amended to provide that utilities may use a fully projected future test year to attempt to meet their burden of proof in rate cases. The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the application of the full suspension period permitted under Section 1308(d). See 66 Pa.C.S. §1308(d).

Q. AT THIS TIME, HAS THE COMMISSION ADOPTED RULES AND REGULATIONS REGARDING THE USE OF THE FULLY PROJECTED FUTURE TEST YEAR?

A. No. On August 2, 2012, the Commission entered its Final Implementation Order at Docket No. M-2012-2293611 addressing Act 11 ("*Implementation Order*"). In the *Implementation Order*, the Commission initiated a separate proceeding at Docket No. L-2012-2317273 for the purposes of adopting rules and regulations regarding the use of the FPFTY in accordance with 66 Pa.C.S. §315 (relating to burden of proof).

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. The Company used the twelve-month period ending May 31, 2012 as the historic test year, the twelve-month period ending May 31, 2013 as the future test year, as well as a fully projected future test year, the twelve-month period ending June 30, 2014.

Q. WHAT TEST YEAR HAS THE COMPANY USED TO CALCULATE ITS REQUESTED REVENUE REQUIREMENT IN THIS PROCEEDING?

A. Although the Commission has not yet developed the procedures and requirements for the use of a fully projected future test year, the Company selected a FPFTY ending June 30, 2014. As shown on page 7 of the *Implementation Order*, the Commission has shown interest in seeing full documentation to support the methods and assumptions used to develop the FPFTY.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE SELECTED TEST YEAR AND THE CLAIMED REVENUE DEFICIENCY IN THIS PROCEEDING?

A. The claimed revenue deficiency in this proceeding of $77,311,000 is higher than in previous cases because this rate case includes the revenue requirement associated with the capital invested prior to the new proposed rates' effective date as well as the capital invested during the fully projected future test year. In prior rate cases only the capital invested prior to the new rate effective date has been included (Columbia St. No. 1, p. 8).

Q. WHAT IS THE ADDITIONAL LEVEL OF REVENUE DEFICIENCY ASSOCIATED SOLELY WITH THE INCLUSION OF THE FULLY PROJECTED FUTURE TEST YEAR ENDING JUNE 30, 2014?

A. The additional level of revenue deficiency associated solely with the inclusion of the fully projected future test year is $21,942,430. Prior to the authorization of the FPFTY under Act 11, the Company presumably would have filed a revenue requirement of $55,368,623 in this proceeding. The difference between this revenue requirement and the as filed revenue requirement of $77,311,000 reflects the $21,942,430 impact of the fully projected future test year (I&E Ex. No. 3, Sch. 2).

RATE BASE

Q. WHAT IS MEASURE OF VALUE, ALSO REFERRED TO AS RATE BASE?

A. The measure of value, or rate base, is the depreciated original cost of a utility's investment in plant a utility has in place to serve customers plus other additions and deductions that the Commission determines to be necessary in order to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS THE DEPRECIATED ORIGINAL COST PLANT IN SERVICE AT THE END OF THE TEST YEAR DETERMINED?

A. The depreciated original cost is determined by subtracting the book reserve, which is the accumulation of all prior annual depreciation expense, and other items such as salvage value from the original cost of the plant in service that is used and useful in the public service. Prior to the passage of Act 11, that calculation would have been performed at a specific point in time that would have been at the end of the future test year. Under the FPFTY in Act 11, the depreciated original cost of the plant in service is now determined by taking a "snapshot" look at the depreciated original cost value of used and useful utility plant in service at the end of the fully projected future test year.

Q. WHAT OTHER ADDITIONS AND DEDUCTIONS TO THE DEPRECIATED ORIGINAL COST OF UTILITY PLANT ARE ALLOWED?

A. Some of the additions to the depreciated original cost of a company's investment in utility include materials and supplies, gas in storage, prepayments, and cash working capital. Some of the deductions include deferred income taxes and customer deposits. Some additions are applicable to a specific utility or utility type. The depreciated original cost claimed by Columbia is $1,137,739,347, shown on Columbia Exhibit No. 108, page 3. The claimed additions to the Company's depreciated original cost are as follows:

1. Materials and Supplies;
2. Gas Storage Underground;
3. Prepayments;

The deductions to the depreciated original cost are:

1. Deferred Income Taxes;
2. Customer Deposits;
3. Customer Advances.

Q. HOW IS THE MEASURE OF VALUE USED WITHIN THE RATEMAKING FORMULA?

A. The measure of value is one part of the financial equation used by the Commission, along with allowable expenses and rate of return, to determine the level of income a utility is granted an opportunity to earn and the revenue level needed to achieve that return. The equation used to determine the proper revenue requirement level is:

Revenue Requirement = (Measure of Value x Rate of Return) + Allowable Expenses.

Each item in the revenue requirement equation is synchronized to the test year period. If the date of any of the items in this equation is changed, all the other necessary data that a utility must file in a rate proceeding including the test year income statement, actual and projected customer levels and usage, cost of service study to determine expense responsibility among the various customer classes, and other financial information used to determine the utility's rate of return, must also be changed.

Q. WHAT IS THE TOTAL MEASURE OF VALUE CLAIMED BY THE COMPANY FOR THE FUTURE TEST YEAR ENDING MAY 31, 2013?

A. The Company's claimed measure of value for the future test year ending May 31, 2013, is $865,754,465 (Columbia Ex. No. 108, p. 3 of 11).

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE DOES THE COMPANY CLAIM WILL BE ASSOCIATED SOLELY WITH THE INCLUSION OF THE FULLY PROJECTED TEST YEAR ENDING JUNE 30, 2014?

A. The Company's claimed measure of value for the FPFTY ending June 30, 2014, is $1,011,680,660 (Columbia Ex. No. 108, p. 3 of 11). Therefore, the Company claims that $145,926,196 ($1,011,680,660 – $865,754,465) of rate base is associated solely with the inclusion of the FPFTY.

Q. DOES COLUMBIA'S $1,011,680,660 RATE BASE CLAIM FOR THE FPFTY ENDING JUNE 30, 2014, INCLUDE NET FORECASTED PLANT IN SERVICE?

A. Yes. Columbia Exhibit No. 108, Schedule 1, page 1 shows that the Company's plant in service at May 31, 2012, is $1,166,619,912. Pages 1-13 of Columbia Exhibit No. 108, Schedule 1 provide the Company's projected capital expenditures, plant additions, and retirements by month from June 2012 through June 2014, which support the Company's net forecasted plant in service of $1,477,108,215 at June 30, 2014, included in the Company's $1,011,680,660 rate base claim for the FPFTY ending June 30, 2014 (Columbia Ex. No. 108, p. 3, col. 5).

Q. HOW MUCH NET PLANT IS THE COMPANY PREDICTING IT WILL ADD IN THE FUTURE TEST YEAR ENDING MAY 31, 2013, AND THE FOLLOWING THIRTEEN MONTHS ENDING JUNE 30, 2014?

A. The Company is predicting it will add $142,476,950 of net plant during the future test year ending May 31, 2013, and $170,648,370 of net plant during the following thirteen months ending June 30, 2014 (Columbia Ex. No. 108, p. 3, ln. 2, cols. 2 & 4).

Q. WHAT ROLE DOES THE CONCEPT OF "USED AND USEFUL" PLAY IN THE TEST YEAR CONTEXT?

A. Historically, a fundamental principle of utility regulation was that a public utility should be permitted to include projects in rate base and earn a reasonable return on its investments after they became "used and useful" for the utility's public service. Since the Company has chosen to use a fully projected future test year provided for in Act 11, the traditional interpretation of the "used and useful" requirement for rate base inclusion of investments is unclear.

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING PLANT ADDITIONS THAT ARE PROJECTED TO BE IN SERVICE DURING THE FULLY PROJECTED FUTURE TEST YEAR AND THUS INCLUDED IN RATE BASE FOR RATEMAKING PURPOSES?

A. In the proceeding at Docket No. L-2012-2317273, it is expected that the Commission will address the appropriate standard to be established for "used and useful" facilities that are projected to be in service during the FPFTY to be included in the rate base for ratemaking purposes. In addition to addressing that standard, I also recommend that the Company provide the Commission's Bureaus of Technical Utility Services and Investigation and Enforcement with an update to

Columbia Exhibit No. 108, Schedule 1 no later than October 1, 2013, which should include actual capital expenditures, plant additions, and retirements by month from June 2012 through June 30, 2013. An additional update should be provided for actuals through June 30, 2014, no later than October 1, 2014.

Q. WHY DO YOU RECOMMEND THE COMPANY PROVIDE THESE UPDATES?

A. The concept of a fully projected future test year has never before been utilized by any Pennsylvania utility in a base rate proceeding. Through use of the FPFTY, a utility is allowed to require ratepayers in essence to pre-pay a return on a utility's projected investment in future facilities that are not only not in place and providing service at the time the new rates take effect, but also that are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be some timely verification of the projections. Therefore, requiring Columbia to provide updates demonstrating that actual investment comports with projections used in setting rates using the FPFTY, allows the Commission to measure and verify the accuracy of the Company's projected investments in future facilities on a timely basis.

ANNUAL DEPRECIATION EXPENSE

Q. WHAT IS ANNUAL DEPRECIATION EXPENSE?

A. Annual depreciation expense is an operating expense. It represents the loss of service value of plant in service that is incurred in connection with consumption and use of such plant and that is neither restored by current maintenance nor covered by off-setting insurance payments.

Q. HOW HAS COLUMBIA DEVELOPED ITS CLAIM FOR ANNUAL DEPRECIATION EXPENSE AND SALVAGE EXPENSE FOR THE FUTURE TEST YEAR ENDING MAY 31, 2013?

A. The Company has prepared schedules in an effort to support its total depreciation expense of $37,579,794. This amount includes $32,908,612 related to plant in service as of May 31, 2013 (Columbia Ex. No. 109, Sch. 1, Attachment A, pp. 51-53) and $4,671,182 of net salvage (Columbia Ex. No. 109, Sch. 1, Attachment A, p. 58).

Q. HAS COLUMBIA PREPARED SCHEDULES TO SUPPORT ITS CLAIM FOR ANNUAL DEPRECIATION EXPENSE AND SALVAGE EXPENSE FOR THE FULLY PROJECTED FUTURE TEST YEAR ENDING JUNE 30, 2014?

A. Yes. Columbia's total depreciation expense claim for the FPFTY is $41,961,336. This amount includes $37,097,005 related to plant in service as of June 30, 2014, (Columbia Ex. No. 109, Sch. 1, Attachment B, pp. 7-9) and $4,864,331 of net salvage (Columbia Ex. No. 109, Sch. 1, Attachment B, p. 14).

Q. HOW MUCH ADDITIONAL DEPRECIATION EXPENSE IS RECOVERED BY ALLOWING A FPFTY?

A. $4,381,542 ($41,961,336 - $37,579,794) of additional depreciation expense is recovered through use of a FPFTY.

<u>**PRESENT RATE REVENUE**</u>

Q. WHAT IS COLUMBIA'S CLAIM FOR PRESENT RATE REVENUES FOR THE FULLY PROJECTED FUTURE TEST YEAR ENDING JUNE 30, 2014?

A. The Company is claiming that it will receive $379,306,896 in present rate revenue (Columbia Ex. No. 103, p. 11, col. 3, ln. 15).

Q. IS THIS $379,306,896 BASED ON A PROJECTED NUMBER OF CUSTOMERS AND PROJECTED SALES VOLUMES?

A. Yes. The Company projected the number of customers and projected normalized usage by class to arrive at the $379,306,896 in total present rate revenue. The proper number of customers and sales volumes is critical in the determination of present and proposed revenue.

Q. WHAT TWO ISSUES CONCERNING PRESENT RATE REVENUE DO YOU WISH TO ADDRESS?

A. First, I will address an error in the projected number of bills for the Residential Sales Service ("RSS") class. Second, I will address the projected decline in average Residential customer usage.

Q. DID THE COMPANY RESPOND TO A DATA REQUEST THAT CORRECTED THE PROJECTED REDUCTION OF 17,976 RSS BILLS ATTRIBUTABLE TO CUSTOMER ATTRITION?

A. Yes. The Company's response to I&E-RS-41-D indicates that for the twelve months ending June 30, 2014, the Company projected the incorrect number of RSS customer bills in the filing by double counting implied attrition bills (I&E Ex. No. 3, Sch. 3). Correcting the number of projected RSS bills for the FPFTY increases the RSS customer charge revenue to $66,941,863, which is $168,345 more than the $66,773,518 shown on Columbia Exhibit No. 103, Schedule 1, page 21 ($66,941,863 - $66,773,518 = $168,345) (I&E Ex. No. 3, Sch. 4, p. 1, col. F, ln. 4).

Q. WHAT IS THE IMPACT TO PRESENT RATE REVENUE OF THIS CORRECTION?

A. This correction increases present rate revenue by $168,345.

Q. AFTER THIS CORRECTION, DO YOU AGREE WITH THE COMPANY'S CORRECTED PRESENT RATE REVENUE?

A. No. According to the Company, Residential customer usage projections should include a reduction to account for limited end uses for natural gas, accelerated appliance replacements, high efficiency appliance installations, modifications to new and existing buildings which are designed to decrease energy consumption, changes in consumer usage behavior in response to energy price changes and other economic influences (Columbia St. No. 2, pp. 13-14).

Q. WHAT AVERAGE USE PER RESIDENTIAL CUSTOMER IS THE COMPANY PROJECTING?

A. Based on the Company's proof of revenue schedules (Columbia Ex. No. 103, Sch. 1, pp. 21-30) and the Company's projected number of customers determined from the projected number of bills (Columbia Ex. No. 103, Sch. 2, pp 13-18), I determined the Company is projecting that the average usage per RSS customer will be 78.51 Dth per year (I&E Ex. No. 3, Sch. 4, p. 1, col. B, ln. 3). The Company is also projecting that the average usage per Residential Distributed Generation Sales Service ("RDGSS") customer will be 110.47 Dth per year (I&E Ex. No. 3, Sch. 4, p. 1, col. B, ln. 18), the average usage per Residential CAP customer will be 140.58 Dth per year (I&E Ex. No. 3, Sch. 4, p. 1, col. B, ln. 33), the average usage per Residential Distribution Service ("RDS") customer will be 105.38 Dth per year (I&E Ex. No. 3, Sch. 4, p. 2, col. B, ln. 3), and the average usage per Residential Distributed Generation Distribution Service ("RDGDS") customer will be 150.24 Dth per year (I&E Ex. No. 3, Sch. 4, p. 2, col. B, ln. 17). Therefore, I conclude that the Company is projecting an average composite use per Residential customer of 86.27 Dth per year (I&E Ex. No. 3, Sch. 4, p. 2, col. B, ln. 29).

Q. WHAT DATA DOES THE COMPANY USE AS PART OF ITS PROJECTION OF USAGE DECLINE FOR RESIDENTIAL CUSTOMERS?

A. The Company analyzed usage for the past twenty years (Columbia St. No. 2, p. 12).

Q. DO YOU AGREE WITH THE COMPANY'S PROJECTED AVERAGE COMPOSITE RESIDENTIAL USAGE?

A. No. I believe the Company has understated its projected residential usage.

Q. WHAT LEVEL OF RESIDENTIAL USAGE DO YOU RECOMMEND?

A. I believe that the average composite use per Residential customer will be 89.50 Dth per year for the FPFTY ending June 30, 2014 (I&E Ex. No. 3, Sch. 4, p. 2, col. H, ln. 29). With respect to efforts to calculate projected usage by residential customers today, I believe a 20-year time period is too long. Customer reductions in usage attributable to efficiency and conservation is more apparent in recent years as a result of conservation initiatives. When compared to usage twenty years ago, which predated customer initiatives, it tends to exaggerate the impact of decreased consumption by placing undue emphasis on older data that is not truly reflective of current consumption patterns. This, in turn, dilutes the most recent actual changes in usage, causing the Company to overstate the level of decline in consumption likely to be experienced going forward and understate projected usage. Based on recent history, it is not likely that consumption will continue to decrease at the level projected by the Company.

Q. HOW DID YOU DETERMINE THE 89.50 DTH PER YEAR PER RESIDENTIAL CUSTOMER?

A. Using the data contained in the Company's response to I&E-RS-6-D (I&E Ex. No. 3, Sch. 7), I calculated the average decrease in usage for Residential customers over the most recent six-year period (2006-2011) to be 0.20 Dth per year (I&E Ex. No. 3, Sch. 5, col. C, ln. 13). Based on the actual weather normalized usage per customer for 2011 of 90 Dth, I project that the average Residential customer will use 89.50 Dth for the FPFTY ending June 30, 2014 (I&E Ex. No. 3, Sch. 5, col. B, ln. 16).

Q. DOES THE MORE RECENT DATA INDICATE THAT USAGE HAS REMAINED FAIRLY LEVEL?

A. Yes. Between 2006 and 2011 average usage per Residential customer has stayed at approximately 91 Dth per year. The data also shows that weather normalized Residential usage actually increased in 2007 and 2010.

Q. DOES THE COMPANY'S PROJECTION OF AVERAGE USE PER RESIDENTIAL CUSTOMER FOR THE FUTURE TEST YEAR ENDING MAY 31, 2013 SUPPORT THE OVERALL TREND AND DECLINE IN USAGE?

A. No. The Company contradicts its contention that usage is declining by projecting a 14.2% increase in average use per Residential customer for the future test year ending May 31, 2013. The Company is projecting average usage per Residential customer to increase from 76.06 Dth for the historic test year ending May 31, 2012 to 86.89 Dth for the year ending May 31, 2013 (Columbia Ex. No. 10, Sch. 2, Attachment 1, pp. 6-7).

Q. WHAT USAGE SHOULD BE ADJUSTED SO THAT THE TOTAL USAGE PER RESIDENTIAL CUSTOMER EQUALS THE 89.50 DTH PER YEAR DESCRIBED ABOVE?

A. I recommend that the average use per Residential RSS customer be increased to 82.68 Dth per year so that the average composite usage for all Residential customers is 89.50 Dth per year (I&E Ex. No. 3, Sch. 4, p. 1, col. H, ln. 3).

Q. HOW MUCH SHOULD THE COMPANY'S PROJECTED RESIDENTIAL RSS SALES VOLUME BE INCREASED SO THAT THE AVERAGE USE PER RESIDENTIAL RSS CUSTOMER IS 82.68 DTH PER YEAR?

A. As shown on I&E Exhibit No. 3, Schedule 4, page 1, line 3, if Residential RSS customer usage is increased by approximately 1,226,360 Dth (24,336,386 Dth – 23,110,026 Dth), the average use per customer increases by 4.17 Dth per year to 82.68 Dth per year.

Q. WHAT IS THE TOTAL ADJUSTMENT TO RESIDENTIAL PRESENT RATE REVENUES YOU ARE RECOMMENDING AS A RESULT OF YOUR ANALYSIS?

A. My recommended average use per RSS customer and the Company's corrected number of RSS bills increases the present revenues for the Residential class by $8,739,061, as shown on I&E Exhibit No. 3, Schedule 6, column C, line 21.

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDED $8,739,061 INCREASE IN PRESENT REVENUES, SHOULD THERE ALSO BE A CORRESPONDING INCREASE IN THE COST OF GAS EXPENSE?

A. Yes. If the Commission accepts my recommendation, the Company must purchase additional gas than what is reflected in the filing.

Q. WHAT IS THE CORRESPONDING INCREASE IN THE COST OF GAS EXPENSE?

A. If the Commission accepts this present revenue adjustment, there should be a corresponding increase of $5,299,348 in the cost of gas expense for the additional gas, as shown on I&E Exhibit No. 3, Schedule 6, column C, line 22.

COST OF SERVICE

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study is a formalized analysis of costs that attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of such a study can be utilized to determine the relative cost of service for each class and help determine the individual class revenue requirements and, to the extent a particular class is above or below the system average rate of return, show the additional revenues each class receives or conversely the additional revenues that each class contributes to the Company's overall revenues. In addition to the relative provision of revenues, a relative rate of return is also provided which shows how the rate of return for each class compares to the system average rate of return.

Q. DID THE COMPANY PROVIDE A COST OF SERVICE STUDY IN ITS FILING?

A. Yes. The Company provided three cost of service studies in Columbia Exhibit No. 111. Schedule 1 of Columbia Exhibit No. 111 provides the results of a study using the Customer-Demand allocation method. The second cost of service study is provided in Schedule 2 of Columbia Exhibit No. 111 and utilizes the Peak and Average demand allocation method. The third cost of service study is provided in Schedule 3 of Columbia Exhibit No. 111 and is an average of the Customer-Demand study and the Peak and Average study.

The cost of service studies presented by Columbia are sponsored by Mr. John E. Skirtich. Columbia's studies each use a basic three step process of cost analysis: (1) functionalization; (2) classification of functionalized costs into demand, commodity, and customer cost categories; and (3) class allocation of functionalized, classified costs among the rate classes.

Q. HOW DO THE CUSTOMER-DEMAND AND PEAK AND AVERAGE COST OF SERVICE STUDIES PREPARED BY COLUMBIA DIFFER?

A. The two cost of service studies prepared by Columbia differ in that they are based on two alternative methods of allocating mains to the various classes of service. The Customer-Demand method classifies Distribution Mains as partially customer related and partially demand related. The customer portion of Mains is then allocated to classes based on number of customers, while the Demand portion of

Mains is allocated to classes based on contributions to peak (design) day demand. This methodology has been rejected in other natural gas base rate cases. The second cost of service study sponsored by Mr. Skirtich utilizes the Peak and Average methodology. This methodology allocates distribution mains to classes based partially on annual consumption (average demand) and partially on contributions to peak day demand.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE IMPACT OF THE TWO COST OF SERVICE METHODOLOGIES?

A. Yes. The LGS – Large General Sales Service rate group's relative return at present rates based on allocating mains on the Customer-Demand Study is 2.03, which implies that the cost of providing service is less than the revenue received from that class (Columbia Ex. No. 111, Sch. 1, p. 2). Conversely, according to the study utilizing the Peak & Average method, the relative return at present rates is 0.84 which implies that the cost of providing service is more than the revenue received from this rate group (Columbia Ex. No. 111, Sch. 2, p. 2).

Q. WHICH COST OF SERVICE STUDY DID THE COMPANY EMPLOY TO ALLOCATE THE PROPOSED REVENUE INCREASE?

A. Company witness Skirtich testifies that he used the Average study, which has an equal weighting of the Customer-Demand and Peak & Average studies, as a guide when designing the proposed revenue requirement and rates (Columbia St. No. 9, pp. 3-4).

Q. WHICH COST OF SERVICE STUDY DO YOU RECOMMEND THAT THE COMMISSION USE AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. I recommend that the Commission rely on the cost of service study that is based on allocating mains based on the Peak & Average method.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED USE OF THE PEAK & AVERAGE METHOD?

A. Yes. The Commission has previously reflected its recognition that Distribution Mains are built on the basis of year-round demands as well as peak demands. In the National Fuel Gas Distribution Company ("NFGD") 1994 base rate proceeding, the Commission accepted the Peak & Average methodology, stating "[t]he Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact." (*Pa. P.U.C. v. National Fuel Gas Distribution Co.*, 83 Pa. PUC 262 (1994).

Q. HOW DID THE COMPANY CLASSIFY AND ALLOCATE THE MAINS AND MAINS RELATED ACCOUNTS FOR THE PEAK & AVERAGE STUDY?

A. The Peak & Average study sponsored by Company Witness Skirtich reflects a 50 percent allocation of distribution mains investment based on design peak demand and 50 percent on the basis of annual demands.

Q. IN YOUR OPINION, IS THIS THE PROPER WAY TO CLASSIFY AND ALLOCATE THE FIXED COST OF MAINS AND MAINS RELATED ACCOUNTS?

A. Yes. The Commission previously determined in a 1994 Opinion and Order in the Pennsylvania American Water Company case at Docket No. R-00932670, Order entered July 26, 1994, at pages 111- 115, that direct customer costs include "the depreciation, return and income taxes associated with meter and service investment, the operation and maintenance expense for meters and services, and the expense associated with meter reading and billing." Mains are not included in any of these categories, and therefore should not be considered or classified as a customer cost. The basis for this determination is that the quantity and investment in mains does not change significantly if one customer joins or leaves the system. Mains are built to deliver gas, and the cost of mains cannot be assigned to one specific customer. Therefore, no portion of the fixed costs or depreciation expense associated with mains should be allocated to the customer cost function.

In a more recent Opinion and Order, the Commission reaffirmed that the cost of mains should be allocated on a combination of throughput and demand,

and therefore not allocated to the customer function (PPL Gas Utilities, Docket No. R-00061398, order entered February 8, 2007).

Q. DESCRIBE HOW COLUMBIA IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.

A. Considering that rate classes Large Distribution Service ("LDS") and Main Line Distribution Service ("MDS") both exhibited a relative rate of return above 1.0 at present rates in Columbia's preferred cost of service study which utilizes the Average of the Customer-Demand and Peak & Average studies, the present level of revenues was maintained for both classes. The relatively small increase in revenue for the LDS and MDS classes shown below is due to the resetting of the State Tax Adjustment Surcharge ("STAS") adjustment back to 0%. The remaining classes received increases in proportion to their cost-based revenue requirements at proposed revenue levels, as computed in Columbia's cost of service studies.

Q. WHAT PERCENT INCREASE IS COLUMBIA PROPOSING FOR THE VARIOUS CUSTOMER CLASSES AS PRESENTED IN THE COST OF SERVICE STUDIES?

A. The Company's proposed revenue distribution is presented in the following table (Columbia Ex. No. 111, Sch. 2, p. 6).

Company Proposed Revenue Distribution				
Class	**Present Rates**	**Proposed Rates**	**Increase**	**Percent**
RS/RDS	$274,373,270	$336,152,969	$61,779,699	22.5%
SGS/SGDS	$75,451,790	$89,807,740	$14,355,950	19.0%
LGS	$5,588,480	$6,170,570	$582,090	10.4%
SDS	$9,530,454	$10,112,142	$581,688	6.10%
LDS	$12,860,564	$12,871,575	$11,011	0.09%
MDS	$1,502,338	$1,503,496	$1,158	0.08%
Total	**$379,306,896**	**$456,618,492**	**$77,311,596**	**20.4%**

Q. WHAT IS ONE RATE STRUCTURE CONSIDERATION WHEN ESTABLISHING PROPOSED RATES?

A. One of the considerations in establishing proposed rates is the rate of return by customer class and the corresponding relative rate of return by class. The optimum goal should be to establish proposed rates so that the revenue received from a particular class is equal to the corresponding costs of providing service to that class. A relative rate of return above 1.00 for a class indicates that the cost of providing service is less than the revenue received from that class. A relative rate of return below 1.00 for a class indicates that the cost of providing service is more than the revenue received from that class. The relative rate of return for each class, as shown by the Company's Peak & Average study is shown on Columbia Exhibit No. 111, Schedule 2, page 1, line 14.

Q. DID COLUMBIA MOVE THE VARIOUS CUSTOMER CLASSES CLOSER TO THE SYSTEM AVERAGE RATE OF RETURN BASED ON THE RESULTS OF THE COST OF SERVICE STUDIES?

A. Yes. All classes moved towards the system average rate of return (Columbia St. No. 9, Ex. JES-1).

SCALEBACK

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE OF APPROXIMATELY $77,311,000?

A. If the Commission grants Columbia less than the full increase it has requested, I recommend that the first $200,000 be used to reduce the proposed revenue received from the Small Distribution Service ("SDS") customers (I&E Ex. No. 3, Sch. 8, p. 2, col. G, ln. 16). The next $6,000,000 reduction should be used to reduce the proposed revenue received from the RS/RDS customers (I&E Ex. No. 3, Sch. 8. p. 3, col. D, ln. 16).

Q. WHY DO YOU RECOMMEND THE FIRST $200,000 BE USED TO REDUCE THE REVENUE RECEIVED FROM THE SDS CUSTOMERS?

A. Under present rates the relative rate of return for the SDS class is 3.15 (Columbia Ex. No. 111, Sch. 2, p. 2, col. G, ln. 14). Under proposed rates the relative rate of return decreases to 1.66 (I&E Ex. No. 3, Sch. 8, p. 1, col. G, ln. 14). My recommendation to apply the first $200,000 reduction to the SDS class will lower the relative rate of return further to 1.58 so that it is closer to 1.00 than the Company proposed (I&E Ex. No. 3, Sch 8, p. 2, col. G, ln. 14). Therefore, this class should receive the first dollar relief of $200,000. Under proposed rates, the RS/RDS class receives the highest percentage increase producing a relative rate of return in excess of 1.00. Even though the Company only proposed a 6.1% increase for the SDS class, the rate of return for the SDS class will still be well above the system average under proposed rates as shown by the results of the Peak & Average study (I&E Ex. No. 3, Sch. 8, p. 1, col. G).

Q. HOW DID YOU DETERMINE THAT THE ADDITIONAL REDUCTIONS UP TO $6,000,000 SHOULD BE USED TO REDUCE THE REVENUE RECEIVED FROM THE RS/RDS CUSTOMERS?

A. Under proposed rates, the residential class receives the highest percentage increase producing a relative rate of 1.05 (I&E Ex No. 3, Sch. 8, p. 1, col. D, ln. 14). Applying the next $6,000,000 dollars lowers the relative rate of return for the residential class to 1.03, which is closer to unity, resulting in an increase of approximately 20% for the residential class. This 20% is approximately equal to the 19% increase the Company proposed for next largest class, the SGS/SGDS class. As shown on I&E Exhibit No. 3, Schedule 8, page 3, the result of my first and second dollar relief recommendations produces relative rates of return for each class, excluding the LDS and MDS classes, that indicate the revenue that will be received from these classes is moving toward the corresponding costs of providing service to each class.

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION REDUCES THE INCREASE BELOW $71,111,596?

A. If the Commission further reduces the allowed increase below $71,111,596 ($77,311,596 - $6,200,000), I recommend that the revenues for all classes, excluding the LDS and MDS classes, be reduced so that the increase for each class is proportional to the percentage increase shown on I&E Exhibit No. 3, Schedule 8, page 3, line 20. I recommend that the LDS and MDS rates not be scaled back, since the Company has proposed no increase in base rates for these classes.

CUSTOMER COST ANALYSIS

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is part of a cost of service study that includes only customer costs. It is used to determine the appropriate customer charges for the various classes.

Q. DID THE COMPANY PREPARE AN ANALYSIS TO SUPPORT INCREASING THE CUSTOMER CHARGES?

A. Yes. The Company completed two customer charge analyses presented in Columbia Exhibit No. 111, Schedule 1, pp. 14-18, though it refers to them as a "system charge." Pages 14 through 16 contain the Company's customer charge study based on the Customer-Demand COSS and includes the customer portion of mains costs. The other study included on pages 17 and 18 of Schedule 1 is similar, but excludes the customer component of mains and other operations. Columbia's analysis including the customer portion of mains costs results in a Residential customer charge of $33.46 per month (Columbia Ex. No. 111, Sch. 1, p. 14, col. E, ln. 41) while its analysis excluding the customer component of mains produces a system charge of $18.00 per month (Columbia Ex. No. 111, Sch. 1, p. 17, col. E, ln. 38).

Q. HAS THE COMMISSION PREVIOUSLY DETERMINED WHAT ITEMS SHOULD BE RECOVERED IN A CUSTOMER CHARGE?

A. Yes. In determining the appropriate items to be included in the customer charge, the Commission affirmed its long-standing principle that only direct customer costs should be recovered in a customer charge in Columbia's most recently concluded base rate case at Docket No. R-2010-2215623 (Order entered October 14, 2011). In that case, the Commission adopted the I&E recommendation to limit the determination of the customer charge to the following items: operating expenses associated with meters and house regulators, the maintenance expense associated with services, meters and house regulators, cost of meter reading, customer records and customer assistance costs, the return dollars and depreciation expense related to meters, regulators, and services. The Commission excluded all the other costs that Columbia Gas claimed should be recovered in the customer charge (Columbia Order, p. 51).

Q. **WHAT ITEMS DID THE COMPANY INCLUDE IN ITS "SYSTEM CHARGE" CALCULATIONS?**

A. As shown on Columbia Exhibit No. 111, Schedule 1, pages 17 and 18, the Company has included expenses related to distribution, customer accounts expenses, customer service and information expenses, sales expenses, the depreciation expense, net salvage amortized, and return dollars and income taxes on customer-based rate base. Customer service and information expenses are broken down into supervision expenses, customer assistance expenses, informational & instructional expenses, miscellaneous expenses, large customer relations, office supplies and expenses, and rents. Sales expenses are also broken down into demonstration expenses and advertising expenses. Uncollectible accounts expense, miscellaneous customer accounts expense, and office supplies and expenses can be found under the heading of customer accounts expenses (I&E Ex. No. 3, Sch. 9, p. 5).

Q. **SHOULD THE COMPANY HAVE INCLUDED ALL OF THESE ITEMS LISTED ABOVE TO DETERMINE THE COSTS THAT SHOULD BE RECOVERED IN THE CUSTOMER CHARGE?**

A. No. Any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs. These are costs that increase each time a new customer is added or decrease when a customer is lost.

Q. HAVE YOU CALCULATED WHAT THE MONTHLY CHARGES SHOULD BE FOR COLUMBIA?

A. Yes. A customer charge calculation reflecting only direct customer costs is presented on Schedule 9 of I&E Exhibit No. 3. Based on my customer cost analysis, which abides by the same principles I adhered to in Columbia's last base rate case and was adopted by the Commission, I determined that the Company incurs $16.53 per month in customer costs for each RS/RDS customer, $25.67 per month in customer costs for each SGS/SGDS customer, $180.00 per month in customer costs for each LGS customer, $97.49 per month in customer costs for each SDS customer, $211.93 per month in customer costs for each LDS customer, and $200.26 per month in customer costs for each MDS customer (I&E Ex. No. 3, Sch. 9, p. 1, ln. 11).

Q. WHAT ITEMS DID YOU INCLUDE IN YOUR CUSTOMER COST ANALYSIS TO DETERMINE THE APPROPRIATE CUSTOMER CHARGE?

A. I included the following direct customer costs: meter and regulator expenses, expenses for services and customer installations, meter and regulator maintenance expenses, expenses for meter reading and customer records & collection, customer assistance expense, depreciation expense and net salvage amortized for meters, services, regulators, meter installations, and industrial measure and regulating equipment, and the rate base related return and income taxes on customer-based rate base (I&E Ex. No. 3, Sch. 9).

<u>RESIDENTIAL RATE DESIGN</u>

Q. DESCRIBE COLUMBIA'S CURRENT AND PROPOSED RESIDENTIAL RATES.

A. Columbia's current Residential rates consist of an $18.73 per month customer charge and a single delivery rate of $2.6708 for each Dth of gas delivered in excess of 2.1 Dth in any given month. Under Columbia's recommended Residential rate design a customer would pay a monthly "system charge" of $19.00 and a single delivery rate of $3.8621 per Dth for all gas delivered (Columbia Ex. No. 103, Sch. 8). Customers will continue to pay on a volumetric basis through Riders PGC and USP for the amount of gas commodity used each month and for the recovery of Universal Service Program costs.

Q. WHAT DOES THE COMPANY PROVIDE AS SUPPORT FOR ITS PROPOSED $19.00 "SYSTEM CHARGE" FOR RESIDENTIAL CUSTOMERS?

A. On page 15 of Columbia Statement No. 15, Company Witness Strauss claims that the $19.00 system charge is justified because Residential customers are used to paying the current fixed charge of $18.73, so rounding the current fixed charge up to $19.00 will keep the fixed charge around a level that customers are familiar with paying and will still fall at the low end of the "system costs" developed by Company Witness Skirtich in Exhibit 111.

Q. WHAT IS THE IMPACT OF THE COMPANY'S FULL PROPOSED RATES ON A RESIDENTIAL CUSTOMER'S BILL?

A. Schedule No. 6 of Columbia Exhibit 111 shows typical bill comparisons for the full proposed increase. With the proposed increase, a typical Residential customer using an average of 7.3 Dth of gas per month would see a bill increase of $15.75 (23.4%), from $67.17 to $82.92 per month (I&E Ex. No. 3, Sch. 10, col. E, ln. 18). Due to the Company's proposal to eliminate the 2.1 Dth allowance in the fixed charge, the highest percentage increase of 30.5% would be experienced by Residential customers that use approximately 2.1 Dth of gas in a given month (I&E Ex. No. 3, Sch. 10, col. E, ln. 9).

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL RESIDENTIAL RATE DESIGN CHANGES?

A. Yes. In recognition of the statements contained in the Commission's Order in Columbia's prior rate case, which encourages parties to present alternate rate mechanisms for its consideration going forward, the Company has presented three rate design options. The Company's primary Residential rate design option, partially described above and shown on Columbia Exhibit No. 103, Schedule 8, includes a Revenue Normalization Adjustment ("RNA").

Q. WHAT IS A REVENUE NORMALIZATION ADJUSTMENT?

A. The RNA is a decoupling mechanism which adjusts customers' monthly bills in an attempt to insulate the Company's revenues from fluctuations in customer sales. The fluctuations in sales that the RNA addresses are typically caused by abnormal weather, but could also be the effect of economic variables and energy conservation measures.

Q. DESCRIBE COLUMBIA'S REVENUE NORMALIZATION ADJUSTMENT?

A. Columbia's proposed RNA is a per therm adjustment based on a Commission-approved level of revenues that will be applied to all Residential service rate schedules, excluding CAP customers. The RNA is computed on a semi-annual basis and creates a credit to be added to or charge to be subtracted from the monthly distribution charge for Residential customers. The RNA adjusts for the level of revenues actually received during each six-month period and is designed to stabilize the Company's revenues.

A benchmark base revenue per Residential customer will be determined for two separate six-month periods, October 1st through March 31st and April 1st through September 30th, and will be recalculated with each rate case filing. If actual base revenue per customer exceeds the benchmark amount for one of the six-month periods, then the Company will calculate a credit to be applied to Residential customers' bills beginning in the next corresponding six-month period. Conversely, if the actual base revenue per customer is below the benchmark amount, then the Company will collect such deficiency through the RNA during the next corresponding six-month period.

Q. HAS COLUMBIA PROVIDED ANY OTHER RESIDENTIAL RATE DESIGN OPTIONS IN ADDITION TO ITS PRIMARY RATE DESIGN PROPOSAL WHICH INCORPORATES THE RNA?

A. Yes. Columbia has provided two additional rate design options. Columbia's second Residential rate design option consists of a customer charge of $29.00, a distribution rate of $2.4579 per Dth for all consumption, and a Weather Normalization Adjustment ("WNA"). Columbia's third Residential rate design option consists of a Levelized Distribution Charge ("LDC"), which is a flat monthly fee of $45.49 for the delivery services provided by Columbia. Customers would pay on a volumetric basis through Riders PGC and USP for the amount of gas commodity used each month and for the recovery of Universal Service Program costs.

Q. WHAT IS THE COMPANY'S JUSTIFICATION FOR PROPOSING A RESIDENTIAL CUSTOMER CHARGE OF $29.00 PER MONTH WITH THE COMPANY'S SECOND RATE OPTION?

A. Company Witness Strauss claims that the $29.00 "system charge" under the second rate option is justifiably higher than the $19.00 "system charge" under the Company's primary rate design because this option includes a Weather Normalization Adjustment that only protects the Company and the customers from variations due to weather, as opposed to the Company's primary rate design, which includes a Revenue Normalization Adjustment that protects against variations in energy usage due to other factors as well, such as the economy and end-use energy efficiency (Columbia St. No. 15, p. 25).

Q. DESCRIBE COLUMBIA'S WEATHER NORMALIZATION ADJUSTMENT PROPOSED UNDER THE COMPANY'S SECOND RATE OPTION.

A. Columbia's WNA is a temperature-based weather normalization mechanism that permits the Company to calculate the non-gas portion of customers' bills based upon normal weather and will be applied to all Residential customers' bills for the period of October through May.

Q. DESCRIBE COLUMBIA'S THIRD RESIDENTIAL RATE DESIGN OPTION, WHICH INCLUDES A LEVELIZED DISTRIBUTION CHARGE OF $45.49 PER MONTH.

A. This third rate design option proposed by Columbia, a levelized distribution charge ("LDC"), is essentially a Straight Fixed Variable ("SFV") rate design. Under SFV pricing, the flat monthly charge covers all the fixed costs associated with serving customers, and any consumption is billed at the actual cost of the commodity. This removes, or decouples, the Company's recovery of revenues based on throughput because revenue lost through reduced throughput is offset by the reduced incremental cost associated with recovery based on throughput, and instead is recovered through a high fixed monthly charge.

Q. ARE SFV AND REVENUE DECOUPLING RELATED?

A. They are related to some degree. Revenue decoupling usually preserves the traditional rate design utilized by most regulatory commissions around the United States. Distribution service rates are typically composed of a fixed customer charge and a volumetric distribution charge. As described above, revenue decoupling establishes a level of allowed revenue per customer to be recovered under these rates. If actual recovery falls below the target, then rates are increased in a subsequent period to make up for the short fall and vice versa. With the Company's SFV pricing under the LDC, the $45.49 rate is not going to be "truedup" in any given year and is directly charged to customers on a fixed per-customer basis.

Q. WHY DOES COLUMBIA PROPOSE TO RECOVER RESIDENTIAL REVENUE ENTIRELY FROM CUSTOMER CHARGES WITH LITTLE OR NO CONTRIBUTION FROM USAGE CHARGES?

A. Company Witness Kempic claims that the Company is experiencing a drop in use per customer while continuing to invest large amounts of capital in its distribution system (Columbia St. No. 1, p. 13).

Q. WHAT ARE THE BENEFITS OF A LEVELIZED DISTRIBUTION CHARGE AS CLAIMED BY MR. KEMPIC?

A. According to Mr. Kempic, the LDC will provide the Company with a more stable and predictable revenue stream. Additionally, Mr. Kempic claims that moving the collection of distribution related costs to a fixed charge basis will prevent customers from overpaying or underpaying each month, address intra-class cross subsidization, improve bill stability, and achieve bill simplicity (Columbia St. No. 1, pp. 22-25). Furthermore, Mr. Kempic claims that a lack of opportunities for more certain revenue recovery can discourage investors (Columbia St. No. 1, p. 20).

Q. WHAT COMMENTS DO YOU HAVE CONCERNING THE COMPANY'S PROPOSAL TO MOVE TOWARDS REVENUE RECOVERY PRIMARILY FROM CUSTOMER CHARGES?

A. I do not believe that this type of rate structure represents sound regulatory policy, best serves the public interest, or is necessary in Pennsylvania.

Significantly higher monthly fixed charges typically present public acceptability problems. Customers resist paying a high monthly charge month after month regardless of use, especially if it does not reflect changes in their use of the product. In other words, if customers try to reduce their gas consumption as a means of reducing their expense, they will expect, reasonably so, to see that reflected on their bill. With the Company's proposal, which includes a much higher customer charge, that will not happen to the full extent that it could. In addition, low usage customers within a customer class would experience a greater percentage increase than high usage customers (I&E Ex. No. 3, Sch. 10, col. K). This seems almost punitive to customers who attempt to control their usage. Although this rate structure allows a greater guarantee of revenues for a utility, it may also reduce the benefit for consumers to conserve and use less gas.

Q. WHAT HAS MR. KEMPIC PROVIDED IN SUPPORT OF HIS CLAIM THAT COLUMBIA'S LACK OF OPPORTUNITIES FOR MORE CERTAIN REVENUE RECOVERY CAN DISCOURAGE INVESTORS?

A. Mr. Kempic cites to a 2009 investor presentation before this Commission by Mr. Richard Cortright of Standard and Poor's Rating Service as support for its contention that the investment community looks for a rate structure that provides more certainty.

Q. DOES MR. CORTRIGHT'S PRESENTATION TO THE COMMISSION ACCURATELY REFLECT COLUMBIA'S NEED FOR A REVENUE DECOUPLING MECHANISM AT THIS TIME?

A. No. As the "various trackers" noted on the presentation provided by Mr. Cortright (included in (I&E Ex. No. 3, Sch. 11)) demonstrate, Pennsylvania already has approved several of the revenue decoupling mechanisms generically identified by Mr. Cortright in 2009, but which appear not to be recognized by either Mr. Cortright then or Columbia now in pursuing its alternative rate design proposals. Most importantly these "various trackers" also include but are not limited to the FPFTY and Distribution System Improvement Charge ("DSIC"), the "forward-looking measures," "pre-approval of significant capital outlays," and "infrastructure surcharges" referenced by Mr. Cortright, which were provided for in Act 11 after this investor presentation was made. I also note that the American Gas Association map provided on page 19 of Mr. Kempic's testimony, despite purporting to be accurate as of March 2012, also fails to acknowledge these two very important developments in Pennsylvania, which I also note occurred after the Commission's decision in Columbia's last base rate case in which the Commission recommended the parties consider alternative rate designs in Columbia's next case.

Finally, a flat fixed monthly customer charge represents guaranteed revenue to Columbia and therefore reduces the risk of the Company's operations. If the Commission ultimately grants Columbia a form of revenue decoupling through any one of the means proposed in this case, this should be reflected through a lower return on equity than requested by the Company as addressed by I&E witness Emily Sears.

Q. PLEASE ADDRESS MR. KEMPIC'S CLAIM THAT CUSTOMER ACCEPTABILITY OF A HIGHER CUSTOMER CHARGE IS NOT SUPPORTED BY THE LEVEL AND TYPE OF CUSTOMER COMPLAINTS THE COMPANY RECEIVED FOLLOWING THE INCREASE TO ITS CUSTOMER CHARGE IN ITS LAST BASE RATE CASE (COLUMBIA ST. NO. 1, P. 14).

A. The current monthly Residential charge of $18.73 includes an allowance of 2.1 Dth. Additionally the overall monthly bills are lower than they were in 2008 when gas costs were much higher, which likely limited customer complaints.

Q. PLEASE ADDRESS MR. KEMPIC'S CLAIM THAT COLLECTING THE MAJORITY OF REVENUE THROUGH FIXED CHARGES WILL PREVENT INTRA-CLASS SUBSIDIZATION.

A. Rather than preventing the type of intra-class subsidy that Mr. Kempic describes, I believe that the Company's efforts to recover more revenues through fixed charges presents a greater opportunity for such a situation to occur. For example, under the current rate structure a residential customer in a small house that only uses gas for cooking and water heating pays $18.73 per month plus usage exceeding 2.1 Dth. Under the LDC rate design, this same customer would be charged $45.49 per month, and would pay the same monthly charge as a customer who lives in a very large house and uses gas for heating, cooking and water heating. Recovering the same costs from these two residential customers increases intra-class subsidies. In other words, in this example, the customer with lower usage is subsidizing the customer with greater usage as a result of them both paying the same high monthly rate for the privilege of being a customer.

Q. PLEASE ADDRESS MR. KEMPIC'S CLAIM THAT CUSTOMERS REQUIRE BILL SIMPLICITY.

A. The Company believes that moving to a rate structure in which virtually all of the utility's costs are recovered through a flat monthly fee will simplify the bill and will enhance the customers' ability to understand the value of competition ("Choice"). The Company also claims that the customer charge, usage charge and 1307(f) charge is confusing to customers because the usage charge bears no relationship to how the Company incurs costs (Columbia St. No. 1, p. 24).

Q. WHAT IS YOUR RESPONSE TO THESE CLAIMS?

A. Rates should not be set on how a utility believes customers may or may not err in calculating savings. Moreover, while bills should be simple to understand, a bill with a high fixed customer charge is no simpler than a bill with a usage-based distribution charge. In fact, given a customer's propensity to review his monthly utility cost for gas service in terms of how much gas he used in that month, the best way to enhance the customer's ability to understand his bill and the value of Choice is to have no customer charge at all. With no customer charge, a customer will see proportional savings tied directly to his reduction in usage.

For example, if a customer's bill is $100, and the customer reduces usage by 10%, the bill will decrease to $90. Unfortunately, with a high monthly customer charge and little or no usage charge, the customer's bill will decrease by less than 10% or possibly not at all.

Finally, it is not clear why the Company is primarily concerned with customer's perceived savings from choosing a natural gas supplier on one hand, but on the other hand steadfastly defends a distribution rate structure that penalizes customers who are able to lower usage.

Q. PLEASE ADDRESS MR. KEMPIC'S CLAIM THAT COLUMBIA'S BILL AS CURRENTLY STRUCTURED WITH A FIXED MONTHLY CUSTOMER CHARGE, A USAGE-BASED DISTRIBUTION CHARGE, AND A GAS COMMODITY CHARGE CONFUSES CUSTOMERS

BECAUSE A USAGE CHARGE BEARS NO RELATIONSHIP TO HOW A COMPANY INCURS COSTS TO PROVIDE DISTRIBUTION SERVICE (COLUMBIA ST. NO. 1, PP. 23-27).

A. My review of the complaints provided by Mr. Kempic to support his assertion reveals that customers care about how much they pay, and not about how the Company incurs or recovers costs to provide distribution service. Mr. Kempic even acknowledges that customers do not care how a utility recovers its costs, they just want to understand their bills and be treated fairly. As some of the complaints reveal, customers do not understand why, particularly with their conservation efforts, Columbia's rates keep rising. I do not oppose efforts to simplify bills, but I believe that it is just as simple to break the bill into a distribution-usage charge and a gas commodity charge as it is to have a high fixed monthly charge, a commodity charge, and no usage charge. Further, it is unfair to not allow customers to realize benefits of conservation through a reduction to usage charges.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED COLUMBIA'S EFFORTS TO ESTABLISH A LEVELIZED DISTRIBUTION CHARGE?

A. Yes. The Commission rejected the Company's proposed LDC in Columbia's last base rate case. The Company apparently recognizes the Commission's prior findings regarding the proposed LDC as noted on page 21 of Columbia Statement No. 1:

> While Columbia believes the Levelized Distribution Charge is a superior rate design because of its simplicity and its direct relation to the manner in which Columbia incurs its costs to provide distribution service, Columbia recognizes that the parties and the Commission disagree.

Q. WHAT IS YOUR RECOMMENDATION IN REGARDS TO THE RESIDENTIAL RATE STRUCTURE?

A. I recommend removing the 2.1 Dth per month allowance currently included in the fixed monthly charge. This will reduce the fixed monthly charge to a level that includes only those costs that are properly recovered through a customer charge. Based on my customer cost analysis, shown on I&E Exhibit No. 3, Schedule 9, I recommend a Residential customer charge of $16.53 per month. Additionally, while I do not agree with the Company's assertions that additional rate design modifications are necessary, particularly in light of the provisions afforded in Act 11 subsequent to Columbia's last base rate case, if the Commission is inclined to adopt a revised rate design, I recommend that the Company's proposed Revenue Normalization Adjustment be accepted as proposed.

Q. WHY DO YOU MAKE SUCH A RECOMMENDATION?

A. My recommended Residential rate design maintains usage based charges that reflect individual consumption patterns, while providing the Company with more revenue stability to the extent greater stability is desired by the Commission. The monthly bill comparison on Schedule 10 of I&E Exhibit No. 3 shows that that my recommended Residential rate design creates a more uniform increase throughout the range of usage and does not produce a large decrease in the monthly bills of larger use customers and large increase in the bills of smaller use customers as the Company's LDC would produce. Nor does my recommended rate design produce a large increase of 55% for small use customers and a minimal increase for large use customers as the Company's second rate design option (the WNA) produces.

Also, as described above, the decline in residential usage has showed signs of leveling off. Thus, even if after the enactment of Act 11 the Commission determines greater revenue stability is required through the RNA, allowing an adjustment to reflect potential declines in usage will have the least impact on customers while still affording the Company revenue stability. In addition, any increase in the average usage per customer, such as occurred in 2007 and 2010, will reduce customers' usage rates, preventing the Company from receiving a windfall and benefitting the customer.

Q. WHY DOES YOUR RECOMMENDED RATE DESIGN PRODUCE A SLIGHT DECREASE IN MONTHLY BILLS FOR LOW USAGE CUSTOMERS?

A. The Company's current Residential rate design consists of a minimum charge of $18.73 which includes a usage allowance of 2.1 Dth per month and a volumetric distribution charge of $2.6708 for each Dth of gas delivered over 2.1 Dth per month. This minimum charge of $18.73 is calculated by multiplying a volumetric charge of $2.6708 by 2.1 (2.1 Dth) and then adding the customer charge of $13.12 to that amount. Therefore, since the Company proposed to remove the 2.1 Dth allowance contained in the fixed monthly charge of the present rates, it appears as though I am recommending a decrease in the customer charge. Actually, I am recommending an increase of $3.41 to the customer charge, from $13.12 per month to $16.53 per month.

Q. HAVE ANY ORGANIZATIONS PROMOTED LOW CUSTOMER CHARGES IN CONJUNCTION WITH REVENUE DECOUPLING?

A. Yes. The Regulatory Assistance Project ("RAP") is a non-profit organization that provides research and analysis to public officials on natural gas and electric utility regulation. In a presentation on the subject of revenue decoupling RAP noted the following criteria for "Elements of Fair and Effective Decoupling":

- Significant commitment to energy efficiency;
- Progressive rate design that keeps fixed rate elements low (or zero);
- A "collar" on rates – no more than X% change in a year. Additional amounts deferred;
- Scheduled periodic rate cases: 3-5 years;
- Capital Structure Adjustment if weather risk is shifted to consumers.[1]

Therefore, if acknowledging the use of revenue decoupling, the Commission should remain mindful of maintaining low monthly charges and continuing to recognize the benefits of energy efficiency.

[1] Cheryl Harrington and Jim Lazar, Regulatory Barriers to Energy Efficiency; Eliminating Disincentives, Creating Right Incentives, presented to the Minnesota PUC, May 24, 2006.

DECOUPLING

Q. ARE THERE ANY OTHER NATURAL GAS UTILITIES IN PENNSYLVANIA THAT HAVE INSTITUTED A REVENUE DECOUPLING MECHANISM?

A. Yes. Philadelphia Gas Works ("PGW") is the only natural gas utility in Pennsylvania that currently has a revenue decoupling mechanism. PGW is regulated under the cash flow method as a means of determining the necessary amount of revenue needed to operate safely and reliably.

Q. WHY WAS PGW GRANTED PERMISSION TO IMPLEMENT A DECOUPLING MECHANISM?

A. All rates for other gas utilities other than PGW are determined by traditional rate base / rate of return regulation where cash flow is not directly considered. The rates PWG customers pay are determined by the company's cash flow, not its rate base or return dollars. This unique circumstance requires different ratemaking considerations and dictates the different ways PGW is regulated. A weather normalization adjustment was requested by PGW and permitted to become effective to help PGW stabilize its income and cash flow and make it easier for PGW to maintain its budget and corresponding cash flow year to year.

Q. PLEASE DESCRIBE THE COMPANY'S CLAIMS CONCERNING MODERN DAY RATE DESIGNS IN OTHER STATES?

A. The Company describes various rate structures approved in other states including a straight fixed variable charge in Ohio, a revenue per customer rate structure in Massachusetts, and a revenue normalization adjustment in Virginia (Columbia St. No. 1, pp. 15-21).

Q. PLEASE ADDRESS THE COMPANY'S CLAIMS CONCERNING MODERN DAY RATE DESIGNS IN OTHER STATES?

A. There may be several factors at play in other states of which this Commission has not been fully informed. Therefore, it would be unwise and premature simply to accept as persuasive Columbia's claim that other states have adopted some or another form of revenue decoupling without also closely and comprehensively reviewing all other factors involved in each state's decision.

For example, in Ohio, the straight fixed variable charge is only \$17.81 per month, or \$27.68 less than the \$45.49 straight fixed variable charge determined by the Company in this case. The Public Utilities Commission of Ohio ("PUCO") also decreased the allowed rate of return to reflect the reduced risk and funded programs for low-income customers. Similarly, I am advised by counsel that in other jurisdictions in which Columbia affiliates operate, the regulatory commissions have imposed other conditions as a result of implementation of novel rate designs. For example, in Virginia a revenue normalization adjustment decoupling mechanism was allowed by statute, but also required help for low-income/low-usage customers. And in Maryland and Massachusetts there were also reductions to equity returns. Therefore, in order to make a valid comparison, the Commission should consider these and all other aspects of ratemaking, not just the solitary concept of a revised rate design approved by other states as suggested by the Company. However, such a thorough analysis is not possible within the time constraints of a base rate case.

Further, despite what other states have or have not approved, this Commission rightfully remains concerned that customers continue to be able to derive benefits from their conservation efforts, benefits that are greatly reduced by the Company's proposed rate designs.

<u>TARIFF LANGUAGE – SYSTEM CHARGE</u>

Q. IS THE COMPANY PROPOSING TO CHANGE THE DEFINITION OF CUSTOMER CHARGE IN THE PROPOSED TARIFF?

A. Yes. The Company is proposing to change all references to "customer charge" in the existing tariff to a "system charge" (Supplement No. 109 to Tariff Gas - P.U.C. No. 9, pp. 16-20, 77, 90, 92, 108, 112, 118).

Q. WHY IS THE COMPANY PROPOSING TO CHANGE THE DEFINITION OF THE CUSTOMER CHARGE TO SYSTEM CHARGE IN THE PROPOSED TARIFF?

A. The Company believes the term "system charge" more accurately reflects what the fixed charge represents because the monthly charge should recover the monthly customer costs as well as costs to maintain the entire system (Columbia St. No. 16, pp. 5-6).

Q. SHOULD THE COMPANY BE PERMITTED TO REDEFINE THE MONTHLY CHARGE?

A. No. As described above, the concept of a customer charge and its manner of calculation enjoys long-standing precedent before this Commission as a reasonable part of the rate structure policy and the overall ratemaking process. This policy should not change simply because of the way Columbia desires to recover its costs. Further, the Company uses the term to enhance its argument to convert the monthly and usage charge rate structure to a rate structure that only includes a monthly charge, a change I strongly believe harms low usage customers and discourages conservation. Therefore, until the Commission abandons the concept and manner of developing a customer charge, the term should not be changed in the Company's tariff.

FORFEITED DISCOUNTS

Q. WHAT ARE FORFEITED DISCOUNTS?

A. Columbia assesses a separate charge for any customers who do not pay their bill on time. The term forfeited discounts revenue refers to the revenue received by the Company as a result of this charge.

Q. HOW ARE REVENUES FROM FORFEITED DISCOUNTS DETERMINED?

A. According to the Company's current tariff, if a customer fails to pay the full amount of any bill, a delayed payment penalty charge of one and one-quarter percent (1.25%) per month will accrue on the customer's bill that is unpaid on the due date.

Q. WHAT LEVEL OF FORFEITED DISCOUNTS IS THE COMPANY CLAIMING AT PRESENT RATES FOR THE FULLY PROJECTED FUTURE TEST YEAR ENDING JUNE 30, 2014?

A. As shown on page 11 of Company Exhibit No. 103, the Company is claiming $944,367 in forfeited discounts revenue for the fully projected future test year ending June 30, 2014. This amount represents 0.2499% ($944,367/$377,898,106) of total sales and transportation revenue.

Q. WHAT LEVEL OF FORFEITED DISCOUNTS IS THE COMPANY CLAIMING AT PROPOSED RATES FOR THE FULLY PROJECTED FUTURE TEST YEAR ENDING JUNE 30, 2014?

A. The Company is claiming that its level of forfeited discounts at proposed rates will be $944,367 for the fully projected future test year ending June 30, 2014 (Columbia Ex. No. 103, p. 11). This is the same amount as claimed under present rates, and it represents 0.2075% ($944,367/$455,209,183) of total sales and transportation revenue for that period.

Q. HAS THE COMPANY MADE ANY ADJUSTMENTS TO THIS CLAIM?

A. Yes. In response to I&E-RS-25-D the Company admitted that it mistakenly omitted the adjustment to Account 487 - Forfeited Discount revenue resulting from the requested revenue requirement increase. The Company's updated level of forfeited discounts at proposed rates is $1,137,568 for the fully projected future test year ending June 30, 2014 (I&E Ex. No. 3, Sch. 1).

Q. HOW DID THE COMPANY DETERMINE THE $1,137,568 AMOUNT?

A. The $1,137,568 represents 0.2499% of total sales and transportation revenue of $455,209,183. This percentage was determined by averaging the actual percentage of forfeited discount revenues to total billed revenue for three historic periods; the year ended May 31, 2010, May 31, 2011, and May 31, 2012.

Q. WHY SHOULD REVENUE FROM FORFEITED DISCOUNTS BE 0.2499% OF TOTAL SALES AND TRANSPORTATION REVENUE?

A. It is reasonable to expect that forfeited discounts revenues will increase whenever a utility's base rates are increased as a result of a base rate proceeding. Since forfeited discounts are currently 1.25% of a customer's bill, increasing gas service revenue through a rate increase will cause revenues from forfeited discounts to increase over time.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE AMOUNT OF REVENUE RECEIVED FROM FORFEITED DISCOUNTS AT THE COMMISSION APPROVED REVENUE LEVEL?

A. I recommend that the Company include revenue from forfeited discounts equal to 0.2499% of total sales and transportation revenue upon determination of the total revenue that the Company is ultimately granted the opportunity to recover through rates by the Commission.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JEREMY B. HUBERT

PROFESSIONAL EXPERIENCE AND EDUCATION

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Mechanical Engineering, 2003

- Attended EUCI Introduction to Rate Design for Electric Utilities, Philadelphia, PA
- Attended EUCI Introduction to Cost of Service Concepts and Techniques for Electric Utilities, Philadelphia, PA
- Attended NARUC Rate School, San Diego, CA

EXPERIENCE:

11/2006 - Present

Office of Trial Staff, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

10/2005 – 11/2006

Pennsylvania Department of Transportation - Harrisburg, Pennsylvania

Materials Technician – Responsible, primarily, for performing a variety of technical duties associated with the routine testing of coarse aggregates according to AASHTO and PTMs.

05/2005 – 10/2005

Gatter & Diehl, Inc. Consulting Engineers - Harrisburg, Pennsylvania

Mechanical Designer – Responsible, primarily, for assisting engineers and CADD technicians in the design aspects of HVAC, plumbing, and fire protection systems.

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

- Village Water Company, Docket No. R-00072351
- United Water of Pennsylvania, Inc., Docket No. A-210013F0017
- Total Environmental Solutions, Inc.
  Treasure Lake Division, Docket No. R-00072493
- National Fuel Gas Distribution Corporation, 1307(f) proceeding,
  Docket No. R-2008-2012502
- PECO Energy Company, Docket No. R-2008-2028394
- PPL Gas Utility Corporation, 1307(f) proceeding,
  Docket No. R-2008-2039634
- Newtown Artesian Water Company, Docket No. R-2008-2042293
- Equitable Gas Company, Docket No. R-2008-2029325
- National Fuel Gas Distribution Corporation, 1307(f) proceeding,
  Docket No. R-2009-2083181
- Columbia Gas of Pennsylvania, 1307(f) proceeding,
  Docket No. R-2009-2093219
- UGI Central Penn Gas, Inc., 1307(f) proceeding,
  Docket No. R-2009-2105909
- Pennsylvania American Water Company, Docket No. R-2009-2097323
- PPL Electric, Energy Efficiency and Conservation Plan,
  Docket No. M-2009-2093216
- Utilities, Inc. of Pennsylvania, Docket No. R-2009-2117402
- Aqua Pennsylvania, Inc., Docket No. R-2009-2132019
- Newtown Artesian Water Company, Docket No. R-2009-2117550
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2009-2149262
- National Fuel Gas Distribution Corporation, 1307(f) proceeding,
  Docket No. R-2010-2150861
- T.W. Phillips Gas and Oil Company, Docket No. R-2010-2167797
- Columbia Gas of Pennsylvania, 1307(f) proceeding,
  Docket No. R-2010-2161920
- UGI Central Penn Gas, Inc., 1307(f) proceeding,
  Docket No. R-2010-2172922
- Total Environmental Solutions, Inc.
  Treasure Lake Water Division, Docket No. R-2010-2171918
- Total Environmental Solutions, Inc.
  Treasure Lake Sewer Division, Docket No. R-2010-2171924
- Wellsboro Electric Company, Docket No. R-2010-2172662
- Columbia Gas of Pennsylvania, Inc., Docket Nos. R-2010-2215623

- Columbia Gas of Pennsylvania, 1307(f) Proceeding
  Docket No. R-2011-2228696
- The Newtown Artesian Water Company, Docket Nos. R-2010-2215623
  R-2010-2201974
- United Water Pennsylvania, Inc. Docket No. R-2011-22332985
- Aqua Pennsylvania, Inc., Docket No. R-2011-2267958
- PECO Energy Company – Gas Division, 1307(f) proceeding,
  Docket No. R-2012-2302784
- PPL Electric Utilities Corporation, Docket No. R-2012-2290597

I&E Exhibit No. 3
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

Columbia Gas of Pennsylvania

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

Exhibit to Accompany

the

Direct Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:

Test Year
Rate Base
Annual Depreciation Expense
Cost of Service
Scaleback
Customer Cost Analysis
Residential Rate Design
Tariff Language
Forfeited Discounts

2-13-13
Hbg

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RS

Question No. I&E-RS-25-D:

Reference Columbia Exhibit No. 103, page 11. Explain why the Forfeited Discount revenue of $944,367 at current rates remains the same at proposed rates.

Response:

Columbia mistakenly omitted the adjustment to Account 487, Forfeited Discount revenue resulting from the requested revenue requirement increase. Please refer to I&E-RS-25-D Attachment A for the calculation of the Increase to Forfeited Discount revenue resulting from the requested revenue requirement filed in this case.

Columbia Gas of Pennsylvania, Inc.
Calculation of Forfeited Discounts (Account 487) Based Upon the Request Revenue Requirement
For the Twelve Months Ending June 30, 2014

Line No.		12 Mos May 2010	12 Mos May 2011	12 Mos May 2012	Total 3 Year Average		
1	Per Books Acct 487	$ 1,040,582	$ 1,200,505	$ 929,702	$ 3,170,789		
2	Per Books Billed Revenue	$ 397,688,616	$ 521,827,918	$ 349,170,640	$ 1,268,687,174		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2617%	0.2301%	0.2663%	0.2499%		
4	Fully Forecasted Rate Year Sales Revenue based upon Proposed Rates (Ex. 103, Sch. 7, Page 14, Line 21, Col. 4)					$	345,802,681
5	Fully Forecasted Rate Year Transportation Revenue (Ex. 103, Sch. 7, Page 20, Line 18, Col. 4)					$	109,406,502
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$	455,209,183
7	3 Year Average (Ex. MJB-2, Page 3, Line 7)						0.2499%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$	1,137,568
9	Fully Forecasted Rate Year Acct 487 (Ex. MJB-2, Page 3, Line 8)					$	944,367
10	Annualization Adjustment (Line 8 - Line 9)					$	193,201

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RS

Question No. I&E-RS-49-D:

Reference Columbia Statement No. 1, page 8, lines 3-13. Provide the additional level of revenue deficiency associated solely with the inclusion of the fully projected future test year ending June 30, 2014 compared to a future test year ending May 31, 2013. Include all assumptions used.

Response:

The additional level of revenue deficiency associated solely with the inclusion of the fully projected future test year ("FPFTY") is $21,942,430.

Please refer to I&E-RS-49-D Attachment A, which details the calculation.

There are three claim adjustments that are included in the FPFTY adjustments in the revenue requirement filed in this case that would have been included as part of the future test year (FTY) had this case been filed under the pre-Act 11 rules. The adjustments are:

- Tax Refund Amortization - change in the refund as described in Witness Fischer testimony (Statement No. 11).
- NIFit Amortization – proposed recovery of costs as described in Witness Gore testimony (Statement No. 4).
- DIMP – the DIMP expenses as described in Witness Kitchell testimony (Statement No. 7) would have been annualized in the FTY.

Under the pre-Act 11 filing rules, the Company would have filed a revenue requirement of $55,368,623 (Attachment, Line 15). The difference between this revenue requirement and the as filed revenue requirement of $77,311,053 reflects the $21,942,430 impact of the FPFTY.

Columbia Gas of Pennsylvania
Revenue Requirement with FTY ended May 31, 2013

Line #	Description (A)	Reference (B)	(C)	(D)	(E)	(F)
1	Future Test Year Rate Base	Exh. 102, Sch 3, Pg 3, Col 4, Ln 24	865,754,465			
2	Filed for Return on Rate Base	Exh. 102, Sch 3, Pg 3, Col 8, Ln 25	8.52%			
3	Operating Income Requirement	Line 1 x Line 2		73,762,280		
4	FTY Operating Income @ Present Rates	Exh. 102, Sch 3, Pg 3, Col 4, Ln 23		56,124,573		
5	Operating Income Deficiency before Adjustments	Line 3 - Line 4		17,637,707		
6	Revenue Conversion Factor	Exh. 102, Sch 3, Pg 5, Ln 19		1.73450081		
7	FTY Revenue Requirement Before Adjustments	Line 5 x Line 6			30,592,617	
8	Adjustments To FTY as filed:					
9	Tax Refund Amortization	Exh. 107, Pg 8, Col 4, Ln 19	10,825,020			
10	Revenue Conversion Factor	Exh. 102, Sch 3, Pg 5, Ln 19	1.73450081			
11	Tax Refund - Revenue Requirement Impact	Line 9 x Line 10		18,776,006		
12	NIFIt Amortization	Exh. 104, Sch 1, Pg 2, Col 5, Ln 30		1,010,000		
13	DIMP	Exh. 104, Sch 1, Pg 2, Col 5, Ln 20		4,990,000		
14	Revenue Requirement Impact of all FTY Adjustments	Line 11 + Line 12 + Line 13			24,776,006	
15	Future Test Year Revenue Deficiency with Adjustments	Line 7 + Line 14				55,368,623
16	Fully Projected Future Test Year Revenue Deficiency	Exh. 102, Sch 3, Pg 3, Col 7, Ln 2				77,311,053
17	Additional level of Revenue Deficiency associated with					
18	inclusion of Fully Projected Future Test Year	Line 16 - Line 15				21,942,430

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation and Enforcement – Set RS

Question No. I&E-RS-41-D:

Reference Columbia Exhibit No. 103, Schedule No. 2, page 13, column 4. Explain how the reduction of 17,976 bills attributable to customer attrition was determined for Rate RSS customers. Include all calculations.

Response:

Customer Count December 2012	380,104
Plus: New Customer Premises during 2012	3,253
Less: Customer Count December 2013	381,859
Implied Attrition Customers	(1,498)
Times 6 Billing Periods	6
Implied Attrition Bills	(8,988)

Due to a cell reference error in the Excel spreadsheet, Implied Attrition Bills were double counted.

Attrition is an annual concept and applied to December customer levels. By using year-end December customer counts and not test year-end May customer counts, Columbia eliminates any possibility of temporary seasonal attrition.

Columbia Gas of Pennsylvania, Inc.
BI&E Proposed Present Rate Revenues and Cost of Gas
Residential Customers
For the 12 Months Ended June 30, 2014

		Per Company						Per BI&E				
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Description	Billing Units Columbia Ex. No. 103 Schedule No 1	Total Normal Usage (Dth/cust.)	Total Consumption (Dth) Columbia Ex. No. 103 Schedule No. 1	Base Rate	Revenue ($)	Increase to Present rate Revenues ($)	Billing Units	Total Normal Usage (Dth/cust.)	Total Consumption (Dth)	Base Rate	Revenue ($)
1	Rate Schedule RSS - Residential Sales Service											
2	RESIDENTIAL											
3		294,349 customers	78.51	23,110,026.2				294,349 customers	82.68	24,336,386.4		
4	Customer Charge	3,565,057			18.73	66,773,518	$168,345	3,574,045			18 73	66,941,863
5	Commodity Charge:											
6	First 2.1 Dth			5,977,219.1	0.0000	0				5,977,219.1	0.0000	0
7	Over 2.1 Dth			17,132,807.1	2.6708	45,758,301	$3,275,363			18,359,167.3	2.6708	49,033,664
8	Rider USP - Universal Service Plan			23,110,026.2	0.3595	8,308,054				23,110,026.2	0.3595	8,308,054
9	Subtotal					120,839,873						124,283,581
10	STAS					(140,174)						(144,169)
11	Base Rate Revenue					120,699,699						124,139,412
12	Gas Cost			23,110,026.2	4.3212	99,863,045	$5,299,348			24,336,386 4	4.3212	105,162,393
13	Unbundled Uncollectibles			23,110,026.2	0.0590	1,363,492				23,110,026.2	0 0590	1,363,492
14	Storage Interest			23,110,026 2	0 0000	0				23,110,026.2	0 0000	0
15	Total Rate Schedule RSS	3,565,057		23,110,026.2		221,926,236	$8,739,061					230,665,297
16	Rate Schedule RDGSS - Residential Distributed Generation Sales Service											
17	RESIDENTIAL											
18		25 customers	110.47	2,761.8				25 Customers	110 47	2,761.8		
19	Customer Charge	295			18.73	5,525		295			18.73	5,525
20	Commodity Charge:											
21	First 2.1 Dth			548.0	0.0000	0				548.0	0.0000	0
22	Over 2.1 Dth			2,213.8	2.6708	5,913				2,213.8	2.6708	5,913
23	Rider USP - Universal Service Plan			2,761.8	0.3595	993				2,761.8	0 3595	993
24	Subtotal					12,431						12,431
25	STAS					(14)						(14)
26	Base Rate Revenue					12,417						12,417
27	Gas Cost			2,761.8	4.3212	11,934				2,761.8	4 3212	11,934
28	Unbundled Uncollectibles			2,761.8	0.0590	163				2,761.8	0 0590	163
29	Storage Interest			2,761.8	0.0000	0				2,761.8	0.0000	0
30	Total Rate Schedule RDGSS	295		2,761.8		24,514	$0	295		2,761.8		24,514
31	Residential Distribution Service (CAP)											
32	RESIDENTIAL											
33		18,370 customers	140.58	2,582,529.5				18,370 customers	140.58	2,582,529.5		
34	Customer Charge	224,703			18.73	4,208,687		224,703			18.73	4,208,687
35	Commodity Charge:											
36	First 2.1 Dth			411,203.9	0.0000	0				411,203.9	0.0000	0
37	Over 2.1 Dth			2,171,325.6	2.6708	5,799,176				2,171,325 6	2.6708	5,799,176
38	Subtotal			2,582,529.5		10,007,863				2,582,529.5		10,007,863
39	STAS					(11,609)						(11,609)
40	Base Rate Revenue					9,996,254						9,996,254
41	Gas Cost			2,582,529.5	0.8731	2,254,807				2,582,529.5	0 8731	2,254,807
42	Storage Interest			2,582,529.5	0.0000	0				2,582,529.5	0.0000	0
43	Total Rate Schedule RCC	224,703		2,582,529.5		12,251,061	$0	224,703		2,582,529.5		12,251,061

I&E Exhibit No. 3
Schedule 4
page 1 of 2

Columbia Gas of Pennsylvania, Inc.
BI&E Proposed Present Rate Revenues and Cost of Gas
Residential Customers
For the 12 Months Ended June 30, 2014

Line	Description	Per Company (A) Billing Units (Columbia Ex. No. 103 Schedule No. 1)	(B) Total Normal Usage (Dth/cust.)	(C) Total Consumption (Dth) (Columbia Ex. No. 103 Schedule No. 1)	(D) Base Rate	(E) Revenue ($)	(F) Increase to Present rate Revenues	Per BI&E (G) Billing Units	(H) Total Normal Usage (Dth/cust.)	(I) Total Consumption (Dth)	(J) Base Rate	(K) Revenue ($)
1	Rate Schedule RDS - Residential Distribution Service (Choice)											
2	RESIDENTIAL											
3		67,275 customers	105.38	7,089,719.1				67,275 customers	105 38	7,089,719.1		
4	Customer Charge	813,396			18.73	15,234,907		813,396			18.73	15,234,907
5	Commodity Charge:											
6	First 2.1 Dth			1,457,410.0	0.0000	0				1,457,410 0	0 0000	0
7	Over 2.1 Dth			5,632,309 1	2.6708	15,042,771				5,632,309 1	2 6708	15,042,771
8	Rider USP - Universal Service Plan			7,089,719.1	0.3595	2,548,754				7,089,719.1	0.3595	2,548,754
9	Subtotal					32,826,432						32,826,432
10	STAS					(38,079)						(38,079)
11	Base Rate Revenue					32,788,353						32,788,353
12	Gas Cost			7,089,719.1	0.8731	6,190,034				7,089,719.1	0.8731	6,190,034
13	Storage Interest			7,089,719 1	0.0000	0				7,089,719.1	0.0000	0
14	Total Rate Schedule RDS	813,396		7,089,719.1		38,978,387	$0	813,396		7,089,719.1		38,978,387
15	Rate Schedule RDGDS - Residential Distributed Generation Distribution Service (Choice)											
16	RESIDENTIAL											
17		5 customers	150.24	751.2				5 customers	150.24	751.2		
18	Customer Charge	60			18.73	1,124		60			18.73	1,124
19	Commodity Charge:											
20	First 2 1 Dth			112.3	0.0000	0				112.3	0 0000	0
21	Over 2.1 Dth			638.9	2.6708	1,706				638 9	2.6708	1,706
22	Rider USP - Universal Service Plan			751.2	0.3595	270				751.2	0 3595	270
23	Subtotal					3,100						3,100
24	STAS					(4)						(4)
25	Base Rate Revenue					3,096						3,096
26	Gas Cost			751.2	0.8731	656				751.2	0.8731	656
27	Storage Interest			751 2	0.0000	0				751.2	0 0000	0
28	Total Rate Schedule PRDGDS	60		751.2		3,752	$0	60		751.2		3,752
29	Total Residential	380,024 Customers	86.27	32,785,788		$273,183,950	$8,739,061	380,024	89.50	34,012,148		$281,923,011

I&E Exhibit No. 3
Schedule 5

Columbia Gas of Pennsylvania, Inc.
Residential Throughput Data
2000-2011
Docket No. R-2012-2321748

Usage per Customer

		(Dth)	Change
	(A)	(B)	(C)
1	2000	110.00	
			-2.00
2	2001	108.00	
			-3.00
3	2002	105.00	
			0.00
4	2003	105.00	
			-2.00
5	2004	103.00	
			-6.00
6	2005	97.00	
			-6.00
7	2006	91.00	
			3.00
8	2007	94.00	
			-2.00
9	2008	92.00	
			-2.00
10	2009	90.00	
			1.00
11	2010	91.00	
			-1.00
12	2011	90.00	
13	SIX YEAR AVERAGE	Residential (Dth)	**-0.20**
14	2012	89.80	
15	2013	89.60	
16	**2014 June**	**89.50**	

I&E Exhibit No. 3
Schedule 6

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Summary of Increase to Present Rate Revenues Per BI&E
Fully Projected Future Test Year Ending June 30, 2014

	Customer Class (A)	Company Claim (B) Co. Ex. No. 103 Schedule I pp. 21-25	BI&E Proposed Adjustment (C)	Adjusted Revenue Per BI&E (D)
	RESIDENTIAL CUSTOMERS			
	RSS - Residential Sales Service			
1	Non - Gas Revenues	$122,203,365	$3,443,708	$125,647,073
2	Gas Costs	$99,863,045	$5,299,348	$105,162,393
3	STAS	($140,174)	($3,995)	($144,169)
4	Total RSS Present Rate Revenue	$221,926,236	$8,739,061	$230,665,297
	RDGSS - Residential Distributed Generation Sales Service			
5	Non - Gas Revenues	$12,594	$0	$12,594
6	Gas Costs	$11,934	$0	$11,934
7	STAS	($14)	$0	($14)
8	Total RDGSS Present Rate Revenue	$24,514	$0	$24,514
	RCC - Residential Distribution Service (CAP)			
9	Non - Gas Revenues	$10,007,863	$0	$10,007,863
10	Gas Costs	$2,254,807	$0	$2,254,807
11	STAS	($11,609)	$0	($11,609)
12	Total RCC Present Rate Revenue	$12,251,061	$0	$12,251,061
	RDS - Residential Distribution Service (Choice)			
13	Non - Gas Revenues	$32,826,432	$0	$32,826,432
14	Gas Costs	$6,190,034	$0	$6,190,034
15	STAS	($38,079)	$0	($38,079)
16	Total RDS Present Rate Revenue	$38,978,388	$0	$38,978,388
	RDGDS - Residential Distribution Generation Service (Choice)			
17	Non - Gas Revenues	$3,100	$0	$3,100
18	Gas Costs	$656	$0	$656
19	STAS	($4)	$0	($4)
20	Total RDGDS Present Rate Revenue	$3,753	$0	$3,753
21	**Total Residential Present Rate Revenue (Lines 4+8+12+16+20)**	$273,183,952	$8,739,061	$281,923,013
22	**Total Residential Gas Cost (Lines 2+6+10+14+18)**	$108,320,476	$5,299,348	$113,619,824

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation & Enforcement – Set RS

Question No. I&E-RS-6-D:

Reference Columbia Statement No. 2, p. 12, and the Company's description of the residential annual Dth per customer:

A. For each data point depicted on the graph, provide the annual Dth per residential customer;

B. Provide the same information requested in subpart A for the SGS/SGSDS customers.

Response:

A. See I&E RS-6 Attachment A.

B. The company does not maintain a comparable history for SGS/SGSDS customers.

	Columbia Gas of Pennsylvania Residential Annual Dth per Customer Normalized for Weather
1991	119
1992	121
1993	120
1994	118
1995	116
1996	117
1997	114
1998	109
1999	108
2000	110
2001	108
2002	105
2003	105
2004	103
2005	97
2006	91
2007	94
2008	92
2009	90
2010	91
2011	90
TME July 2012	88

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

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 [PAGE 6]		456,618,492	336,152,969	89,807,740	6,170,570	10,112,142	12,871,575	1,503,496
2	PRODUCTS PURCHASED [PAGE 7]		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES		138,880,661	104,594,914	24,205,341	1,093,414	2,645,533	6,198,395	143,064
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	29,931,554	8,236,349	214,794	1,155,972	2,409,790	12,878
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,631,683	746,640	23,136	93,335	191,677	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		334,728,827	245,478,626	70,789,726	5,356,474	3,894,841	8,799,862	409,299
7	OPERATING INCOME BEFORE TAXES		121,889,665	90,674,342	19,018,014	814,097	6,217,302	4,071,713	1,094,197
8	INCOME TAXES		36,054,400	27,464,198	4,948,785	244,467	2,162,354	784,157	450,439
9	INVESTMENT TAX CREDIT	12	(360,239)	(251,962)	(72,545)	(1,935)	(10,724)	(22,972)	(101)
10	NET INCOME TAXES		35,694,161	27,212,236	4,876,240	242,533	2,151,629	761,184	450,338
11	OPERATING INCOME		86,195,504	63,462,106	14,141,773	571,564	4,065,672	3,310,529	643,860
12	RATE BASE [PAGE 10]		1,011,680,660	707,848,656	205,385,032	6,839,072	28,752,908	62,616,057	238,933
13	RATE OF RETURN EARNED ON RATE BASE		8.520%	8.965%	6.885%	8.357%	14.140%	5.287%	269.472%
14	UNITIZED RETURN		**1.00**	**1.05**	**0.81**	**0.98**	**1.66**	**0.62**	**31.63**
15	**Present Rate Revenue**		379,306,896	274,373,270	75,451,790	5,588,480	9,530,454	12,860,564	1,502,338
16	**Revenue Increase**		77,311,596	61,779,698	14,355,950	582,091	581,688	11,011	1,158
17	**Percent Increase**		20.38%	22.52%	19.03%	10.42%	6.10%	0.09%	0.08%

I&E Exhibit No. 3
Schedule 8
page 1 of 3

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

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 [PAGE 6]		456,418,492	336,152,969	89,807,740	6,170,570	9,912,142	12,871,575	1,503,496
2	PRODUCTS PURCHASED [PAGE 7]		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES		138,880,661	104,594,914	24,205,341	1,093,414	2,645,533	6,198,395	143,064
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	29,931,554	8,236,349	214,794	1,155,972	2,409,790	12,878
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,631,683	746,640	23,136	93,335	191,677	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		334,728,827	245,478,626	70,789,726	5,356,474	3,894,841	8,799,862	409,299
7	OPERATING INCOME BEFORE TAXES		121,689,665	90,674,342	19,018,014	814,097	6,017,302	4,071,713	1,094,197
8	INCOME TAXES		36,054,400	27,464,198	4,948,785	244,467	2,162,354	784,157	450,439
9	INVESTMENT TAX CREDIT	12	(360,239)	(251,962)	(72,545)	(1,935)	(10,724)	(22,972)	(101)
10	NET INCOME TAXES		35,694,161	27,212,236	4,876,240	242,533	2,151,629	761,184	450,338
11	OPERATING INCOME		85,995,504	63,462,106	14,141,773	571,564	3,865,672	3,310,529	643,860
12	RATE BASE [PAGE 10]		1,011,680,660	707,848,656	205,385,032	6,839,072	28,752,908	62,616,057	238,933
13	RATE OF RETURN EARNED ON RATE BASE		8.500%	8.965%	6.885%	8.357%	13.444%	5.287%	269.472%
14	UNITIZED RETURN		**1.00**	**1.05**	**0.81**	**0.98**	**1.58**	**0.62**	**31.70**
15	**Proposed Rate Revenue**		456,618,492	336,152,969	89,807,740	6,170,570	10,112,142	12,871,575	1,503,496
16	**First Dollar Relief**		(200,000)	0	0	0	**(200,000)**	0	0
17			456,418,492	336,152,969	89,807,740	6,170,570	10,312,142	12,871,575	1,503,496
18	**Present Rate Revenue**		379,306,896	274,373,270	75,451,790	5,588,480	9,530,454	12,860,564	1,502,338
19	**Revenue Increase**		77,111,596	61,779,698	14,355,950	582,091	381,688	11,011	1,158
20	**Percent Increase**		20.33%	22.52%	19.03%	10.42%	4.00%	0.09%	0.08%

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

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 [PAGE 6]		450,418,492	330,152,969	89,807,740	6,170,570	9,912,142	12,871,575	1,503,496
2	PRODUCTS PURCHASED [PAGE 7]		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES		138,880,661	104,594,914	24,205,341	1,093,414	2,645,533	6,198,395	143,064
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	29,931,554	8,236,349	214,794	1,155,972	2,409,790	12,878
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,631,683	746,640	23,136	93,335	191,677	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		334,728,827	245,478,626	70,789,726	5,356,474	3,894,841	8,799,862	409,299
7	OPERATING INCOME BEFORE TAXES		115,689,665	84,674,342	19,018,014	814,097	6,017,302	4,071,713	1,094,197
8	INCOME TAXES		36,054,400	27,464,198	4,948,785	244,467	2,162,354	784,157	450,439
9	INVESTMENT TAX CREDIT	12	(360,239)	(251,962)	(72,545)	(1,935)	(10,724)	(22,972)	(101)
10	NET INCOME TAXES		35,694,161	27,212,236	4,876,240	242,533	2,151,629	761,184	450,338
11	OPERATING INCOME		79,995,504	57,462,106	14,141,773	571,564	3,865,672	3,310,529	643,860
12	RATE BASE [PAGE 10]		1,011,680,660	707,848,656	205,385,032	6,839,072	28,752,908	62,616,057	238,933
13	RATE OF RETURN EARNED ON RATE BASE		7.907%	8.118%	6.885%	8.357%	13.444%	5.287%	269.472%
14	UNITIZED RETURN		**1.00**	**1.03**	**0.87**	**1.06**	**1.70**	**0.67**	**34.08**
15	**Proposed Rate Revenue**		456,618,492	336,152,969	89,807,740	6,170,570	10,112,142	12,871,575	1,503,496
16	**Second Dollar Relief**		(6,200,000)	**(6,000,000)**	0	0	**(200,000)**	0	0
17			450,418,492	330,152,969	89,807,740	6,170,570	10,312,142	12,871,575	1,503,496
18	**Present Rate Revenue**		379,306,896	274,373,270	75,451,790	5,588,480	9,530,454	12,860,564	1,502,338
19	**Revenue Increase**		71,111,596	55,779,698	14,355,950	582,091	381,688	11,011	1,158
20	**Percent Increase**		18.75%	20.33%	19.03%	10.42%	4.00%	0.09%	0.08%

I&E Exhibit No. 3
Schedule 8
page 3 of 3

Columbia Gas of Pennsylvania, Inc.
R-2012-2321748

BI&E Total Customer Costs

	Cost Function (A)	RS/RDS (B)	SGS/SGDS (C)	LGS (D)	SDS (E)	LDS (F)	MDS (G)
1	O and M Expense	$22,288,380	$3,607,793	$49,724	$153,170	$51,669	$1,212
2	Depreciation	$13,589,461	$2,110,167	$37,396	$110,346	$63,468	$6,569
3	Net Salvage Amortized	$1,397,607	$209,460	$4,733	$19,229	$29,043	$465
4	Subtotal Customer Costs	$37,275,448	$5,927,420	$91,853	$282,745	$144,180	$8,246
5	Rate Base	$305,800,785	$42,223,829	$616,393	$1,634,250	$702,289	$105,415
6	Return	$26,054,227	$3,597,470	$52,517	$139,238	$59,835	$8,981
7	Taxes	$12,765,412	$1,762,600	$25,731	$68,220	$29,317	$4,400
8	Taxes and Return	$38,819,638	$5,360,071	$78,247	$207,459	$89,152	$13,382
9	Total Direct Customer Costs	$76,095,086	$11,287,491	$170,100	$490,204	$233,332	$21,628
10	Average Annual Cust. Bills	4,603,511	439,658	945	5,028	1,101	108
11	**Cost per Bill**	**$16.53**	**$25.67**	**$180.00**	**$97.49**	**$211.93**	**$200.26**

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014
Customer Costs - Rate Base

Company

	Acct No	Gross Plant	Total A	RS/RDS B	SGS/SGDS C	LGS D	SDS E	LDS F	MDS G
1	303.30	Customer & Other-Based Software	$12,725,296	$10,710,373	$1,605,169	$36,267	$147,359	$222,565	$3,563
2	380.00	Services	$370,945,093	$339,221,869	$30,847,794	$270,790	$415,459	$189,182	$0
3	380.00	Direct - Services	$37,326	$0	$0	$0	$0	$0	$37,326
4	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$34,301,875	$25,721,261	$8,124,056	$94,673	$278,874	$78,551	$4,459
6	381.10	Automatic Meter Reading	$20,548,041	$15,407,948	$4,866,598	$56,713	$167,056	$47,055	$2,671
7	382.00	Meter Installations	$35,468,816	$26,596,292	$8,400,434	$97,894	$288,361	$81,224	$4,611
8	383.00	House Regulators	$10,741,363	$8,054,411	$2,543,984	$29,646	$87,327	$24,598	$1,396
9	384.00	House Reg Installations	$3,864,772	$2,897,999	$915,333	$10,667	$31,421	$8,850	$502
10	385.00	Ind M&R Equipment	$5,355,556	$0	$3,583,135	$317,263	$1,044,869	$410,289	$0
11	385.00	Direct - Ind M&R Equipment	$122,846	$0	$0	$0	$0	$0	$122,846
12	385.10	Ind. M&R Equipment - LG Volume	$1,356,628	$0	$907,652	$80,367	$264,678	$103,931	$0
13		Total Gross Plant	$495,467,613	$428,610,153	$61,794,155	$994,279	$2,725,404	$1,166,246	$177,376
		Depreciation Reserve	**Total**	**RS/RDS**	**SGS/SGDS**	**LGS**	**SDS**	**LDS**	**MDS**
14	303.30	Customer & Other-Based Software	$4,671,864	$3,932,121	$589,309	$13,315	$54,100	$81,711	$1,308
15	380.00	Services	$100,860,024	$92,234,475	$8,387,520	$73,628	$112,963	$51,439	$0
16	380.00	Direct - Services	$21,692	$0	$0	$0	$0	$0	$21,692
17	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
18	381.00	Meters	$14,998,136	$11,246,352	$3,552,159	$41,395	$121,935	$34,346	$1,950
19	381.10	Automatic Meter Reading	$4,440,562	$3,329,755	$1,051,703	$12,256	$36,102	$10,169	$577
20	382.00	Meter Installations	$10,435,222	$7,824,851	$2,471,478	$28,801	$84,838	$23,897	$1,357
21	383.00	House Regulators	$2,868,259	$2,150,764	$679,318	$7,916	$23,319	$6,568	$373
22	384.00	House Reg Installations	$2,788,621	$2,091,048	$660,457	$7,697	$22,672	$6,386	$363
23	385.00	Ind. M&R Equipment	$3,181,978	$0	$2,128,902	$188,500	$620,804	$243,771	$0
24	385.00	Direct - Ind M&R Equipment	$44,342	$0	$0	$0	$0	$0	$44,342
		Total 385	$3,226,320						
25	385.10	Ind M&R Equipment - LG Volume	$73,950	$0	$49,476	$4,381	$14,428	$5,665	$0
26			$144,384,650	$122,809,366	$19,570,322	$377,889	$1,091,160	$463,952	$71,961
27		Total Cust.-Based Rate Base	$351,082,963	$305,800,787	$42,223,833	$616,391	$1,634,243	$702,294	$105,415

BI&E

	Acct No	Gross Plant	Total H	RS/RDS I	SGS/SGDS J	LGS K	SDS L	LDS M	MDS N
1	303.30	Customer & Other-Based Software	$12,725,296	$10,710,373	$1,605,169	$36,267	$147,359	$222,565	$3,563
2	380.00	Services	$370,945,093	$339,221,869	$30,847,794	$270,791	$415,458	$189,183	$0
3	380.00	Direct - Services	$37,326	$0	$0	$0	$0	$0	$37,326
4	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$34,301,875	$25,721,260	$8,124,057	$94,674	$278,875	$78,552	$4,460
6	381.10	Automatic Meter Reading	$20,548,041	$15,407,947	$4,866,599	$56,713	$167,057	$47,056	$2,670
7	382.00	Meter Installations	$35,468,816	$26,596,291	$8,400,434	$97,893	$288,360	$81,225	$4,612
8	383.00	House Regulators	$10,741,363	$8,054,411	$2,543,983	$29,645	$87,327	$24,597	$1,397
9	384.00	House Reg Installations	$3,864,772	$2,898,000	$915,333	$10,667	$31,421	$8,850	$503
10	385.00	Ind M&R Equipment	$5,355,556	$0	$3,583,134	$317,263	$1,044,869	$410,289	$0
11	385.00	Direct - Ind M&R Equipment	$122,846	$0	$0	$0	$0	$0	$122,846
12	385.10	Ind. M&R Equipment - LG Volume	$1,356,628	$0	$907,647	$80,370	$264,685	$103,926	$0
13		Total Gross Plant	$495,467,612	$428,610,151	$61,794,151	$994,282	$2,725,411	$1,166,241	$177,377
		Depreciation Reserve	**Total**	**RS/RDS**	**SGS/SGDS**	**LGS**	**SDS**	**LDS**	**MDS**
14	303.30	Customer & Other-Based Software	$4,671,864	$3,932,122	$589,309	$13,315	$54,100	$81,711	$1,308
15	380.00	Services	$100,860,024	$92,234,476	$8,387,520	$73,628	$112,963	$51,439	$0
16	380.00	Direct - Services	$21,692	$0	$0	$0	$0	$0	$21,692
17	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
18	381.00	Meters	$14,998,136	$11,246,351	$3,552,159	$41,395	$121,935	$34,346	$1,950
19	381.10	Automatic Meter Reading	$4,440,562	$3,329,755	$1,051,703	$12,256	$36,102	$10,169	$577
20	382.00	Meter Installations	$10,435,222	$7,824,851	$2,471,478	$28,801	$84,838	$23,897	$1,357
21	383.00	House Regulators	$2,868,259	$2,150,765	$679,318	$7,916	$23,319	$6,568	$373
22	384.00	House Reg Installations	$2,788,621	$2,091,047	$660,457	$7,697	$22,672	$6,386	$363
23	385.00	Ind. M&R Equipment	$3,181,978	$0	$2,128,903	$188,500	$620,804	$243,771	$0
24	385.00	Direct - Ind M&R Equipment	$44,342	$0	$0	$0	$0	$0	$44,342
		Total 385	$3,226,320						
25	385.10	Ind M&R Equipment - LG Volume	$73,950	$0	$49,476	$4,381	$14,428	$5,665	$0
26			$144,384,650	$122,809,366	$19,570,322	$377,889	$1,091,161	$463,952	$71,962
27		Total Cust.-Based Rate Base	$351,082,962	$305,800,785	$42,223,829	$616,393	$1,634,250	$702,289	$105,415

Columbia Gas of Pennsylvania, Inc.
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	Item		COMPANY						BI&E					
			RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
1	Total Rate Base		$305,800,787	$42,223,833	$616,391	$1,634,243	$702,294	$105,415	$305,800,785	$42,223,829	$616,393	$1,634,250	$702,289	$105,415
2	Rate of Return	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%
3	Total Income	$29,912,268	$26,054,227	$3,597,471	$52,517	$139,238	$59,835	$8,981	$26,054,227	$3,597,470	$52,517	$139,238	$59,835	$8,981
4		49.00%												
5	Income Taxes	$14,655,680	$12,765,412	$1,762,600	$25,731	$68,220	$29,317	$4,400	$12,765,412	$1,762,600	$25,731	$68,220	$29,317	$4,400

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014
Customer Costs - Depreciation

Company

	Acct No	Depreciation Expense	Total A	RS/RDS B	SGS/SGDS C	LGS D	SDS E	LDS F	MDS G
1	303.30	Customer & Other-Based Software	$1,756,935	$1,478,742	$221,620	$5,007	$20,345	$30,729	$492
2	380.00	Services	$10,226,751	$9,352,160	$850,457	$7,466	$11,454	$5,216	$0
3	380 00	Direct - Services	$956	$0	$0	$0	$0	$0	$956
4	380 12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$835,931	$626,823	$197,982	$2,307	$6,796	$1,914	$109
6	381.10	Automatic Meter Reading	$1,778,260	$1,333,428	$421,163	$4,908	$14,457	$4,072	$231
7	382 00	Meter Installations	$707,167	$530,269	$167,485	$1,952	$5,749	$1,619	$92
8	383 00	House Regulators	$284,993	$213,702	$67,498	$787	$2,317	$653	$37
9	384 00	House Reg. Installations	$72,465	$54,338	$17,163	$200	$589	$166	$9
10	385 00	Ind. M&R Equipment	$245,096	$0	$163,982	$14,520	$47,818	$18,777	$0
11	385 00	Direct - Ind. M&R Equipment	$4,644	$0	$0	$0	$0	$0	$4,644
12	385.10	Ind. M&R Equipment - LG Volume	$4,212	$0	$2,818	$250	$822	$323	$0
13		**Total Depreciation Expense**	$15,917,410	$13,589,462	$2,110,167	$37,395	$110,348	$63,468	$6,569
14		**Total Net Salvage Amortized**	$1,660,536	$1,397,607	$209,460	$4,733	$19,229	$29,043	$465

BI&E

	Acct No	Depreciation Expense	Total H	RS/RDS I	SGS/SGDS J	LGS K	SDS L	LDS M	MDS N
1	303.30	Customer & Other-Based Software	$1,756,935	$1,478,742	$221,620	$5,007	$20,345	$30,729	$492
2	380.00	Services	$10,226,751	$9,352,160	$850,457	$7,466	$11,454	$5,216	$0
3	380 00	Direct - Services	$956	$0	$0	$0	$0	$0	$956
4	380 12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$835,931	$626,823	$197,982	$2,307	$6,796	$1,914	$109
6	381.10	Automatic Meter Reading	$1,778,260	$1,333,428	$421,163	$4,908	$14,457	$4,072	$231
7	382 00	Meter Installations	$707,167	$530,269	$167,485	$1,952	$5,749	$1,619	$92
8	383 00	House Regulators	$284,993	$213,702	$67,498	$787	$2,317	$653	$37
9	384 00	House Reg. Installations	$72,465	$54,338	$17,163	$200	$589	$166	$9
10	385 00	Ind. M&R Equipment	$245,096	$0	$163,982	$14,520	$47,818	$18,777	$0
11	385 00	Direct - Ind. M&R Equipment	$4,644	$0	$0	$0	$0	$0	$4,644
12	385.10	Ind. M&R Equipment - LG Volume	$4,212	$0	$2,818	$250	$822	$323	$0
13		**Total Depreciation Expense**	$15,917,410	$13,589,461	$2,110,167	$37,396	$110,346	$63,468	$6,569
14		**Total Net Salvage Amortized**	$1,660,536	$1,397,607	$209,460	$4,733	$19,229	$29,043	$465

I&E Exhibit No. 3
Schedule 9
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Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014
Customer Costs - Expenses

Company

	Acct. No.	Customer Costs - Details	Total A	RS/RDS B	SGS/SGDS C	LGS D	SDS E	LDS F	MDS G
		Distribution							
1	874.00	Mains & Services (Services Only)	$3,137,845	$2,869,497	$260,943	$2,291	$3,514	$1,600	$0
2	876.00	M & R - Industrial	$245,982	$0	$164,574	$14,572	$47,991	$18,845	$0
3	878.00	Meters & House Regulators	$2,455,745	$1,841,440	$581,619	$6,778	$19,965	$5,624	$319
4	879.00	Customer Installations	$4,813,089	$3,609,095	$1,139,932	$13,284	$39,130	$11,022	$626
5	890.00	M &R - Industrial	$127,109	$0	$85,042	$7,530	$24,799	$9,738	$0
6	892.00	Services	$2,984,103	$2,728,903	$248,158	$2,178	$3,342	$1,522	$0
7	893.00	Meters & House Regulators	$286,063	$214,504	$67,751	$790	$2,326	$655	$37
8		Total Distribution	$14,049,936	$11,263,439	$2,548,019	$47,423	$141,067	$49,006	$982
		Customer Accounts							
9	901.00	Supervision	$0	$0	$0	$0	0	$0	$0
10	902.00	Meter Reading	$2,126,148	$1,936,920	$186,187	$404	$2,126	$468	$43
11	903.00	Collecting - Delinquent Accts	$1,072,108	$976,690	$93,885	$204	$1,072	$236	$21
12	903.00	Collecting - Current Accts	$7,960	$7,251	$697	$2	$8	$2	$0
13	903.00	Billing & Accounting	$5,797,611	$5,281,623	$507,697	$1,102	$5,798	$1,275	$116
14	903.00	Rendering Bills	$2,484,721	$2,263,580	$217,587	$472	$2,485	$547	$50
15	904.00	Uncollectibles - Dis Revenue	$3,037,943	$2,399,671	$638,272	$0	$0	$0	$0
16	904.00	Uncollectibles - GMB/GTS Revenue	$38,961	$0	$3,480	$6,792	$11,573	$15,621	$1,495
17	905.00	Miscellaneous	$17,447	$15,895	$1,528	$3	$17	$4	$0
18	921.00	Office Supplies & Expenses	$4,212	$3,837	$369	$1	$4	$1	$0
19		Total Customer Accounts	$14,587,111	$12,885,467	$1,649,702	$8,980	$23,083	$18,154	$1,725
		Cust. Service & Information							
20	907.00	Supervision	$0	$0	$0	$0	$0	$0	$0
21	908.00	Customer Assistance	$613,464	$558,877	$53,721	$117	$614	$135	$0
22	909.00	Informational & Instructional Expense	$38,184	$34,786	$3,344	$7	$38	$8	$1
23	910.00	Miscellaneous	$600,791	$547,321	$52,611	$114	$601	$132	$12
24	910.00	Large Customer Relations	$986,405	$0	$113,091	$257,600	$0	$552,890	$62,824
25	921.00	Office Supplies & Expenses	$9,085	$8,276	$796	$2	$9	$2	$0
26	931.00	Rents - General	$140	$128	$12	$0	$0	$0	$0
27		Total Cust. Service & Information	$2,248,069	$1,149,388	$223,575	$257,840	$1,262	$553,167	$62 837
		Sales							
28	912.00	Demonstration	$650,917	$592,985	$57,001	$124	$651	$143	$13
29	913.00	Advertising	$128,866	$117,396	$11,285	$25	$129	$28	$3
30		Total Sales	$779,783	$710,381	$68,286	$149	$780	$171	$16
31		Customer Related Benefits	$3,715,748	$3,033,017	$566,243	$14,863	$43,994	$56,442	$1,189
32		Total Customer Related O&M	$35,380,646	$29,041,693	$5,055,824	$329,252	$210,187	$676,941	$66,749

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014
Customer Costs - Expenses

	Acct. No.	Customer Costs - Details	BI&E Adjustment						BI&E					
			RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
			H	I	J	K	L	M	N	O	P	Q	R	S
		Distribution												
1	874.00	Mains & Services (Services Only)	$0	$0	$0	$0	$0	$0	$2,869,497	$260,943	$2,291	$3,514	$1,600	$0
2	876.00	M & R - Industrial	$0	$0	$0	$0	$0	$0	$0	$164,574	$14,572	$47,991	$18,845	$0
3	878.00	Meters & House Regulators	$0	$0	$0	$0	$0	$0	$1,841,440	$581,619	$6,778	$19,965	$5,624	$319
4	879.00	Customer Installations	$0	$0	$0	$0	$0	$0	$3,609,095	$1,139,932	$13,284	$39,130	$11,022	$626
5	890.00	M &R - Industrial	$0	$0	$0	$0	$0	$0	$0	$85,042	$7,530	$24,799	$9,738	$0
6	892.00	Services	$0	$0	$0	$0	$0	$0	$2,728,903	$248,158	$2,178	$3,342	$1,522	$0
7	893.00	Meters & House Regulators	$0	$0	$0	$0	$0	$0	$214,504	$67,751	$790	$2,326	$655	$37
8		Total Distribution	$0	$0	$0	$0	$0	$0	$11,263,439	$2,548,019	$47,423	$141,067	$49,006	$982
		Customer Accounts												
9	901.00	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	902.00	Meter Reading	$0	$0	$0	$0	$0	$0	$1,936,920	$186,187	$404	$2,126	$468	$43
11	903.00	Collecting - Delinquent Accts	$0	$0	$0	$0	$0	$0	$976,690	$93,885	$204	$1,072	$236	$21
12	903.00	Collecting - Current Accts	$0	$0	$0	$0	$0	$0	$7,251	$697	$2	$8	$2	$0
13	903.00	Billing & Accounting	$0	$0	$0	$0	$0	$0	$5,281,623	$507,697	$1,102	$5,798	$1,275	$116
14	903.00	Rendering Bills	$0	$0	$0	$0	$0	$0	$2,263,580	$217,587	$472	$2,485	$547	$50
15	904.00	Uncollectibles - Dis Revenue	($2,399,671)	($638,272)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	904.00	Uncollectibles - GMB/GTS Revenue	$0	($3,480)	($6,792)	($11,573)	($15,621)	($1,495)	$0	$0	$0	$0	$0	$0
17	905.00	Miscellaneous	($15,895)	($1,528)	($3)	($17)	($4)	$0	$0	$0	$0	$0	$0	$0
18	921.00	Office Supplies & Expenses	($3,837)	($369)	($1)	($4)	($1)	$0	$0	$0	$0	$0	$0	$0
19		Total Customer Accounts	($2,419,403)	($643,649)	($6,796)	($11,594)	($15,626)	($1,495)	$10,466,064	$1,006,053	$2,184	$11,489	$2,528	$230
		Cust. Service & Information												
20	907.00	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	908.00	Customer Assistance	$0	$0	$0	$0	$0	$0	$558,877	$53,721	$117	$614	$135	$0
22	909.00	Informational & Instructional Expenses	($34,786)	($3,344)	($7)	($38)	($8)	($1)	$0	$0	$0	$0	$0	$0
23	910.00	Miscellaneous	($547,321)	($52,611)	($114)	($601)	($132)	($12)	$0	$0	$0	$0	$0	$0
24	910.00	Large Customer Relations	$0	($113,091)	($257,600)	$0	($552,890)	($62,824)	$0	$0	$0	$0	$0	$0
25	921.00	Office Supplies & Expenses	($8,276)	($796)	($2)	($9)	($2)	$0	$0	$0	$0	$0	$0	$0
26	931.00	Rents - General	($128)	($12)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27		Total Cust. Service & Information	($590,511)	($169,854)	($257,723)	($648)	($553,032)	($62,837)	$558,877	$53,721	$117	$614	$135	$0
		Sales												
28	912.00	Demonstration	($592,985)	($57,001)	($124)	($651)	($143)	($13)	$0	$0	$0	$0	$0	$0
29	913.00	Advertising	($117,396)	($11,285)	($25)	($129)	($28)	($3)	$0	$0	$0	$0	$0	$0
30		Total Sales	($710,381)	($68,286)	($149)	($780)	($171)	($16)	$0	$0	$0	$0	$0	$0
31		Customer Related Benefits	($3,033,017)	($566,243)	($14,863)	($43,994)	($56,442)	($1,189)	$0	$0	$0	$0	$0	$0
32		Total Customer Related O&M	($6,753,312)	($1,448,032)	($279,531)	($57,016)	($625,271)	($65,537)	$22,288,380	$3,607,793	$49,724	$153,170	$51,669	$1,212

Columbia Gas of Pennsylvania, Inc.

R-2012-2321748

Residential Monthly Bill Comparison

(Includes Rider USP, PGC, Unbundled Uncollectibles and Gas Procurement Charge)

			Company Option 1 Revenue Normalization Adj. Exhibit No. 111, Schedule 6			Company Option 2 Weather Normalization Adj. Exhibit PAS-3			Company Option 3 Levelized Distribution Charge Exhibit PAS-4			BI&E Revenue Normalization Adj.		
	Usage THM	Current Bill	Increase	Proposed Bill	Percent Increase	Increase	Proposed Bill	Percent Increase	Increase	Proposed Bill	Percent Increase	Increase	Proposed Bill	Percent Increase
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
1	0	$18.71	$0.29	$19.00	1.6%	$10.29	$29.00	55.0%	$27.78	$46.49	148.5%	($2.18)	$16.53	-11.6%
2	1	$19.18	$0.69	$19.88	3.6%	$10.55	$29.73	55.0%	$27.78	$46.97	144.8%	($1.74)	$17.44	-9.1%
3	3	$20.13	$1.50	$21.63	7.4%	$11.06	$31.19	55.0%	$27.79	$47.92	138.1%	($0.87)	$19.26	-4.3%
4	5	$21.08	$2.30	$23.38	10.9%	$11.58	$32.65	54.9%	$27.80	$48.87	131.9%	$0.00	$21.08	0.0%
5	7	$22.03	$3.10	$25.13	14.1%	$12.09	$34.11	54.9%	$27.80	$49.83	126.2%	$0.88	$22.90	4.0%
6	8	$22.50	$3.51	$26.01	15.6%	$12.35	$34.85	54.9%	$27.81	$50.31	123.6%	$1.31	$23.81	5.8%
7	10	$23.45	$4.31	$27.76	18.4%	$12.86	$36.31	54.8%	$27.81	$51.26	118.6%	$2.19	$25.63	9.3%
8	15	$25.82	$6.32	$32.14	24.5%	$14.14	$39.96	54.8%	$27.83	$53.64	107.8%	$4.37	$30.19	16.9%
9	21	$28.66	$8.73	$37.39	30.5%	$15.68	$44.34	54.7%	$27.84	$56.50	97.2%	$6.99	$35.65	24.4%
10	25	$31.62	$9.27	$40.89	29.3%	$15.64	$47.27	49.5%	$26.79	$58.41	84.7%	$7.67	$39.29	24.2%
11	30	$35.33	$9.94	$45.27	28.1%	$15.59	$50.92	44.1%	$25.47	$60.80	72.1%	$8.51	$43.84	24.1%
12	35	$39.03	$10.62	$49.65	27.2%	$15.54	$54.57	39.8%	$24.15	$63.18	61.9%	$9.36	$48.39	24.0%
13	40	$42.73	$11.29	$54.03	26.4%	$15.49	$58.23	36.3%	$22.83	$65.57	53.4%	$10.21	$52.94	23.9%
14	45	$46.44	$11.97	$58.41	25.8%	$15.44	$61.88	33.3%	$21.51	$67.95	46.3%	$11.06	$57.50	23.8%
15	50	$50.14	$12.64	$62.78	25.2%	$15.39	$65.53	30.7%	$20.19	$70.34	40.3%	$11.91	$62.05	23.7%
16	60	$57.55	$13.99	$71.54	24.3%	$15.29	$72.84	26.6%	$17.56	$75.10	30.5%	$13.60	$71.15	23.6%
17	70	$64.95	$15.34	$80.30	23.6%	$15.19	$80.15	23.4%	$14.92	$79.87	23.0%	$15.30	$80.26	23.6%
18	73	$67.18	$15.75	$82.92	23.4%	$15.16	$82.34	22.6%	$14.13	$81.30	21.0%	$15.81	$82.99	23.5%
19	80	$72.36	$16.69	$89.05	23.1%	$15.09	$87.46	20.9%	$12.28	$84.64	17.0%	$17.00	$89.36	23.5%
20	90	$79.77	$18.04	$97.81	22.6%	$14.99	$94.76	18.8%	$9.64	$89.41	12.1%	$18.69	$98.46	23.4%
21	100	$87.18	$19.39	$106.57	22.2%	$14.89	$102.07	17.1%	$7.00	$94.18	8.0%	$20.39	$107.57	23.4%
22	150	$124.21	$26.14	$150.35	21.0%	$14.39	$138.60	11.6%	($6.19)	$118.03	-5.0%	$28.87	$153.08	23.2%
23	200	$161.25	$32.89	$194.14	20.4%	$13.89	$175.14	8.6%	($19.38)	$141.87	-12.0%	$37.36	$198.60	23.2%
24	250	$198.28	$39.64	$237.92	20.0%	$13.39	$211.67	6.8%	($32.57)	$165.72	-16.4%	$45.84	$244.12	23.1%
25	300	$235.32	$46.39	$281.70	19.7%	$12.89	$248.21	5.5%	($45.76)	$189.56	-19.4%	$54.32	$289.64	23.1%
26	350	$272.35	$53.14	$325.49	19.5%	$12.39	$284.74	4.5%	($58.95)	$213.41	-21.6%	$62.81	$335.16	23.1%
27	400	$309.39	$59.89	$369.27	19.4%	$11.89	$321.28	3.8%	($72.14)	$237.25	-23.3%	$71.29	$380.67	23.0%
28	450	$346.42	$66.64	$413.06	19.2%	$11.39	$357.81	3.3%	($85.33)	$261.10	-24.6%	$79.77	$426.19	23.0%
29	500	$383.46	$73.38	$456.84	19.1%	$10.89	$394.35	2.8%	($98.52)	$284.94	-25.7%	$88.26	$471.71	23.0%
30	600	$457.53	$86.88	$544.41	19.0%	$9.89	$467.41	2.2%	($124.90)	$332.63	-27.3%	$105.22	$562.75	23.0%
31	700	$531.60	$100.38	$631.98	18.9%	$8.89	$540.48	1.7%	($151.28)	$380.32	-28.5%	$122.19	$653.78	23.0%
32	800	$605.66	$113.88	$719.54	18.8%	$7.89	$613.55	1.3%	($177.65)	$428.01	-29.3%	$139.15	$744.82	23.0%
33	900	$679.73	$127.38	$807.11	18.7%	$6.89	$686.62	1.0%	($204.03)	$475.70	-30.0%	$156.12	$835.86	23.0%
34	1,000	$753.80	$140.88	$894.68	18.7%	$5.89	$759.69	0.8%	($230.41)	$523.39	-30.6%	$173.09	$926.89	23.0%

I&E Exhibit No. 3
Schedule 10

Question No. I&E-RS-15-D
Respondent: M.R. Kempic
Page 1 of 1
CONFIDENTIAL

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Bureau of Investigation & Enforcement – Set RS

Question No. I&E-RS-15-D:

Reference Columbia Statement No. 1, p. 20, lns. 14-17. Provide the "slide" identifying the recovery mechanisms referred to in the quotation attributed to Mr. Cortright.

Response:

Please see **CONFIDENTIAL** I&E-RS-15-D Attachment A to this response.

Characteristics Of Credit-Supportive Regulation

- Consistency And Predictability Of Decisions → Consistency And Predictability Of Cash Flows
- Timeliness Of Rate Orders
- *Use Of Forward-Looking Measures*
- *Use Of Adjustment Clauses/Trackers*
  - *Pass-Through Of Purchased Power, Gas, And Water Costs*
  - *Construction Work In Progress (CWIP)/Infrastructure Surcharges*
  - *Pre-Approval Of Significant Capital Outlays*
  - *Environmental*
  - *Conservation*
  - *Demand Response*
  - *Bad Debt*
  - *Pensions*

STANDARD
&POOR'S

I&E Statement No. 3-SR
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Surrebuttal Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

RECEIVED
2013 FEB 19 AM 11:48
PA PUC
SECRETARY'S BUREAU

Concerning:

Test Year
Rate Base
Annual Depreciation Expense
Cost of Service
Scaleback
Customer Cost Analysis
Residential Rate Design
Tariff Language
Forfeited Discounts

2-13-13
Hbg SR

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremy B. Hubert. My business address is Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. ARE YOU THE SAME JEREMY B. HUBERT WHO SUBMITTED I&E STATEMENT NO. 3 AND I&E EXHIBIT NO. 3 ON JANUARY 4, 2013?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to present a response to the rebuttal testimonies of Columbia Gas of Pennsylvania, Inc,'s ("Columbia" or "Company") witnesses John E Skirtich, Shirley Barnes Hasson, Paula A. Strauss, and Amy L. Efland and the Office of Small Business Advocate's ("OSBA") witness Robert D. Knecht. I will describe the Bureau of Investigation and Enforcement's ("I&E") positions concerning present rate revenue, cost of service, residential rate design, tariff language and the scaleback of rates.

PRESENT RATE REVENUE

Q. DID THE COMPANY PROJECT A LEVEL OF RESIDENTIAL USAGE FOR THE FULLY PROJECTED FUTURE TEST YEAR ("FPFTY")?

A. Yes. The Company proposed the average residential customer will use 86.27 Dth per year on a composite basis (I&E Ex. No. 3, Sch. 4, p. 2, col. B, ln. 29).

Q. DID YOU RECOMMEND AN ADJUSTMENT TO THIS 86.27 DTH PER YEAR PROJECTION?

A. Yes. In my Direct Testimony, I recommended that the residential class usage be 89.50 Dth per year on a composite basis (I&E St. No. 3, p. 16). This higher average usage per customer will increase present rate revenue by $8,739,061. If the Commission accepts this recommendation there should be a corresponding increase of $5,299,348 to the cost of purchased gas (I&E St. No. 3, pp. 19-20).

Q. WHAT WAS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation was based on the level of annual Dth usage per residential customers for the period 2007-2011 (I&E Ex. No. 3, Sch. 7).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION TO INCREASE THE AVERAGE USAGE PER RESIDENTIAL CUSTOMER TO 89.50 DTH ON A COMPOSITE BASIS?

A. Yes. The Company disagrees with my recommendation. First, Company witness Efland states that the data I utilized was a "concept chart" that was not intended to be used to determine current levels of usage. Second, Ms. Efland believes that since I did not object to the Company's using 20 years' worth of data to determine normal Heating Degree Days, that 20 years' worth of data should be used to determine the decline in usage based on non-weather factors. Third, Ms. Efland states that my analysis of projected usage for the year ending May 31, 2013, is inaccurate and its data validates its projected average use per customer for May 31, 2014. Finally, Ms. Efland believes I used a time period that is too limited (Columbia St. No. 102-R, pp. 1-4).

Q. PLEASE ADDRESS MS. EFLAND'S CLAIM THAT THE USAGE DATA THAT YOU RELIED UPON WAS ONLY INTENDED TO BE "CONCEPT CHART" AND NOT INTENDED TO BE USED TO DETERMINE CURRENT USAGE LEVELS.

A. First, I am not sure what the significance is, if any, of the Company's description of the usage data I relied on as a "concept chart," since to my knowledge, that term has no specific import within the ratemaking context. Second, the "concept chart" which the Company claims displays "long term" data, also includes short term data. For reasons stated in my Direct Testimony, I believe the short term data is more reflective of recent trends in customers' usage. Therefore, the Company's claim that the more recent trend reflected in the "concept chart" cannot be used is not valid.

Q. PLEASE ADDRESS THE COMPANY'S CLAIM THAT THE DECLINE IN USAGE SHOULD BE BASED ON THE SAME 20-YEAR TIME PERIOD THAT IS USED TO NORMALIZE WEATHER.

A. First, they are two different things that can be determined separately. Second, I am not aware of any requirement that the time period used to normalize weather must be the same time period used to determine recent trends in customer usage patterns other than weather, which is what is reflected on I&E Exhibit No. 3, Schedule 7. In my opinion, it is reasonable to base normalized weather on a longer time period, while a shorter time period should be used to capture non-weather usage trends such as the size of households, the use of higher efficient appliances and better insulation of homes.

Q. PLEASE ADDRESS THE COMPANY'S CLAIM THAT YOU MADE AN INCORRECT COMPARISON CONCERNING THE AVERAGE USAGE PER CUSTOMER FOR THE YEAR ENDING MAY 31, 2013.

A. I accept the Company's explanation concerning my comparison of weather normalized and non-weather normalized data and that in order to make a valid comparison based on weather normalized data I should have used 86.63 Dth per residential customer for the year ending May 2012 (Columbia Ex. No. 10, Sch. 8, p. 1). However, this does not change my opinion that the average use per customer will not decline at the rate projected by the Company. My opinion is based upon data from 2007 through 2011 which indicates that average usage per customer will not decline at the rate projected by the Company for the year ending June 30, 2014.

Q. WHY SHOULD THE LOWER LEVEL OF WEATHER NORMALIZED SALES EXPERIENCED IN THE YEAR ENDING MAY 2012 NOT BE USED TO PROJECT SALES?

A. The Company itself explains that the historic test year sales occurred during an extremely warm winter. Normalizing sales is not an exact science, and sales vary for a number of weather reasons not captured by the Heating Degree Days such as wind, humidity and sunlight. Therefore, I believe that the one year where weather normalized sales were 86.63 Dth should not be used because it represents one extremely warm year that is clearly an outlier from the other data.

Q. PLEASE ADDRESS THE COMPANY'S CLAIM THAT THE TIME PERIOD YOU USED TO DETERMINE AVERAGE USAGE IS IN "ERROR."

A. First, the historic time period selected to determine projected usage is a matter of judgment. This is evident by the Company's failure to cite any authority that 20 years of data must be used. Therefore, in the exercise of informed judgment the selection of any one time period is not an "error" so long as that judgment is justified. In rebuttal testimony, Company witness Efland asserts that customer usage patterns as far back 1991 should be used to project average usage in 2014-2015, or 23 year later. As stated in my direct testimony, I believe data from that far back is stale and not representative of current usage trends. Therefore, I did not make an error in my selection of the time period to project the average use per customer in 2014.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING AVERAGE USE PER RESIDENTIAL CUSTOMER.

A. The Company did not provide any valid argument for projecting a lower average use per residential customer. Therefore, as described above, present rate revenue should be increased by $8,739,061. If the Commission accepts this recommendation there should be a corresponding increase of $5,299,348 to the cost of purchased gas (I&E St. No. 3, pp. 19-20).

CUSTOMER COST ANALYSIS

Q. DID YOU CONDUCT A CUSTOMER COST ANALYSIS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I conducted a customer cost analysis and attached the analysis as I&E Exhibit No. 3, Schedule 9.

Q. WAS YOUR CUSTOMER COST ANALYSIS BASED ON ONE OF THE CUSTOMER COST ANALYSES PROVIDED BY THE COMPANY?

A. Yes. The customer cost analysis that I prepared was based on the Company customer cost analysis that excludes mains (Columbia Ex. No. 111, Sch. 1, pp. 17-18).

Q. **WHAT ITEMS DID YOU EXCLUDE AND WHERE ARE THE RESULTS OF YOU CUSTOMER COST ANALYSIS SHOWN?**

A. The difference between my analysis and the Company's analysis is that I excluded uncollectible expense, miscellaneous, office supplies and expense, informational and instructional expense, office supplies and expense, rents, demonstration expense, advertising, and employee benefits (I&E Ex. No. 3, Sch. 9, p. 6). The results of my customer cost analysis are shown on I&E Exhibit No. 3, Schedule 9, which accompanied my direct testimony.

Q. **WHAT DID THE COMPANY PROVIDE WITH RESPECT TO CUSTOMER COST ANALYSES IN REBUTTAL TESTIMONY?**

A. Company witness Skirtich provided two revised customer cost analyses in rebuttal testimony (Columbia JES-1R, pp. 14-18).

Q. **WHAT REVISIONS DID MR. SKIRTICH MAKE TO HIS REVISED CUSTOMER COST ANALYSES?**

A. The Company revised its customer cost analysis by reflecting corrections to and revisions of the cost of service proposed by other parties and accepted by the Company. The Company has revised the allocation of costs concerning the following accounts:

Account No.	
303.30	Customer & Other-Based Software
380.00	Services
874.00	Mains & Services (Services Only)
892.00	Services
904.00	Uncollectibles-Dis Revenue
904.00	Uncollectibles-GMB/GTS Revenue
910.00	Large Customer Relations

In addition to these revision, Mr. Skirtich has agreed that "other rate base items", particularly accumulated deferred income taxes, customer advances and customer deposits, should be included in the "system charge" (Columbia St. No. 109-R, pp. 3-4).

Q. WHAT IS YOUR RESPONSE TO MR. SKIRTICH'S REVISED CUSTOMER COST ANALYSES?

A. I compiled a revised customer cost analysis based on the one revised customer cost analysis without mains provided by Mr. Skirtich. The results of my revised I&E customer cost analysis are shown on I&E Exhibit No. 3-SR, Schedule 1.

Q. WHAT ARE THE DIFFERENCES BETWEEN THE COMPANY'S REVISED CUSTOMER COST ANALYSES AND YOUR CUSTOMER COST ANALYSIS?

A. I excluded costs associated with uncollectible expense, miscellaneous expenses, other supplies, demonstration expense and advertising expense (I&E Ex.

No. 3-SR, Sch. 1, pp 5-6). Finally, I added $1,408,791 of late payment and other revenue as an offset to customer costs.

Q. WHY DID YOU EXCLUDE THE UNCOLLECTIBLE, MISCELLANEOUS, OTHER SUPPLIES, DEMONSTRATION AND ADVERTISING EXPENSES?

A. As described in my direct testimony, they are neither direct nor indirect customer costs. Therefore, pursuant to long-standing Commission practice, these costs should not be included in a correctly conducted customer cost analysis.

Q. DID THE COMPANY ADDRESS YOUR CUSTOMER COST ANALYSIS?

A. Yes. The Company believes I should have included the indirect costs the Commission allowed PPL Electric to include in its most recent case.

Q. HOW DID THE COMPANY ADDRESS YOUR CUSTOMER COST ANALYSIS?

A. The Company believes I should have included the indirect costs the Commission allowed PPL Electric to include in its most recent base rate case at Docket No. R-2012-2290597. Mr. Skirtich contends that the Commission in the recently concluded PPL Electric base rate case included indirect customer and other costs in approving PPL's customer charge levels. However, these costs that I removed were *not* included in the items claimed by PPL Electric as customer costs in that case. If Columbia is attempting to obtain Commission approval of its customer cost analysis based upon the Commission's action in the PPL Electric case, it should at least be required to conduct a similar type of customer cost analysis and not be allowed to pick and choose different costs to include or exclude.

Q. WHY DID YOU ADD REVENUE FROM LATE PAYMENT AND OTHER REVENUE AS AN OFFSET TO CUSTOMER COSTS?

A. Again, these offsets to revenue used to reduce customer costs *were* included as part of the customer cost analysis conducted by PPL Electric in Docket No. R-2012-2290597. Therefore, for the same reason I excluded uncollectibles and other costs identified above, if Columbia is going to rely on the Commission's order in the PPL Electric base rate case, it is only fair and reasonable to require the Company to include non-direct offsets if it includes other non-direct costs to be recovered in the customer charge.

Q. DOES YOUR REVISED CUSTOMER COST ANALYSIS INCLUDE ALL THE ITEMS THE COMMISSION ALLOWED PPL TO INCLUDE IN ITS MOST RECENT CASE?

A. Yes. As described above, I allowed all items claimed by the Company that the Commission allowed PPL Electric to include in its most recent case at Docket No. R-2012-2290597.

Q. DOES YOUR REVISED CUSTOMER COST ANALYSIS PRODUCE DIFFERENT RESULTS THAN THE ONE YOU PROVIDED IN YOUR DIRECT TESTIMONY?

A. Yes. Based on my customer cost analysis, I determined that the Company incurs $15.44 per month in customer costs for each RS/RDS customer, $24.03 per month $25.67 per month in customer costs for each SGS/SGDS customer, $171.94 per month in customer costs for each LGS customer, $142.53 per month in customer costs for each SDS customer, $740.20 per month in customer costs for each LDS customer, and $752.95 per month in customer costs for each MDS customer (I&E Ex. No. 3-SR, Sch. 1, p. 1, ln. 11).

Q. SHOULD THE COMMISSION CONSIDER THE RESULTS OF THE COMPANY'S CUSTOMER COST ANALYSIS THAT INCLUDES MAIN COSTS?

A. No. Mains are not customer costs. Furthermore, the equivalent asset for electric utilities would be wires and poles, which were not included in the customer cost analysis prepared by PPL Electric and approved in Docket No. R-2012-229059. Therefore, it is only fair and reasonable to conclude that gas mains are not customer costs and should not be included in the customer cost analysis, or recovered in the customer charges.

Q. BASED ON YOUR REVISED CUSTOMER COST ANALYSIS, WHAT CUSTOMER CHARGE DO YOU RECOMMEND FOR THE RS/RDS CLASS?

A. I recommend a **$15.44** per month customer charge for the RS/RDS customers, which is a reduction from the $16.53 charge I recommended in my direct testimony. If the Commission accepts Columbia's contention that the Company should be allowed to construct a customer charge analysis in the same fashion as PPL Electric, then the Commission should adopt my revised recommendation, which includes the items claimed by the Company and approved in the PPL base rate case.

Q. WHAT DID MR. KEMPIC CLAIM WITH RESPECT TO THE INCLUSION OF BOTH A CUSTOMER CHARGE AND A USAGE CHARGE ON RESIDENTIAL CUSTOMER BILLS?

A. Company witness Kempic claimed that residential customer bills would be less confusing if the distribution usage charges were eliminated and residential customers paid a flat monthly charge (Columbia St. No. 1. p. 24).

Q. WHAT WAS YOUR POSITION REGARDING THE COMPANY'S CLAIMS CONCERNING THE ALLEGED CONFUSION OF RESIDENTIAL CUSTOMERS?

A. I stated that customers should receive a lower distribution bill if they lower their usage, something that would not occur if there is only a fixed monthly customer charge with no distribution usage charge. I also stated that it would be just as simple to eliminate the customer charge as it would be to eliminate the usage charges (I&E St. No. 3, p. 45).

Q. WHAT WAS THE COMPANY'S RESPONSE TO YOUR POSITION?

A. Ms. Strauss acknowledged this section of my testimony, but did not address the customer confusion issue. Therefore, the Company provided no rebuttal testimony to address my argument that it would be simpler and less confusing to a customer if the monthly charge were eliminated and the Company's only distribution charge was based upon usage. The Company did address a rate structure that includes both a customer charge and distribution usage rates which I have accepted (Columbia St. No. 115-R, pp. 8).

COST OF SERVICE

Q. HOW DID THE COMPANY ALLOCATE THE PROPOSED REVENUE INCREASE?

A. As stated in my direct testimony, the Company used the results of both the design day as well as the peak & average methodologies when designing the proposed revenue requirement and rates (I&E St. No. 3, p. 21).

Q. DID YOU RECOMMEND A CHANGE IN WHAT COST OF SERVICE STUDY SHOULD BE USED AS A GUIDE IN ALLOCATING THE FINAL REVENUE INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

A. Yes. In my direct testimony, I recommended that the peak and average methodology be used to allocate the cost of distribution plant and related expenses (I&E St. No. 3, p. 23).

Q. WHAT WAS THE RESPONSE FROM THE COMPANY AND OTHER PARTIES TO YOUR RECOMMENDATION?

A. The Company disagrees with my recommendation to allocate the cost of mains to the various classes based on the peak and average method and continues to assert that a mix of cost of service studies should be used (Columbia St. No. 109-R, p. 17). OSBA witness Knecht claims it is unclear why I did not rely on the 1994 National Fuel Gas Distribution Company base rate proceeding with respect to the issue of splitting mains into separate Small Diameter Low Pressure ("SDLP") and Large Diameter High Pressure ("LDHP") categories (OSBA St. No. 2, pp. 2-4).

Q. WHAT RATIONALE DID THE COMPANY PROVIDE FOR NOT AGREEING WITH YOUR RECOMMENDATION?

A. The Company does not concur that a single cost study should form the basis of a rate design (Columbia St. No. 112-R, p. 44).

Q. IS THE COMPANY'S STATED BELIEF A PROPER BASIS FOR ALLOCATING THE COST OF MAINS TO THE VARIOUS CUSTOMER CLASSES?

A. No. As stated in my direct testimony, the Company has recognized that the Commission generally considers the peak and average method as the most useful guide in allocating revenue requirement (I&E St. No. 3, p. 23). There is simply no demonstrated reason here to consider a methodology that the Commission has previously rejected.

Q. ADDRESSING THE CONCERNS OF THE OSBA WITH REGARD TO THE NATIONAL FUEL GAS DISTRIBUTION BASE RATE PROCEEDING, DID YOU OBJECT TO THE COMPANY CLASSIFYING MAINS AS EITHER SDLP OR LDHP?

A. No. I considered but did not object to this classification.

SCALEBACK OF RATES

Q. WHAT WAS YOUR PROPOSED SCALEBACK OF RATES IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE REQUESTED BY THE COMPANY?

A. I recommended the first $200,000 be assigned to reduce the proposed SDS rates, and the next $6,000,000 be used to reduce the proposed RS/RDS rates (I&E St. No. 3, p. 27). Any further reduction should be proportional to the percentage increases shown on I&E Exhibit No. 3, Schedule 8, page 3, line 20 (I&E St. No. 3, p. 29).

Q. WHAT WAS THE COMPANY'S RESPONSE TO YOUR SCALEBACK RECOMMENDATION?

A. Company witness Strauss agreed with my scaleback recommendation. (Columbia St. No. 115-R, p. 2).

Q. WHAT OTHER PARTIES ADDRESSED YOUR SCALEBACK RECOMMENDATION?

A. OSBA Witness Knecht addressed and disagrees with my scaleback recommendation (OSBA St. No. 2, p. 10).

Q. WHY DOES THE OSBA WITNESS KNECHT DISAGREE WITH YOUR RECOMMENDATION?

A. OSBA witness Knecht's disagreement is based on my reliance on the results of the Company's peak and average cost of service study, and on the manner in which mains are classified in that study (OSBA St. No. 2, p. 10).

Q. WHAT IS YOUR RESPONSE TO THESE CRITICISMS OF YOUR USE OF THE PEAK AND AVERAGE COST OF SERVICE STUDY TO DETERMINE A PROPER SCALEBACK OF RATES?

A. I continue to support use of the peak and average study. As stated in my direct testimony, the Company has recognized that the Commission generally considers the peak and average method as the most useful guide in allocating revenue requirement (I&E St. No. 3, p. 23). As a result, it should be used to allocate a scaleback of rates if the Commission grants less than the full increase in rates. While OSBA witness Knecht may disagree with the peak and average methodology, his position lacks Commission support.

<u>RESIDENTIAL RATE DESIGN – REVENUE DECOUPLING</u>

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING THE COMPANY'S THREE DIFFERENT REVENUE DECOUPLING PROPOSALS, THE RNA, WNA, AND LDC.

A. I did not agree with the Company's assertions that additional rate design modifications were necessary, particularly in light of the provisions afforded in Act 11 subsequent to Columbia's last base rate case. However, I offered the opinion that if the Commission were inclined to adopt a revised rate design, I supported the Company's proposed Revenue Normalization Adjustment.

Q. HAS THE COMPANY RESPONDED TO YOUR RECOMMENDATION?

A. Yes. Columbia witness Strauss states that the Company does not oppose my residential rate structure "with the inclusion of the Revenue Normalization Adjustment" (Columbia Statement No. 115-R, p. 5). However, Ms. Strauss then goes on to describe changes to my proposed rate structure that are inconsistent with my recommendation. For example, while the Company supports eliminating the 2.1 Dth per month allowance in the fixed monthly charge, she claims that the fixed charge must increase – despite the removal of the usage component – unless the RNA is approved (Columbia Statement No. 115-R, p. 6). This is not my recommendation.

Q. HOW DOES MS. STRAUSS ADDRESS YOUR CONCERNS THAT IMPLEMENTATION OF THE RNA GREATLY REDUCES CUSTOMERS' ABILITIES TO BENEFIT FROM THEIR CONSERVATION EFFORTS?

A. Ms. Strauss claims that under the RNA residential customers will still be able to "enjoy the benefits of their conservations efforts . . . primarily the savings experienced from the reduced consumption of natural gas" (Columbia Statement No. 115-R, p. 9). While it is a simple fact that the less gas a customer uses, the less gas the customer has to pay for, that is no different than any other purchase customers may make. The fewer shoes I buy, the fewer shoes I have to pay for. However, purchasing natural gas distribution service is not the equivalent of purchasing a pair of shoes, and while customers can forego a few extra pairs of shoes, natural gas service is a necessity. Therefore, any hindrance to a customer's ability to receive the full benefit from conserving is a concern not to be treated lightly.

Q. DO YOU HAVE ANY FURTHER RESPONSE TO MS. STRAUSS' REBUTTAL TESTIMONY REGARDING THE RNA?

A. Yes. Mr. Strauss minimizes the benefits afforded the Company through enactment of Act 11 by comparing the Company's ability to recover revenues without the RNA to a landlord with a tenant who essentially has no requirement to commit to a lease and only pay for the days or months the property is used (Columbia Statement No. 115-R, p. 7). That is a faulty comparison. Customers cannot pick and choose the days that will use gas and only pay the Company at those times for several reasons. First, the Company collects all direct customer costs, and some indirect customer costs, through the fixed monthly customer charge regardless whether or not a customer actually uses any gas. Second, the Company imposes disconnection and reconnection fees that inhibit customers from leaving the system, and thereby avoiding all payments to the Company. So under traditional ratemaking the Company is not in the position of the landlord in Ms. Strauss' analogy.

Q. DO YOU WISH TO REVISE YOUR REVENUE DECOUPLING RECOMMENDATION?

A. Yes. I no longer believe that approval of the RNA as proposed by the Company is the best recommendation to make to the Commission in this proceeding. I now believe that a Weather Normalization Adjustment (WNA), which only allows reconciliation to account for deviations in weather – a factor wholly outside the Company's control established as a pilot program – is a more appropriate mechanism.

Q. WHY DO YOU WISH TO WITHDRAW YOUR RECOMMENDATION TO IMPLEMENT THE RNA?

A. I agree with Ms. Strauss' characterization of the RNA as ensuring that the Company collects no more or less than "a fair baseline revenue requirement set during a base rate proceeding" (Columbia Statement No. 115-R, p. 7). While I originally recommended that if the Commission were inclined to approve a revenue decoupling mechanism it should approve the RNA as proposed by the Company, in light of the various positions of the parties exposed in testimony on the subject, I believe that approval of a more limited decoupling mechanism, and for a limited period of time so that the Commission may gather data and evaluate the operations of the mechanism, would be a better resolution of this issue. Revenue decoupling is a significant deviation from traditional ratemaking and should be approached cautiously. Rather than reconciling revenues through the RNA in a way that almost guarantees the Company recovery of an authorized return, a notion that is not supported in traditional ratemaking, I believe proceeding more cautiously under a circumscribed pilot WNA is a better option.

Q. HOW SHOULD THE WNA BE STRUCTURED?

A. I believe the program should be initiated as a pilot with a defined term over which the Company can gather data and evaluate the functioning of the program, and provide that information to the Commission in its next base rate case. Implementing it as a pilot also helps ensure that the entire energy industry does not file for identical treatment until the Commission is prepared to evaluate the ramifications of decoupling and determine whether it should be continued. Finally, the WNA that is in effect for PGW contains a dead band of 1%, which requires a deviation in weather greater than 1% above and 1% below normal before there is any reconciliation. Since PGW is a cash flow company, a very low dead band may have been more appropriate. However, I believe a dead band of perhaps 3% or 4% would be better for Columbia.

<u>TARIFF LANGUAGE – SYSTEM CHARGE</u>

Q. WHAT WAS YOUR RECOMMENDATION REGARDING THE COMPANY PROPOSAL TO CHANGE THE DEFINITION OF CUSTOMER CHARGE IN THE PROPOSED TARIFF?

A. I recommended that the Company not be permitted to change the name "customer charge" to a "system charge" (I&E St. No. 3, p. 52).

Q. WHAT WAS THE BASIS FOR YOUR RECOMMENDATION?

A. As described in my direct testimony, the concept of a customer charge and its manner of calculation enjoys long-standing precedent before this Commission as a reasonable part of the ratc structure policy and thc overall ratemaking process. This policy should not change simply because of the way Columbia desires to recover its costs (I&E St. No. 3, p. 52).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION?

A. Yes. Company witness Bardes Hasson continues to recommend that all references to "customer charge" be changed to "system charge" because she believes the term is more accurate. To support this claim, Ms. Bardes Hasson cites to a Commission brochure (Columbia St. No. 116-R, p 2). The Company also claims that the term "system charge" was conceived independent of any rate design proposal. The Company also supports its contention by citing Section 62.74 of the Public Utility code which refers to the monthly charge as a "customer charge" or "basic charge"(Columbia St. No. 116-R, p.3).

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S ARGUMENT THAT A DEFINITION IN A COMMISSION BROCHURE SUPPORTS ITS POSITION?

A. A definition in a Commission brochure is not persuasive authority for such a change like a final determination of an issue in a rate case would be. Even assuming for argument sake it might be, I do not agree that the "brochure" supports the Company's contention, since the brochure calls the monthly charge a "customer charge" and not a "system charge," as shown on the page of the Commission brochure that the Company refers to (I&E Exhibit No. 3-SR, Schedule 2). Further, I believe the term "service lines" described in the brochure refers to the service line from the main to the customer and not the distribution mains.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S ARGUMENT THAT THE TERM "BASIC CHARGE" USED TO DESCRIBE THE MONTHLY CHARGE IN THE ELECTRIC INDUSTRY SUPPORTS ITS PROPOSED TARIFF CHANGE TO "SYSTEM CHARGE"?

A. The term "system charge" is not used in the electric industry in Pennsylvania.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S CLAIM THAT IT WOULD HAVE PROPOSED TO CHANGE THE NAME OF ITS CUSTOMER CHARGE TO A "SYSTEM CHARGE" INDEPENDENT OF ITS RATE DESIGN PROPOSAL?

A. I have no way of disputing the Company's contention that it would have proposed to change all references to "customer charge" regardless of its other rate structure proposals. I can say that changing the name to "system charge" has the explicit effect of supporting the Company's desire to collect all its costs through a fixed or fully reconcilable monthly charge regardless of usage. For that reason, I suspect, though I obviously cannot prove, the Company's motivation. Moreover, I also believe that if the Commission allows the long-standing term to be changed, it could enhance the Company's unsupported efforts to include even more indirect costs in the monthly customer charge in future cases. Finally, until the Commission makes the substantive change from the traditional rate design that includes both a customer charge and a usage charge, there should be no change to the name of the charge. Therefore, the Company's proposal to change the term "customer charge" to "system charge" should be denied.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Exhibit No. 3-SR
Witness: Jeremy B. Hubert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Exhibit to Accompany

the

Surrebuttal Testimony

of

Jeremy B. Hubert

Bureau of Investigation and Enforcement

Concerning:

Test Year
Rate Base
Annual Depreciation Expense
Cost of Service
Scaleback
Customer Cost Analysis
Residential Rate Design
Tariff Language
Forfeited Discounts

Q-13-13
Hbg QR

Columbia Gas of Pennsylvania, Inc.
R-2012-2321748

BI&E Total Customer Costs

	Cost Function	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	O and M Expense	$25,931,345	$4,326,755	$72,990	$444,087	$661,886	$65,238
2	Depreciation	$13,623,205	$2,081,384	$33,934	$108,375	$63,943	$6,570
3	Net Salvage Amortized	$1,397,989	$208,547	$4,650	$19,395	$29,491	$465
4	Subtotal Customer Costs	$40,952,539	$6,616,686	$111,574	$571,857	$755,320	$72,273
5	Rate Base	$246,568,212	$32,647,013	$409,152	$1,220,458	$546,375	$81,451
6	Return	$21,007,612	$2,781,525	$34,860	$103,983	$46,551	$6,940
7	Taxes	$10,292,795	$1,362,824	$17,080	$50,947	$22,808	$3,400
8	Taxes and Return	$31,300,406	$4,144,349	$51,939	$154,930	$69,359	$10,340
9	Late Payment	$766,231	$156,633	$944	$9,661	$9,614	$1,284
10	Other Revenue	$423,090	$40,670	$87	$465	$102	$10
11	Total Other	$1,189,321	$197,303	$1,031	$10,126	$9,716	$1,294
12	Total Direct Customer Costs	$71,063,624	$10,563,732	$162,482	$716,661	$814,963	$81,319
13	Average Annual Cust. Bills	4,603,511	439,658	945	5,028	1,101	108
14	**Cost per Bill**	**$15.44**	**$24.03**	**$171.94**	**$142.53**	**$740.20**	**$752.95**

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014
Customer Costs - Rate Base

Company

	Acct. No.	Gross Plant	Total A	RS/RDS B	SGS/SGDS C	LGS D	SDS E	LDS F	MDS G
1	303.30	Customer & Other-Based Software	$12,725,296	$10,713,300	$1,598,170	$35,631	$148,631	$226,001	$3,563
2	380.00	Services	$370,945,092	$340,431,150	$29,838,823	$148,378	$337,560	$189,182	$0
3	380.00	Direct - Services	$37,326	$0	$0	$0	$0	$0	$37,326
4	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$34,301,875	$25,721,261	$8,124,056	$94,673	$278,874	$78,551	$4,459
6	381.10	Automatic Meter Reading	$20,548,041	$15,407,948	$4,866,598	$56,713	$167,056	$47,055	$2,671
7	382.00	Meter Installations	$35,468,816	$26,596,292	$8,400,434	$97,894	$288,361	$81,224	$4,611
8	383.00	House Regulators	$10,741,363	$8,054,411	$2,543,984	$29,646	$87,327	$24,598	$1,396
9	384.00	House Reg. Installations	$3,864,772	$2,897,999	$915,333	$10,667	$31,421	$8,050	$502
10	385.00	Ind. M&R Equipment	$5,355,556	$0	$3,583,135	$317,263	$1,044,869	$410,289	$0
11	385.00	Direct - Ind. M&R Equipment	$122,846	$0	$0	$0	$0	$0	$122,846
12	385.10	Ind. M&R Equipment - LG Volume	$1,356,628	$0	$907,652	$80,367	$264,678	$103,931	$0
13		Total Gross Plant	$495,467,612	$429,822,361	$60,778,185	$871,231	$2,648,777	$1,169,682	$177,376
		Depreciation Reserve							
			Total	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
14	303.30	Customer & Other-Based Software	$4,671,863	$3,933,196	$586,739	$13,081	$54,567	$82,972	$1,308
15	380.00	Services	$100,860,024	$92,563,279	$8,113,180	$40,344	$91,783	$51,439	$0
16	380.00	Direct - Services	$21,692	$0	$0	$0	$0	$0	$21,692
17	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
18	381.00	Meters	$14,998,136	$11,246,352	$3,552,159	$41,395	$121,935	$34,346	$1,950
19	381.10	Automatic Meter Reading	$4,440,562	$3,329,755	$1,051,703	$12,256	$36,102	$10,169	$577
20	382.00	Meter Installations	$10,435,222	$7,824,851	$2,471,478	$28,801	$84,838	$23,897	$1,357
21	383.00	House Regulators	$2,868,259	$2,150,764	$679,318	$7,916	$23,319	$6,568	$373
22	384.00	House Reg. Installations	$2,788,621	$2,091,048	$660,457	$7,697	$22,672	$6,386	$363
23	385.00	Ind. M&R Equipment	$3,181,978	$0	$2,128,902	$188,500	$620,504	$243,771	$0
24	385.00	Direct - Ind. M&R Equipment	$44,342	$0	$0	$0	$0	$0	$44,342
		Total 385	$3,226,320						
25	385.10	Ind M&R Equipment - LG Volume	$73,950	$0	$49,476	$4,381	$14,428	$5,665	$0
26		Ttoal Depreciation Reserve	$144,384,649	$123,139,245	$19,293,412	$344,371	$1,070,447	$465,213	$71,961
27	154.00	Customer Based Materials and Supplies	$224,476	$194,885	$27,518	$389	$1,163	$439	$81
28	190.00	Customer Based Deferred Income Taxes	($67,089,852)	($58,201,015)	($8,229,800)	($117,971)	($358,663)	($158,383)	($24,018)
29	235.00	Customer Deposits	($2,671,287)	($2,044,844)	($626,444)	$0	$0	$0	$0
30	252.00	Customer Advances	($73,636)	($63,931)	($9,027)	($127) #	($381)	($144)	($27)
31		Total Customer Related	($69,610,299)	($60,114,905)	($8,837,753)	($117,709) #	($357,881)	($158,088)	($23,964)
32		Total Cust.-Based Rate Base	$281,472,664	$246,569,211	$32,647,020	$409,151	$1,220,449	$546,381	$81,451

BI&E

	Acct. No.	Gross Plant	Total H	RS/RDS I	SGS/SGDS J	LGS K	SDS L	LDS M	MDS N
1	303.30	Customer & Other-Based Software	$12,725,296	$10,713,304	$1,598,169	$35,629	$148,631	$225,999	$3,563
2	380.00	Services	$370,945,092	$340,431,150	$29,838,821	$148,378	$337,561	$189,183	$0
3	380.00	Direct - Services	$37,326	$0	$0	$0	$0	$0	$37,326
4	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$34,301,875	$25,721,260	$8,124,057	$94,674	$278,875	$78,552	$4,460
6	381.10	Automatic Meter Reading	$20,548,041	$15,407,947	$4,866,599	$56,713	$167,057	$47,056	$2,670
7	382.00	Meter Installations	$35,468,816	$26,596,291	$8,400,434	$97,893	$288,360	$81,225	$4,612
8	383.00	House Regulators	$10,741,363	$8,054,411	$2,543,983	$29,645	$87,327	$24,597	$1,397
9	384.00	House Reg. Installations	$3,864,772	$2,898,000	$915,333	$10,667	$31,421	$8,850	$503
10	385.00	Ind. M&R Equipment	$5,355,556	$0	$3,583,134	$317,263	$1,044,869	$410,289	$0
11	385.00	Direct - Ind. M&R Equipment	$122,846	$0	$0	$0	$0	$0	$122,846
12	385.10	Ind. M&R Equipment - LG Volume	$1,356,628	$0	$907,647	$80,370	$264,685	$103,926	$0
13		Total Gross Plant	$495,467,611	$429,822,363	$60,778,178	$871,232	$2,648,787	$1,169,676	$177,377
		Depreciation Reserve							
			Total	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
14	303.30	Customer & Other-Based Software	$4,671,863	$3,933,197	$586,739	$13,081	$54,567	$82,972	$1,308
15	380.00	Services	$100,860,024	$92,563,230	$8,113,180	$40,344	$91,783	$51,439	$0
16	380.00	Direct - Services	$21,692	$0	$0	$0	$0	$0	$21,692
17	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
18	381.00	Meters	$14,998,136	$11,246,351	$3,552,159	$41,395	$121,935	$34,346	$1,950
19	381.10	Automatic Meter Reading	$4,440,562	$3,329,755	$1,051,703	$12,256	$36,102	$10,169	$577
20	382.00	Meter Installations	$10,435,222	$7,824,851	$2,471,478	$28,801	$84,838	$23,397	$1,357
21	383.00	House Regulators	$2,868,259	$2,150,765	$679,318	$7,916	$23,319	$6,568	$373
22	384.00	House Reg. Installations	$2,788,621	$2,091,047	$660,457	$7,697	$22,672	$6,386	$363
23	385.00	Ind. M&R Equipment	$3,181,978	$0	$2,128,903	$188,500	$620,804	$243,771	$0
24	385.00	Direct - Ind. M&R Equipment	$44,342	$0	$0	$0	$0	$0	$44,342
		Total 385	$3,226,320						
25	385.10	Ind M&R Equipment - LG Volume	$73,950	$0	$49,476	$4,381	$14,428	$5,665	$0
26		Ttoal Depreciation Reserve	$144,384,649	$123,139,265	$19,293,412	$344,371	$1,070,448	$465,213	$71,962
27	154.00	Customer Based Materials and Supplies	$224,476	$194,885	$27,518	$389	$1,163	$439	$81
28	190.00	Customer Based Deferred Income Taxes	($67,089,552)	($58,201,015)	($8,229,800)	($117,971)	($358,663)	($158,383)	($24,018)
29	235.00	Customer Deposits	($2,671,287)	($2,044,844)	($626,444)	$0	$0	$0	$0
30	252.00	Customer Advances	($73,636)	($63,931)	($9,027)	($127)	($381)	($144)	($27)
31		Total Customer Related	($69,610,299)	($60,114,905)	($8,837,753)	($117,709)	($357,881)	($158,088)	($23,964)
32		Total Cust.-Based Rate Base	$281,472,663	$246,568,212	$32,647,013	$409,152	$1,220,458	$546,375	$81,451

I&E Exhibit No. 3-SR
Schecule 1
page 2 of 6

Columbia Gas of Pennsylvania, Inc.
R-2012-2321748

	Item		COMPANY						BI&E					
	Item		RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
1	Total Rate Base		$246,568,211	$32,647,020	$409,151	$1,220,449	$546,381	$81,451	$246,568,212	$32,647,013	$409,152	$1,220,458	$546,375	$81,451
2	Rate of Return	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%	8.52%
3	Total Income	$23,981,471	$21,007,612	$2,781,526	$34,860	$103,982	$46,552	$6,940	$21,007,612	$2,781,525	$34,860	$103,983	$46,551	$6,940
4		49.00%												
5	Income Taxes	$11,749,853	$10,292,795	$1,362,824	$17,080	$50,947	$22,808	$3,400	$10,292,795	$1,362,824	$17,080	$50,947	$22,808	$3,400

I&E Exhibit No. 3-SR
Schedule 1
page 3 of 6

Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 8/30/2014
Customer Costs - Depreciation

Company

	Acct. No.	Depreciation Expense	Total A	RS/RDS B	SGS/SGDS C	LGS D	SDS E	LDS F	MDS G
1	303.30	Customer & Other-Based Software	$1,756,934	$1,479,146	$220,653	$4,919	$20,521	$31,203	$492
2	380.00	Services	$10,226,750	$9,385,499	$822,640	$4,091	$9,306	$5,216	$0
3	380.00	Direct - Services	$956	$0	$0	$0	$0	$0	$956
4	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$835,931	$626,823	$197,982	$2,307	$6,796	$1,914	$109
6	381.10	Automatic Meter Reading	$1,778,260	$1,333,428	$421,163	$4,908	$14,457	$4,072	$231
7	382.00	Meter Installations	$707,167	$530,269	$167,485	$1,952	$5,749	$1,619	$92
8	383.00	House Regulators	$284,993	$213,702	$67,498	$787	$2,317	$653	$37
9	384.00	House Reg. Installations	$72,465	$54,338	$17,163	$200	$589	$166	$9
10	385.00	Ind. M&R Equipment	$245,096	$0	$163,982	$14,520	$47,818	$18,777	$0
11	385.00	Direct - Ind. M&R Equipment	$4,644	$0	$0	$0	$0	$0	$4,644
12	385.10	Ind. M&R Equipment - LG Volume	$4,212	$0	$2,818	$250	$822	$323	$0
13		Total Depreciation Expense	$15,917,408	$13,623,205	$2,081,384	$33,934	$108,375	$63,943	$6,570
14		Total Net Salvage Amortized	$1,660,536	$1,397,989	$208,547	$4,650	$19,395	$29,491	$465
14		Total Net Salvage Amortized	$17,577,944	$15,021,194	$2,289,931	$38,584	$127,770	$93,434	$7,035

BI&E

	Acct. No.	Depreciation Expense	Total H	RS/RDS I	SGS/SGDS J	LGS K	SDS L	LDS M	MDS N
1	303.30	Customer & Other-Based Software	$1,756,934	$1,479,146	$220,653	$4,919	$20,521	$31,203	$492
2	380.00	Services	$10,226,750	$9,385,499	$822,640	$4,091	$9,306	$5,216	$0
3	380.00	Direct - Services	$956	$0	$0	$0	$0	$0	$956
4	380.12	CSL Replacement	$0	$0	$0	$0	$0	$0	$0
5	381.00	Meters	$835,931	$626,823	$197,982	$2,307	$6,796	$1,914	$109
6	381.10	Automatic Meter Reading	$1,778,260	$1,333,428	$421,163	$4,908	$14,457	$4,072	$231
7	382.00	Meter Installations	$707,167	$530,269	$167,485	$1,952	$5,749	$1,619	$92
8	383.00	House Regulators	$284,993	$213,702	$67,498	$787	$2,317	$653	$37
9	384.00	House Reg. Installations	$72,465	$54,338	$17,163	$200	$589	$166	$9
10	385.00	Ind. M&R Equipment	$245,096	$0	$163,982	$14,520	$47,818	$18,777	$0
11	385.00	Direct - Ind. M&R Equipment	$4,644	$0	$0	$0	$0	$0	$4,644
12	385.10	Ind. M&R Equipment - LG Volume	$4,212	$0	$2,818	$250	$822	$323	$0
13		Total Depreciation Expense	$15,917,408	$13,623,205	$2,081,384	$33,934	$108,375	$63,943	$6,570
14		Total Net Salvage Amortized	$1,660,536	$1,397,989	$208,547	$4,650	$19,395	$29,491	$465
14		Total Net Salvage Amortized	$17,577,944	$15,021,194	$2,289,931	$38,584	$127,770	$93,434	$7,035

I&E Exhibit No. 3-SR
Schedule 1
page 4 of 6

Columbia Gas of Pennsylvania, Inc.

Docket No. R-2012-2321748

Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014

Customer Costs - Expenses

Company

	Acct. No.	Customer Costs - Details	Total A	RS/RDS B	SGS/SGDS C	LGS D	SDS E	LDS F	MDS G
		Distribution							
1	874.00	Mains & Services (Services Only)	$3,137,844	$2,879,726	$252,408	$1,255	$2,855	$1,600	$0
2	876.00	M & R - Industrial	$245,982	$0	$164,574	$14,572	$47,991	$18,845	$0
3	878.00	Meters & House Regulators	$2,455,745	$1,841,440	$581,619	$6,778	$19,965	$5,624	$319
4	879.00	Customer Installations	$4,813,089	$3,609,095	$1,139,932	$13,284	$39,130	$11,022	$626
5	890.00	M &R - Industrial	$127,109	$0	$85,042	$7,530	$24,799	$9,738	$0
6	892.00	Services	$2,984,104	$2,738,631	$240,041	$1,194	$2,716	$1,522	$0
7	893.00	Meters & House Regulators	$286,063	$214,504	$67,751	$790	$2,326	$655	$37
8		**Total Distribution**	$14,049,936	$11,283,396	$2,531,367	$45,403	$139,782	$49,006	$982
		Customer Accounts							
9	901.00	Supervision	$0	$0	$0	$0	0	$0	$0
10	902.00	Meter Reading	$2,126,148	$1,936,920	$186,187	$404	$2,126	$468	$43
11	903.00	Collecting - Delinquent Accts	$1,072,108	$976,690	$93,885	$204	$1,072	$236	$21
12	903.00	Collecting - Current Accts	$7,960	$7,251	$697	$2	$8	$2	$0
13	903.00	Billing & Accounting	$5,797,612	$5,281,623	$507,697	$1,102	$5,798	$1,275	$116
14	903.00	Rendering Bills	$2,484,721	$2,263,580	$217,587	$472	$2,485	$547	$50
15	904.00	Uncollectibles - Dis Revenue	$3,037,943	$2,601,391	$415,165	$3,949	$7,139	$9,509	$790
16	904.00	Uncollectibles - GMB/GTS Revenue	$38,961	$33,362	$5,324	$51	$92	$122	$10
17	905.00	Miscellaneous	$17,447	$15,895	$1,528	$3	$17	$4	$0
18	921.00	Office Supplies & Expenses	$4,212	$3,837	$369	$1	$4	$1	$0
19		**Total Customer Accounts**	$14,587,111	$13,120,549	$1,428,439	$6,188	$18,741	$12,164	$1,030
		Cust. Service & Information							
20	907.00	Supervision	$0	$0	$0	$0	$0	$0	$0
21	908.00	Customer Assistance	$613,464	$558,877	$53,721	$117	$614	$135	$0
22	909.00	Informational & Instructional Expens	$38,184	$34,786	$3,344	$7	$38	$8	$1
23	910.00	Miscellaneous	$600,791	$547,321	$52,611	$114	$601	$132	$12
24	910.00	Large Customer Relations	$986,405	$0	$113,091	$12,567	$245,033	$552,890	$62,824
25	921.00	Office Supplies & Expenses	$9,085	$8,276	$796	$2	$9	$2	$0
26	931.00	Rents - General	$140	$128	$12	$0	$0	$0	$0
27		**Total Cust. Service & Information**	$2,248,069	$1,149,388	$223,575	$12,807	$246,295	$553,167	$62,837
		Sales							
28	912.00	Demonstration	$650,917	$592,985	$57,001	$124	$651	$143	$13
29	913.00	Advertising	$128,866	$117,396	$11,285	$25	$129	$28	$3
30		**Total Sales**	$779,783	$710,381	$68,286	$149	$780	$171	$16
31		**Customer Related Benefits**	$3,715,748	$3,032,497	$565,760	$12,596	$46,521	$57,185	$1,189
32		**Total Customer Related O&M**	$35,380,646	$29,296,212	$4,817,426	$77,140	$452,120	$671,694	$66,054

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Schedule 1
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Columbia Gas of Pennsylvania, Inc.
Docket No. R-2012-2321748
Cost of Service Study - Fully Forecasted Rate Year Ended 6/30/2014
Customer Costs - Expenses

			BI&E Adjustment						BI&E					
	Acct No.	Customer Costs - Details	RS/RDS H	SGS/SGDS I	LGS J	SDS K	LDS L	MDS M	RS/RDS N	SGS/SGDS O	LGS P	SDS Q	LDS R	MDS S
		Distribution												
1	874.00	Mains & Services (Services Only)	$0	$0	$0	$0	$0	$0	$2,879,726	$252,408	$1,255	$2,855	$1,600	$0
2	876.00	M & R - Industrial	$0	$0	$0	$0	$0	$0	$0	$164,574	$14,572	$47,991	$18,845	$0
3	878.00	Meters & House Regulators	$0	$0	$0	$0	$0	$0	$1,841,440	$581,619	$6,778	$19,965	$5,624	$319
4	879.00	Customer Installations	$0	$0	$0	$0	$0	$0	$3,609,095	$1,139,932	$13,284	$39,130	$11,022	$626
5	890.00	M &R - Industrial	$0	$0	$0	$0	$0	$0	$0	$85,042	$7,530	$24,759	$9,738	$0
6	892.00	Services	$0	$0	$0	$0	$0	$0	$2,738,631	$240,041	$1,194	$2,716	$1,522	$0
7	893.00	Meters & House Regulators	$0	$0	$0	$0	$0	$0	$214,504	$67,751	$790	$2,326	$655	$37
8		**Total Distribution**	$0	$0	$0	$0	$0	$0	$11,283,396	$2,531,367	$45,403	$139,782	$49,006	$982
		Customer Accounts												
9	901.00	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	902.00	Meter Reading	$0	$0	$0	$0	$0	$0	$1,936,920	$186,187	$404	$2,126	$458	$43
11	903.00	Collecting - Delinquent Accts	$0	$0	$0	$0	$0	$0	$976,690	$93,885	$204	$1,072	$236	$21
12	903.00	Collecting - Current Accts	$0	$0	$0	$0	$0	$0	$7,251	$697	$2	$8	$2	$0
13	903.00	Billing & Accounting	$0	$0	$0	$0	$0	$0	$5,281,623	$507,697	$1,102	$5,798	$1,275	$116
14	903.00	Rendering Bills	$0	$0	$0	$0	$0	$0	$2,263,580	$217,587	$472	$2,485	$547	$50
15	904.00	Uncollectibles - Dis Revenue	($2,601,391)	($415,165)	($3,949)	($7,139)	($9,509)	($790)	$0	$0	$0	$0	$0	$0
16	904.00	Uncollectibles - GMB/GTS Revenue	($33,362)	($5,324)	($51)	($92)	($122)	($10)	$0	$0	$0	$0	$0	$0
17	905.00	Miscellaneous	($15,895)	($1,528)	($3)	($17)	($4)	$0	$0	$0	$0	$0	$0	$0
18	921.00	Office Supplies & Expenses	($3,837)	($369)	($1)	($4)	($1)	$0	$0	$0	$0	$0	$0	$0
19		**Total Customer Accounts**	($2,654,485)	($422,386)	($4,004)	($7,252)	($9,636)	($800)	$10,466,064	$1,006,053	$2,184	$11,489	$2,528	$230
		Cust. Service & Information												
20	907.00	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	908.00	Customer Assistance	$0	$0	$0	$0	$0	$0	$558,877	$53,721	$117	$614	$135	$0
22	909.00	Informational & Instructional Expenses	$0	$0	$0	$0	$0	$0	$34,786	$3,344	$7	$38	$8	$1
23	910.00	Miscellaneous	$0	$0	$0	$0	$0	$0	$547,321	$52,611	$114	$601	$132	$12
24	910.00	Large Customer Relations	$0	$0	$0	$0	$0	$0	$0	$113,091	$12,567	$245,033	$552,890	$62,824
25	921.00	Office Supplies & Expenses	$0	$0	$0	$0	$0	$0	$8,276	$796	$2	$9	$2	$0
26	931.00	Rents - General	$0	$0	$0	$0	$0	$0	$128	$12	$0	$0	$0	$0
27		**Total Cust. Service & Information**	$0	$0	$0	$0	$0	$0	$1,149,388	$223,575	$12,807	$246,295	$553,167	$62,837
		Sales												
28	912.00	Demonstration	($592,985)	($57,001)	($124)	($651)	($143)	($13)	$0	$0	$0	$0	$0	$0
29	913.00	Advertising	($117,396)	($11,285)	($25)	($129)	($28)	($3)	$0	$0	$0	$0	$0	$0
30		**Total Sales**	($710,381)	($68,286)	($149)	($780)	($171)	($16)	$0	$0	$0	$0	$0	$0
31		**Customer Related Benefits**	$0	$0	$0	$0	$0	$0	$3,032,497	$565,760	$12,596	$45,521	$57,185	$1,189
32		**Total Customer Related O&M**	($3,364,866)	($490,672)	($4,153)	($8,032)	($9,807)	($816)	$25,931,345	$4,326,755	$72,990	$444,087	$661,886	$65,238

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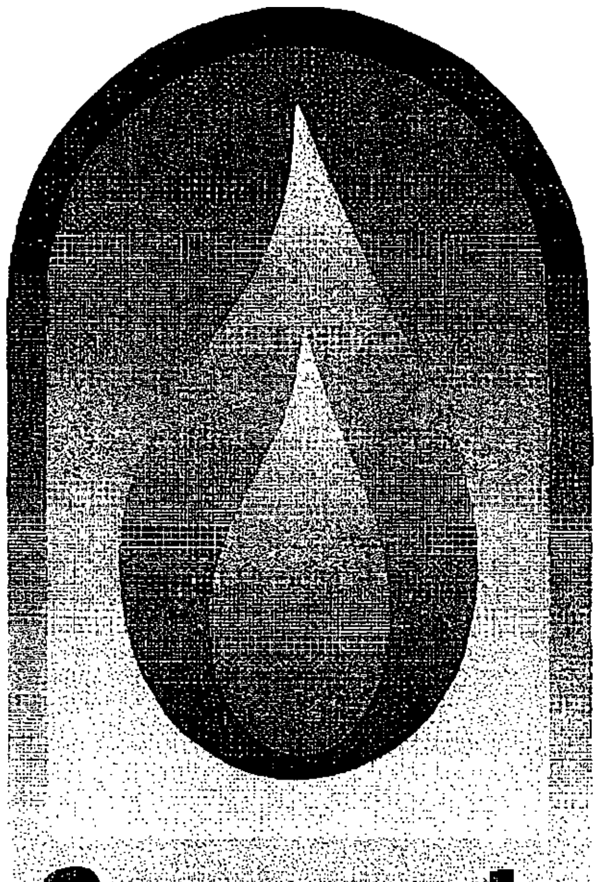

Consumer's Dictionary for Natural Gas Competition

Chapter 56 - The PUC regulations that govern metering, billing and collections for residential gas and electricity service.

City Gate - The point where interstate pipelines deliver gas into NGDC facilities.

Commodity - Natural gas sold either by volume or heating value.

Commodity Charges - The charges for basic gas supply service which is sold either by volume (ccf or Mcf) or heating value (dekatherms).

Consumer Contract - A written statement of the terms of service between a customer and a natural gas supplier.

Customer Assistance Programs - CAPS - A payment program for low-income people who have trouble paying their bills. This payment program is set up between a utility company and the customer. It allows the customer to pay a percent of the bill they owe or to pay a percent of their income instead of paying the actual bill each month. When an agreement is made, the customer must make regular monthly payments based on their new payment plan.

Customer Charge - A monthly charge to cover NGDC costs such as maintaining the gas lines, meter reading and billing.

Customer Choice - Customers and sellers can deal directly with each other for natural gas supplies, which are transported through NGDCs' pipes to the consumer.

Customer Classes - The classes of natural gas customers are residential, commercial and industrial.

Customer Reading - An actual meter reading made by the customer that is given to the NGDC.

Dth - (Dekatherm) - A measure of the heat content value of gas. Gas usage is determined by multiplying the Mcf used by the heat content value of the gas.

Deregulation - Removal or change in regulations or controls governing a business or service operation such as a utility.

I&E Exhibit No. 3-SR
Schedule 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2012-2290597

PPL Electric Utilities Corporation

Exhibit JMK 5

Residential Customer Charge

PPL ELECTRIC UTILITIES CORPORATION
COST OF SERVICE SUMMARY - RS CUSTOMER CHARGE
REVENUE REQUIREMENTS
($1,000)

Customer Class: RS		Rate Class Total	Total Demand	Total Customer	Meters	Services	Meter Reading	Other Cust Exps	Total Direct[1]	Allocated Costs[2]	Total Customer Charge	Excluded Expenses
Rate Base:												
Plant In Service		3,391,885	836,767	2,555,118	171,016	497,816			668,832	1,886,486	2,555,118	
Depreciation Reserve		1,249,089	280,412	968,677	94,731	241,367			336,098	632,579	968,677	
Net Plant		2,142,796	556,355	1,586,441	76,285	256,249			332,534	1,253,907	1,586,441	
Subtractive Adjustments		501,254	125,655	375,599	18,061	60,868			78,729	296,870	375,599	
Additive Adjustments		46,958	10,521	36,437	1,752	5,885			7,638	28,799	36,437	
Total Rate Base		1,688,500	441,221	1,247,279	59,976	201,466			261,442	985,837	1,247,279	
Operating Expenses:												
Misc Distrib Expenses		12,463	3,258	9,205						9,205	9,205	
Customer Service Costs[3]		12,764		12,764				12,764	12,764	12,764	12,764	
PUC Annual Assessment		3,635	598	3,037						3,037	3,037	
Employee Benefits		23,611	3,837	19,774	6,034	783	1,390	6,969	15,176	4,598	19,774	
Other A&G		88,765	14,421	74,344	6,946	4,096	2,532	26,201	39,774	34,570	74,344	
Other O&M Expenses		163,328	27,626	135,702	12,678	7,476	4,621	47,826	72,600	63,102	135,702	
Proforma Adjustments		3,738	627	3,111					0	3,111	3,111	
Depreciation Expense		97,165	21,270	75,895	10,399	9,050			19,449	56,446	75,895	
Taxes Other Than Income		6,504	1,205	5,299	255	856			1,111	4,188	5,299	
Return	8.46%	142,847	37,327	105,520	5,074	17,044			22,118	83,402	105,520	
Income Taxes	41.49%	68,718	17,957	50,761	2,441	8,199			10,640	40,121	50,761	
Tax Adjustment		13,983	4,947	9,036					0	9,036	9,036	
Gross Revenue Requirements		637,521	133,073	504,448	43,826	47,503	8,542	93,760	193,632	323,581	504,448	-
Annualization Adjustment		(1,209)	(252)	(957)	(83)	(90)	(16)	(178)	(367)	(589)	(957)	
Late Payment Charges		10,868	2,227	8,441	733	795	143	1,569	3,240	5,201	8,441	
Other Operating Revenues		27,296	7,136	20,160	1,751	1,898	341	3,747	7,738	12,422	20,160	
Total Revenues		38,755	9,110	27,645	2,402	2,603	468	5,138	10,611	17,033	27,645	-
Net Revenue Requirements		600,766	123,963	476,804	41,424	44,900	8,074	88,622	183,020	306,547	476,804	-
GRT Base		610,226	125,937	484,288	42,075	45,605	8,201	90,013	185,893	311,159	484,288	-
GRT Gross-up		648,486	133,833	514,653	44,713	48,464	8,715	95,657	197,549	330,668	514,653	-
GRT	5.90%	38,261	7,896	30,365	2,638	2,859	514	5,644	11,655	19,509	30,365	-
Total Revenue Requirements		675,782	140,969	534,813	46,464	50,362	9,057	99,404	205,287	343,090	534,813	-
Customer Charge		64,898		$38.70	$3.19	$3.46	$0.62	$6.82	$14.09	$23.54	$38.70	-
Number Customers				1,214,512								
Annual Customer Billings				14,574,144								

Notes:

[1] Includes meters, services and directly assignable operating costs.

[2] Includes all other (overhead lines, underground lines, line transformers and general and intangible) allocated capital and operating costs.

[3] Excludes Universal Service Rider costs.