delmarva
power
A PHI Company

79NC62
PO Box 9239
Newark, DE 19714-9239

July 15, 2013

VIA HAND-DELIVERY AND EMAIL

Ms. Alisa Bentley, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, DE 19904

RE: PSC Docket No. 12-546: Delmarva Power & Light Company's Rebuttal Testimony and Schedules

Dear Ms. Bentley:

In accordance with the procedural schedule in PSC Docket No. 12-546, on behalf of Delmarva Power & Light Company, attached is an original and 10 copies of the Company's Rebuttal Testimony and Schedules.

Please contact Heather Hall at (302) 454-4828 or me with any questions relating to the above referenced matter.

Very Truly Yours,

Todd L. Goodman /HgH

Todd L. Goodman, Esquire

cc: Service List in PSC Docket No. 12-546

Delmarva Power & Light Company

Application for an Increase in Gas Base Rates

Docket No. 12-546

Rebuttal Testimony of McGowan, Hevert, Ziminsky,
Collacchi and Santacecilia

Before the Delaware Public Service Commission

July 15, 2013

Rebuttal Testimony of
Kevin M. McGowan

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMMISSION
REBUTTAL TESTIMONY OF KEVIN M. MCGOWAN
DOCKET NO. 12-546

Q1. Please state your name and position.

A1. My name is Kevin M. McGowan. I am Vice President of Regulatory Affairs for Pepco Holdings, Inc. (PHI). I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What is the purpose of your Rebuttal Testimony?

A2. As the Company's overall policy witness, I will summarize the Company's rebuttal presentation and I will also rebut portions of the direct testimonies filed by the Commission Staff and the Division of Public Advocate (DPA), with a specific focus on the policy and financial implications of their recommendations.

Q3. Please identify the Company's Rebuttal Witnesses.

A3. Company Witness Robert B. Hevert rebuts the recommendations of the witnesses for the Commission Staff and DPA on rate of return and cost of capital issues.

Company Witness Jay C. Ziminsky addresses revenue requirement issues including rebutting certain recommendations of the witnesses for the Commission Staff and DPA. Mr. Ziminsky will also address issues related to Advanced Metering Infrastructure (AMI) regulatory asset recovery.

Company Witness Robert M. Collacchi rebuts the recommendations of the witnesses for the Commission Staff and DPA on post-test period reliability plant additions, Advanced Metering Infrastructure (AMI) regulatory asset recovery and the proposed main extension tariff revisions.

Company Witness Marlene C. Santacecilia rebuts the recommendations of the witnesses for the Commission Staff and DPA on rate design and proposed tariff revisions.

Q4. Please comment on the financial proposals of the Commission Staff and DPA.

A4. Based on the $13.005 million increase proposed by the Company in its March 11, 2013 Supplemental and Updated filing, Commission Staff recommends a reduction to the Company's overall revenue requirement request by $9.419 million to $3.585 million and the DPA similarly recommends a reduction to the Company's overall revenue requirement request by $12.299 million to $706 thousand. Neither recommendation would give the Company the opportunity to earn its authorized rate of return. As I stated on pages 5 and 6 of my Direct Testimony, the Company has invested approximately $38.6 million in its gas distribution system since the last gas base rate case in 2010 to replace aging gas facilities, maintain reliability and ensure the continued safety of the gas system. At current rates, Delmarva's adjusted rate of return, based on the analysis presented by Company Witness Ziminsky in his Supplemental Direct Testimony, is 4.73% which reflects a return on equity (ROE) of only 4.55%. This 4.55% is far below the 10.00% ROE currently approved by the Commission. At this low rate of return, the Company is at a competitive disadvantage when it comes to raising necessary capital on reasonable terms to continue to make important investments in the gas system. The Company's rates for distribution service must reflect the current costs of providing service. If the recommendations of Staff and DPA are adopted by the Commission, not only would Delmarva not have the opportunity to earn a fair return on its capital investments; these proposals would be viewed negatively by both the financial community and the rating agencies. This outcome will make it more difficult and costly to the Company to raise additional capital on reasonable terms, which will result in higher costs for our customers.

Q5. What significant recommendations of the Staff and DPA would have the most detrimental impacts on the Company and its gas customers?

A5. The most significant recommendations in terms of detrimental impact on the Company and its gas customers are the unreasonably low rate of return recommendations of DPA Witness Woolridge and Staff Witness Parcell.

In this proceeding, Staff recommends a 9.45% ROE and DPA recommends a 8.50% ROE. Both of these recommendations are among the lowest gas ROEs authorized in the last 30 years. If adopted, the Company would be at a disadvantage as it competes in the capital markets to raise funding for necessary investments in its infrastructure. Company Witness Hevert provides additional detail regarding the parties' ROE recommendations.

Q6. Please comment on the importance of the Commission adherence to reasonable, consistent and predictable ratemaking practices.

A6. The primary purpose of setting utility rates is to provide the utility the opportunity to recover its reasonable and prudent costs of providing service during the period when rates will be in effect, including the opportunity to earn its authorized rate of return. Since at least the 1980's, this Commission has recognized this principle by consistently allowing test period costs to be adjusted using post test period known and measurable changes to those costs. If regulatory commissions do not recognize rate-related expense increases and non-revenue producing rate base additions that occur during the rate-effective period in rates, the utility will be denied an opportunity to recover the cost of providing service to its customers and to earn its authorized rate of return. In fact, to not include costs that the Company will incur during the rate-effective period will virtually guarantee that Delmarva will fall short of its authorized rate of return.

In addition, as I stated on page 8 of my Direct Testimony, the state regulatory environment is a very important factor to credit rating agencies. In fact, in S&P's publications entitled "Assessing U.S. Regulatory Environments," dated November 7, 2008 and updated on March 11, 2010, and "Business and Financial Risks in the Investor-Owned Utility Industry," dated November 26, 2008 and updated on March 11, 2010, S&P indicated that the regulatory climate is perhaps the most important factor it analyzes when evaluating investor-owned utilities. It noted that regulatory risk will continue to be evaluated based on the environments in which companies operate, as well as other factors, including ratemaking practices and procedures, cash flow support and stability and political insulation. Actions by the Commission and departure from long established rate-making practices are closely monitored by both the Rating Agencies and investor community.

Credit Facilities Expense

Q7. Please describe the credit facility expense adjustment as proposed by the Company.

A7. Following the ratemaking precedent set in Docket No. 09-414 (reference paragraph No. 75 in Order No. 8011), this adjustment allows the Company to recover the costs related to its credit facility. These costs are recorded as interest expense for financial reporting purposes of the Company; however, they are not reflected in the cost of capital for ratemaking purposes.

Q8. Staff Witness Peterson recommends that the proper treatment of these costs is to recognize them as an increase in the effective cost of short-term debt in the calculation of Delmarva's AFUDC rate. Do you agree?

A8. No. Staff Witness Peterson incorrectly assumes that the purpose of, and need for, the Company's credit facility is limited to short-term debt. As noted below, the credit facility provides many benefits to the Company, and is not limited to short-term debt issuances. As the principle behind AFUDC is to recover financing costs incurred during construction, any proposed mechanism that attempts to recover the costs of the credit facility, which supports the financing of both new construction and existing plant assets, only through the AFUDC rate would necessarily be arbitrary and inaccurate. Therefore, Staff Witness Peterson's proposal to recover these costs by increasing the short-term debt component of Delmarva's AFDUC rate is inappropriate.

Q9. DPA Witness Watkins recommends that credit facility costs should only be included in the Company's revenue requirement if short-term debt is included in its capital structure. Do you agree?

A9. No. DPA Witness Watkins' recommendation ignores the important benefits the credit facility provides.

Q10. Please summarize the purposes of the credit facility.

A10. First, the credit facility is required by underwriters to support the Company's commercial paper program. The commercial paper program is separate from the credit facility and allows the Company to issue short-term debt. Second, the credit facility provides vital liquidity for Delmarva that is important for investor support of Delmarva's long-term borrowings, because it ensures the Company has adequate and immediate access to funds at all times and since the facility is always available for Delmarva to call upon to obtain funds during its term it is therefore a critical element in the Rating Agencies' assessment of the Company's long-term credit rating. In general, the facility provides assurance that the Company's obligations, whether short- or long-term will be paid even during unforeseen and prolonged periods of stress in credit markets. If Delmarva did not maintain its credit facility, the Rating Agencies would not support the current long-term credit ratings of Delmarva.

Since the credit facility enables the Company to obtain a higher credit rating, than it would otherwise be able to obtain, the Company can obtain long-term financing at lower rates and negotiate better terms and conditions from its vendors, all which provides a direct benefit to the customer. In addition, the credit facility provides flexibility to Delmarva's long-term financing program because the credit facility can be used to bridge the timing gap between the required due date of maturing debt and the issuance of new debt when the market is accessible or when terms are most favorable.

Q11. Is it appropriate to have the Company's need for a credit facility, and therefore the recovery of its related credit facility costs, contingent upon including short-term debt in Delmarva's capital structure?

A11. No. To support its long-term credit ratings and operations, the Company would be required to maintain a credit facility whether or not it issued short-term debt. The Company relies on a combination of long-term debt and equity to permanently finance its long-lived distribution assets, and only uses short-term debt for temporary financing of new construction and working capital. DPA Witness Watkins' recommendation to link credit facility cost recovery to the inclusion of short-term debt in the Company's capital structure is inappropriate since it ignores the long-term credit rating support the credit facility provides, along with the other benefits previously described, all of which are not limited to short-term debt.

Incentive Expense

Q12. Please explain the Company's proposed treatment of Executive Incentive Compensation Expense.

A12. Although the Company believes that performance based incentives for Company executives are an established compensation method that is critical to attracting and retaining talent that is beneficial to both customers and the Company, Delmarva decided not to seek recovery of such expenses in this case. The Company reserves its right to request the Commission to consider its inclusion of these expenses in the cost of service in future base rate case filings.

Q13. What are the other parties' positions on the Company's proposed treatment of Non-Executive Incentives?

A13. The Company seeks to include in cost of service, the costs associated with non-executive incentive compensation. Both Staff and DPA propose removing some level of the non-executive incentive expense, which is mainly comprised of Annual Incentive Plan (AIP), from the cost of service. The Company does not agree that these recommendations are appropriate.

Q14. What is the Company's position on non-executive incentive expense?

A14. The Company understands the Commission's decision in Docket No. 05-304 to limit the recovery of non-executive incentive expense to those costs related to safety, reliability or customer service goals. However, the Company also recognizes that the Commission, prior to Docket No. 05-304, recognized the full amount of these costs in rates. While Delmarva Power recognizes the Commission's ruling on this issue in Docket No. 05-304, it respectfully requests that it be permitted to recover the full amount of its non-executive incentive/AIP compensation expense, including the amount ($530,799) associated with financial-related items.

Incentive compensation is an important part of the overall compensation of employees that both (1) allows the Company to attract and retain skilled employees and (2) creates incentives to attain levels of performance that benefit customers. PHI employees' salaries are benchmarked by a third-party consultant every few years. The Company sets salary ranges at the average of the companies that PHI competes against for staffing resources. After careful consideration, the Company decided to place a portion of employee compensation "at risk." In other words, a portion of the compensation available to the Company's employees is in their base salary, and the remainder must be earned by achieving performance goals. If those performance goals are not attained, employees will not receive the total compensation available to them. The Company could have included in base salary the portion of potential compensation that has been set aside as part of the incentive compensation plan. Instead, the Company determined that it is more appropriate to incentivize employees to achieve their best performance by making a portion of their compensation contingent upon achieving a balanced set of performance goals. The use of incentive compensation is a prevalent and well-established practice in the industry designed to achieve the goals of making compensation competitive while at the same time, incentivizing employees to achieve their best performance to the benefit of both customers and the Company.

Q15. How does incentive compensation benefit customers?

A15. The AIP, while including financial thresholds, creates incentives for employees to perform their duties in a way that protects the interests of customers. Including financial targets is not designed to simply increase profits. For example, requiring employees not to exceed budgets certainly benefits customers. The more economically efficient the Company's workforce operates, the lower the costs that will be in the Company's cost of service. This includes not only the various expenses for which the Company seeks recovery, but also is seen in the Company's financial metrics, thus lowering the cost at which the Company can attract capital.

The concept offered by Witnesses Peterson and Watkins - that any incentives related to financial benefit to the Company should be denied as not beneficial to customers - is clearly unsupported.[1] The financial metrics included in the Non-Executive AIP plan relate to O&M and capital spending. These metrics incentivize

[1] See, Direct Testimony of David E. Peterson, at 22 and Direct Testimony of Glenn A. Watkins, at 13.

our employees to control spending and seek opportunities to save money in order to meet their budgets on an annual basis. If spending is controlled, the customers will benefit through lower expenses reflected in the cost of service. As a result, any suggestion that financial metrics that are used in the AIP have no benefit to customers and should be disallowed is without merit. A Company that incents its employees to contribute to the financial health of the Company benefits the customers through lower rates.

Because the Company's AIP is carefully designed to make the Company more economically efficient, safe and reliable, 100% percent of the costs associated with the AIP should be included in cost of service, consistent with the Commission's treatment of the expense prior to Docket No. 05-304.

To the extent that the Commission determines that not all of the incentive payments promote customer benefits, it should not disallow 100% of the costs as suggested by Staff Witness Peterson. The Commission should, at the very least, approve inclusion in the cost of service of the portions that have been identified as related to solely safety, reliability and customer service goals as it did in Docket No. 05-304. Company Witness Ziminsky provides additional detail regarding the parties' positions on the treatment of Non-Executive Incentives included in the test period.

Capital Structure

Q16. Please comment on the DPA's recommended capital structure.

A16. Witness Woolridge states on page 11 lines 9-19 that the capital structure consisting of 50.78% long-term debt and 49.22% common equity is "reasonable for a gas distribution company." Factually, this is the capital structure of the Company as of December 31, 2012 which was filed in my Supplemental Testimony on March 11, 2013. However, Witness Woolridge's exhibit JRW-1 shows a capital structure of 51.22% long-term debt and 48.78% common equity which is the September 30, 2012 capital structure originally filed in my Direct Testimony. If Witness Woolridge reflected the actual capital structure he found reasonable in his testimony, the resulting rate of return would be 6.67% instead of the 6.66% that he recommends. The Commission should approve the capital structure as proposed by the Company and found to be reasonable by Witness Woolridge and shown below.

Delmarva Power & Light Company
DPL Delaware
December 31, 2012

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.78%	4.91%	2.49%
Common Equity	49.22%	8.50%	4.18%
Total	100.00%		6.67%

Q17. Does this conclude your Rebuttal Testimony?

A17. Yes, it does.

Rebuttal Testimony of
Robert B. Hevert

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
REBUTTAL TESTIMONY OF ROBERT B. HEVERT
DOCKET NO. 12-546

I. Introduction

Q1. Please state your name, affiliation, and business address.

A1. My name is Robert B. Hevert. I am Managing Partner of Sussex Economic Advisors, LLC (Sussex). My business address is 161 Worcester Road, Suite 503, Framingham, MA 01701.

Q2. Are you the same Robert B. Hevert who submitted direct testimony in this proceeding?

A2. Yes. I filed Direct Testimony on behalf of Delmarva Power & Light Company (Delmarva or the Company), a wholly-owned operating subsidiary of Pepco Holdings, Inc. (PHI), in this proceeding on December 7, 2012.

Q3. What is the purpose of your Rebuttal Testimony?

A3. The purpose of my Rebuttal Testimony is to respond to the Direct Testimonies of David Parcell on behalf of the Commission Staff (Staff) of the Delaware Public Service Commission (Commission), and Dr. J. Randall Woolridge on behalf of the Delaware Division of Public Advocate (DPA).

Q4. Have you prepared any Rebuttal Schedules?

A4. Yes. Schedule (RBH-R)-1 through Schedule (RBH-R)-15 have been prepared by me or under my direct supervision.

II. Summary and Overview

Q5. Please summarize the key issues and recommendations addressed in your Rebuttal Testimony.

A5. In my Direct Testimony, I recommended an ROE of 10.25%, based on a range of ROE estimates of 10.00% to 10.75%.[1] My updated analyses continue to support my position that the Company's proposed ROE of 10.25% is within a reasonable range of estimates of its Cost of Equity. As my Direct Testimony discussed, my recommendation, and the analytical results on which it was based, considered a variety of factors including the specific risks faced by Delmarva and existing and expected capital market conditions. That is especially important when conditions have changed significantly over an abbreviated period, as recently has been the case.

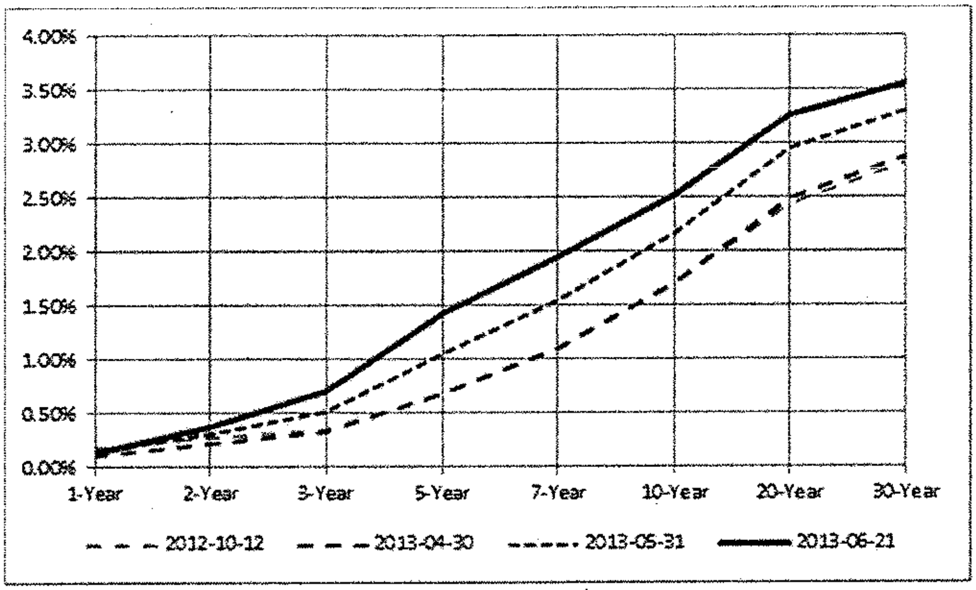
Q6. Please expand on that last point.

A6. There is little question that since October 12, 2012 (*i.e.*, the date of my analyses in my Direct Testimony), both current and forward interest rates increased. As Chart 1 (below) demonstrates, the Treasury yield curve has shifted upward, with longer-term maturities experiencing the greater increases. In fact, interest rates have increased significantly since the beginning of May 2013.

---

1 *See* Direct Testimony of Robert B. Hevert, at 46.

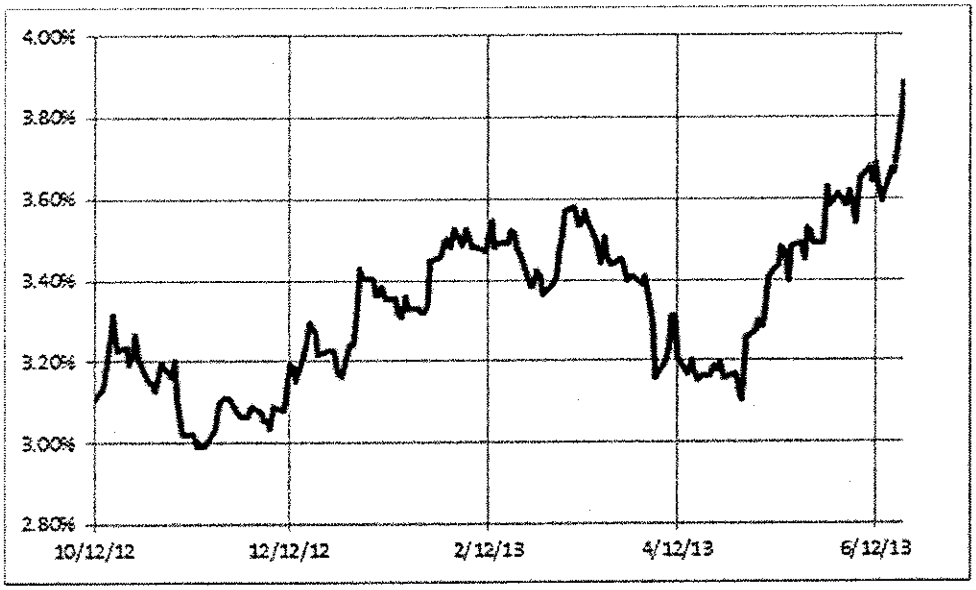
Chart 1: Treasury Yield Curve[2]



The same holds true in looking at forward interest rates. Applying the same method I used to calculate expected inflation for the purpose of my Multi-Stage DCF model, I also calculated the expected long-term Treasury yield three years forward for each trading day from October 12, 2012 through June 21, 2013. I performed that calculation based on the "expectations" theory, which states that (for example) the current 30-year Treasury yield equals the combination of the current three-year Treasury yield, and the 27-year Treasury yield expected in three years. That is, an investor would be indifferent to (1) holding a 30-year Treasury to maturity, or (2) holding a three-year Treasury to maturity, then a 27-year Treasury bond, also to maturity. As illustrated on Chart 2 (below) since October 12, 2012, the forward yields have increased by 77 basis points.

2 Source: Federal Reserve Board Schedule H.15.

Chart 2: Forward 27-Year Treasury Yield[3]

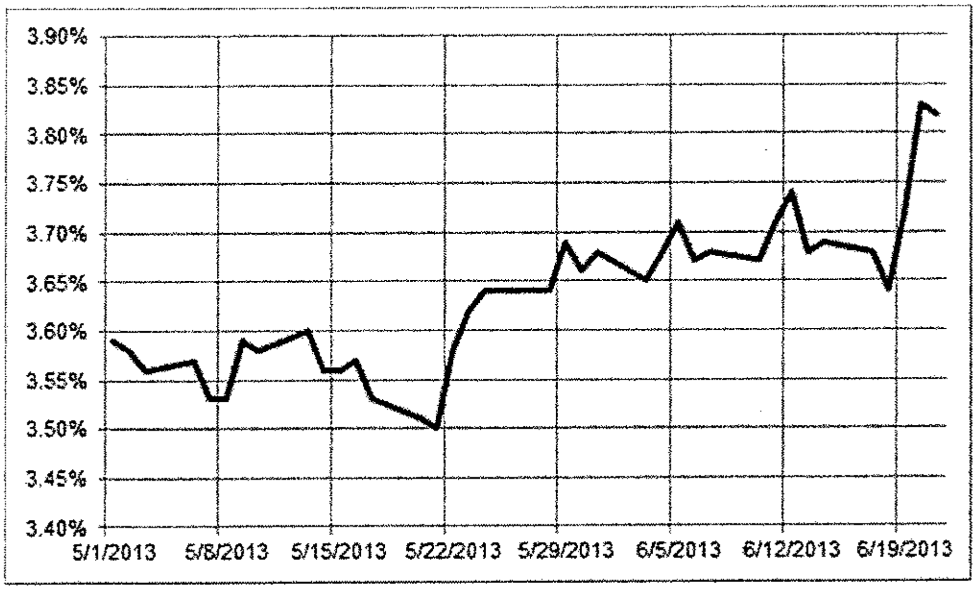


Q7. Is it the case that utility dividend yields also have recently increased?

A7. Yes, it is. To make that assessment, I calculated the average dividend yield for my proxy group from May 1, 2013 through June 21, 2013. As Chart 3 (below) indicates, the dividend yield increased by 23 basis points over that time (and 32 basis points since May 21, 2013).

3 Source: Federal Reserve Board Schedule H.15. Represents forward 27-year yield three years hence.

Chart 3: Proxy Group Daily Dividend Yields



Q8. Is it your position that data since the beginning of May 2013 should solely be used to determine the Company's ROE?

A8. No, it is not. In fact, the data underlying my analyses reflect the 30-, 90-, and 180-day trading periods ended June 14, 2013. Nonetheless, I do believe that the recent increase in Treasury yields, together with the increase in utility dividend yields are important considerations in arriving at ROE recommendations.

Q9. In light of that data, what are your principal conclusions regarding the opposing witnesses' ROE recommendations?

A9. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation are consistent with the recommendation itself. While I appreciate that every analysis necessarily requires an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst. Because the application of financial models and interpretation of their results is often the subject of differences among analysts in regulatory proceedings, I believe that it is important to review and consider a variety of data points; doing so enables us to put in context both quantitative analyses and the associated recommendations.

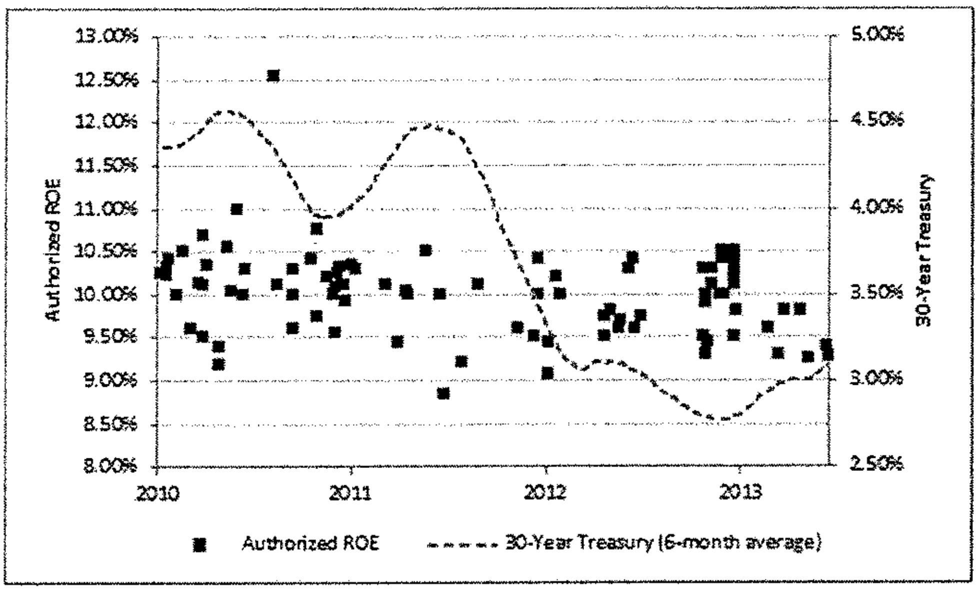
As noted in my Direct Testimony, it is important to recognize that in establishing their return requirements, investors consider a broad range of data including authorized returns from alternative jurisdictions, and current capital market data. Equity investors have many options available to them, and will allocate capital based on the expected returns associated with those alternatives. While I am not suggesting that the Commission should be bound by decisions in other regulatory jurisdictions, given that investors consider such data in framing their investment decisions, return recommendations that materially deviate from observed industry norms should be supported by clear and unambiguous reasons explaining those deviations.

As discussed throughout my Rebuttal Testimony, there are a number of methodological, theoretical and practical reasons why recommendations as low as 8.50% in the case of DPA Witness Woolridge are unreasonably low. DPA Witness Woolridge, for example, develops his recommendation by giving weight to ROE estimates that are well below all returns authorized by any regulatory commission in at least 30 years.[4] Both Staff Witness Parcell and DPA Witness Woolridge, point to decreases in long-term interest rates and conclude, by extension, that the Cost of

[4] I note that the low end of Staff Witness Parcell's DCF range, which he gives 50.00% weight in developing the low end of his recommended range, results in an ROE that would be below all but one authorized return in any jurisdiction since at least 1980.

Equity should be commensurately low.[5] As noted above, that position is at odds with recent market data and as shown below, is not supported by the returns on comparable investments. As Chart 4 demonstrates, authorized returns for natural gas utilities have remained relatively stable even as interest rates have significantly decreased.

Chart 4: Authorized ROEs for Natural Gas Utilities 30-Year Treasury Yields



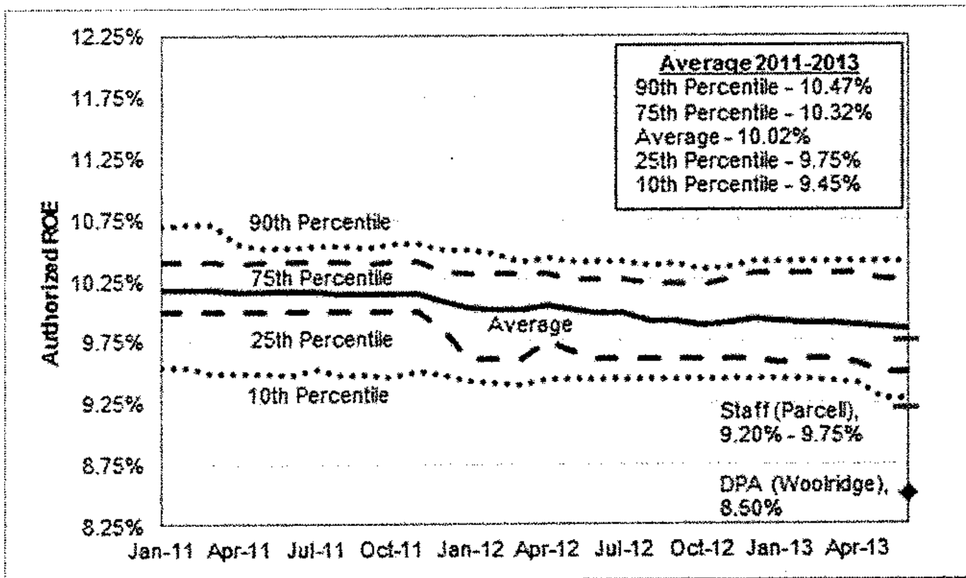
No one financial model is any more "correct" than any other method in all circumstances, and as such, it is important to consider the results of a variety of methods.[6] That observation is especially important when market conditions are such that financial models produce results that are widely divergent, and highly sensitive to inputs and assumptions. As discussed throughout my Rebuttal Testimony, neither market conditions in general, nor the Company's situation in particular supports the

5 *See* Direct Testimony of Staff Witness Parcell, at 10-14 and Direct Testimony of DPA Witness Woolridge, at 4-9.

6 I have updated the Cost of Equity estimation models that were presented in my Direct Testimony. My updated analyses are included in Schedule (RBH-R)-1 through Schedule (RBH-R)-8.

proposition that the required Return on Equity is far below recently authorized returns. In contrast, my recommendation is well within the range of a broader, highly relevant set of observations: the returns available to other natural gas utilities (*see* Chart 5). My ROE recommendation, therefore, is appropriate relative to the returns available to the utilities with which Delmarva must compete for capital, and is based on fundamentally sound, and empirically supported methods and results.

Chart 5: Authorized ROEs for Natural Gas Utilities[7]



Q10. What are the primary differences between your analytical approach and those used by the opposing witnesses?

A10. Our respective analyses differ in several ways, but the key differences lie in: (1) the specification and inputs (in particular, the growth rate assumptions) used in our respective Discounted Cash Flow (DCF) analyses; (2) the application of the Capital Asset Pricing Model (CAPM), in particular, the derivation of the Market Risk Premium (MRP) component of that model; (3) the effect of the current capital market

[7] Source: Regulatory Research Associates. Based on authorized ROEs over 24-month rolling periods.

environment on the Company's Cost of Equity; and (4) the effect of certain business risks on the Company's Cost of Equity.

III. Response to Direct Testimony of Staff Witness Parcell

Q11. Please provide a brief summary of Staff Witness Parcell's Direct Testimony and recommendations.

A11. Staff Witness Parcell estimates the Company's Cost of Equity based on: (1) the Constant Growth DCF model; (2) the CAPM; and (3) the Comparable Earnings Model (CEM). Staff Witness Parcell excludes his CAPM results of 6.20% to 6.30% and defines his ROE range of 9.20% to 9.75% by reference to the mid-point of his respective DCF and CEM results.[8]

Q12. As a preliminary matter, do you believe that Staff Witness Parcell's recommended range is reasonable?

A12. No, I do not. Putting aside the analytical issues discussed below, I note that the low end of Staff Witness Parcell's range, 9.20%, and the high end, 9.75%, are the simple average of two sets of data points (*see* Table 1, below).

Table 1: Summary of Staff Witness Parcell's ROE Range[9]

Method	*Low Estimate*	*High Estimate*	*Mid-Point*
Discounted Cash Flow	9.00%	9.40%	9.20%
Comparable Earnings	9.50%	10.00%	9.75%
Overall Range			9.20% - 9.75%

Staff Witness Parcell's recommended range therefore gives equal weight to all

[8] *See* Direct Testimony of Staff Witness Parcell, at 24.
[9] *Ibid.*

four estimates assuming, for example, that an ROE of 9.00% is equally as plausible as an ROE of 10.00%. An ROE of 9.00% would be the second lowest of approximately 970 ROE authorizations since 1980. Simply removing that estimate and giving equal weight to the remaining three estimates would increase the range to 9.40% to 9.75%.

As discussed in more detail later in this section, Staff Witness Parcell's CEM approach relies substantially on his subjective judgment as to the relationship between Market-to-Book Value (M/B) ratios and the earned Return on Common Equity, as well as his sense of what may (or may not) be an appropriate Market-to-Book ratio. Given the highly subjective nature of that approach, there are a range of plausible results. For example (as also discussed in more detail below) based on the data provided by Staff Witness Parcell, a M/B ratio of approximately 162.50% would be associated with the 10.00% lower bound of my recommended range.[10] That ratio (*i.e.*, 162.50%) is in approximately the 41st percentile of the ratios presented in Staff Witness Parcell's Exhibit___(DCP-1), Schedule 10.

Q13. What are the specific areas in which you disagree with Staff Witness Parcell's analyses and recommendations?

A13. The principal areas in which I disagree with Staff Witness Parcell's analyses include: (1) the effect of current market conditions on Delmarva's Cost of Equity; (2) the growth rates used in the Constant Growth DCF analysis; (3) the application of the CAPM; and (4) Staff Witness Parcell's application of the Comparable Earnings Method.

[10] *See* Table 2. 162.50% is the approximate average of 162.00% and 163.00%.

Capital Market Conditions

Q14. Please briefly summarize the financial and economic conditions that Staff Witness Parcell discusses in his direct testimony.

A14. Staff Witness Parcell refers to comparatively low levels of inflation (as measured by the Consumer Price Index), which he asserts are "reflective of lower capital costs",[11] and historically low Treasury and utility bond yields, which he attributes to a "flight to safety."[12] Staff Witness Parcell further notes that the "flight to safety" led to a "negative perception" of the recent market which resulted in the reduced valuation of "retirement accounts, investment portfolios, and other assets."[13] Staff Witness Parcell suggests that this has caused "a decline in investor expectations of returns, including stock returns."[14]

Q15. What is your response to Staff Witness Parcell on these issues?

A15. As to his review of interest rates, Staff Witness Parcell refers to page 4 of his Schedule 6. There, the most recent data relates to April, 2013. As noted earlier in my Rebuttal Testimony, interest rates have increased rather substantially since then. To that point, while Staff Witness Parcell's Schedule 6 shows the ten-year Treasury yield of 1.76% in April, by June 21, 2013, it had risen to 2.52%. And, as discussed further in my response to DPA Witness Woolridge, utility bond yields have experienced a similar increase. In my view, the rather substantial increase in interest rates since April should be considered in determining the Company's Cost of Equity.

---

[11] Direct Testimony of Staff Witness Parcell, at 13.
[12] *Ibid.*, at 14.
[13] *Ibid.*
[14] *Ibid.*

DCF Growth Rates

Q16. Please summarize the growth rates that Staff Witness Parcell relies on in his Constant Growth DCF analysis.

A16. Staff Witness Parcell relies on five measures of growth: (1) historical, five year average earnings retention growth rates from Value Line for 2008-2012; (2) five-year average historical growth in Earnings Per Share (EPS), Dividends Per Share (DPS) and Book Value Per Share (BVPS) from Value Line; (3) projected earnings retention growth for 2013, 2014 and 2016-2018 from Value Line; (4) projected EPS, DPS and BVPS growth rates from Value Line for years 2010-2012 to 2016-2018; and (5) five-year projections of EPS growth as reported by First Call.[15]

Q17. Please summarize the differences between you and Staff Witness Parcell in the selection of growth rates in your respective Constant Growth DCF analyses.

A17. For the reasons discussed throughout my Direct and Rebuttal Testimonies, it is my view that analysts' earnings projections are the relevant measure of growth. Staff Witness Parcell's analysis, on the other hand, includes both historical and projected growth in DPS, BVPS, and EPS, as well as historical and projected measures of Sustainable Growth. For the reasons discussed below (as well as in my response to DPA Witness Woolridge), I disagree with Staff Witness Parcell's use of historical data, and with his use of projected DPS, BVPS, and Sustainable Growth rates.

---

[15] *See* Direct Testimony of Staff Witness Parcell, at 20.

Q18. Why do you disagree with Staff Witness Parcell's position that dividend or book value growth rates are appropriate inputs to the Constant Growth DCF model?

A18. As explained in my Direct Testimony, over the long term, dividend growth can only be sustained by earnings growth.[16] The use of earnings growth estimates is also supported by the assumptions underlying the Constant Growth DCF model, which state that earnings, dividends and stock prices all grow at the same rate, and that the payout, Market-to-Book, and Price/Earnings (P/E) ratios remain constant, in perpetuity. Under those assumptions, the Constant Growth DCF model produces the same result whether the stock is held in perpetuity or sold after an assumed holding period (*see* Schedule (RBH-R)-9). Given that investors tend to value common equity on the basis of P/E ratios, the expected (and required) return on equity is a function of the long-term growth in earnings, not dividends or book value.

I also note that Value Line is the only service noted in Staff Witness Parcell's direct testimony that provides DPS, or BVPS growth projections. While services such as Zacks and First Call survey multiple analysts to arrive at their consensus growth estimates, Value Line projections reflect the view of a single analyst. Because they reflect multiple perspectives, consensus estimates are less likely to be biased in one direction or another than a projection that reflects the views of a single analyst. It is for that reason that one of the criteria used to develop my proxy group is that the subject company must be followed by at least two utility industry equity analysts.

---

16 *See* Direct Testimony of Robert B. Hevert, at 21.

Application of the CAPM

Q19. What is your response to Staff Witness Parcell's application of the CAPM analysis?

A19. While I do not agree with the risk-free rate or the market risk premium included in his analyses, Staff Witness Parcell has excluded his CAPM results in determining his ROE range and recommendation. As such, and in order to narrow the scope of contested issues, I have limited my discussion of the appropriate application of the CAPM to my response to DPA Witness Woolridge.

Market-to-Book Ratios and Comparable Earnings Method

Q20. Please describe Staff Witness Parcell's application of the Comparable Earnings analysis.

A20. Staff Witness Parcell's Comparable Earnings analysis examines realized Return on Common Equity (ROCE) for several groups of companies (our respective proxy groups, and the S&P 500 companies) and evaluates investor acceptance of those returns by reference to the resulting M/B ratio.[17] Staff Witness Parcell reasons that his results indicate historical returns of 10.80% to 11.80% have been adequate to produce M/B ratios of 160.00% to 180.00%.[18] His review of S&P 500 companies, which Staff Witness Parcell considers to be representative of the competitive sector of the economy, indicate average earned returns from 12.40% to 14.70%, with M/B ratios ranging from 201.00% to 341.00%.[19] Finally, Staff Witness Parcell compares the risk levels of the utility industry with those of the competitive sector, by

---

17 *See* Direct Testimony of Staff Witness Parcell, at 20-24.

18 *Ibid.*, at 22.

19 *Ibid.*, at 23.

considering such metrics as the Value Line Safety Rank, Value Line Beta Coefficient, Value Line Financial Strength, and S&P Stock Rank.[20]

Based on his Comparable Earnings analysis, Staff Witness Parcell concludes that "the cost of equity for the proxy utilities is no more than 9.5 percent to 10.0 percent."[21] Staff Witness Parcell further concludes that "an earned return of 9.75 percent should thus result in a market-to-book ratio of over 100 percent,"[22] and that "the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies."[23]

Q21. Do you agree with Staff Witness Parcell's Comparable Earnings analysis?

A21. No, I do not. With respect to the structure of his analysis, I disagree with Staff Witness Parcell's assumption that the earned ROCE[24] is the sole determinant of the M/B ratio. Even if his assumption was correct, Staff Witness Parcell provides no empirical basis regarding the relationship between M/B ratios and the earned ROCE. Nor, for that matter, does Staff Witness Parcell provide an empirical basis for his determination regarding the appropriate M/B ratio. Staff Witness Parcell implies that Market-to-Book ratios of 160.00% and greater indicate excessive earnings levels, but provides no evidence to support such an implication. Rather, Staff Witness Parcell's analysis is substantially subjective in nature and as such, his assumptions and conclusions (as presented) cannot be replicated, verified or falsified. Given that the

20 *Ibid.*, Exhibit__(DCP-1), Schedule 12.
21 Direct Testimony of Staff Witness Parcell, at 23.
22 *Ibid.*
23 *Ibid.*
24 Staff Witness Parcell's analysis assumes that the Return on Common Equity is interchangeable with the ROE.

CEM analysis defines the upper end of Staff Witness Parcell's ROE range, the subjective nature of his conclusions have a significant effect on his recommendation (*i.e.,* 9.20% to 9.75%).

Q22. As a preliminary matter, please provide a brief definition of the Market-to-Book ratio.

A22. The M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book equity) per share. Book value per share is an accounting construct, which reflects historical costs. In contrast, market value per share (*i.e.,* the stock price) is forward-looking, and is a function of many variables, including (but not limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality", the regulatory climate, the equity ratio, expected capital expenditures, and the expected return on book equity.[25] It follows, therefore, that the M/B ratio likewise is a function of numerous variables in addition to the historical or expected Return on Common Equity.

Q23. As a practical matter, would a rational investor invest in utility stocks if they believed that utility commissions would set rates in an effort to move the M/B ratio toward unity?

A23. No. While Staff Witness Parcell states that his CEM "recommendation is not

---

[25] *See* for example, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366. Please note that Dr. Morin cites several academic articles that address the various factors that affect the Market-to-Book ratio for utilities. In addition, the notion that book values should be set at a value approaching unity by regulatory commissions has been refuted for many years. As noted by Stewart Meyers in 1972: "In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book." Stewart C. Meyers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 58-97.

designed to result in market-to-book ratios as low as 1.0",[26] he suggests that "maintenance of a financially stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to maintain the utility's financial stability."[27] If, however, an investor purchased a utility stock at the long-term average M/B ratio of approximately 171.00% (*i.e.*, Staff Witness Parcell's proxy group average from 1992-2012 as calculated based on the annual median results for Staff Witness Parcell's proxy group in Exhibit___(DCP-1), Schedule 10), that investor would incur a loss of approximately 35.09% if the M/B ratio fell to 111.00% (*i.e.*, a level that presumably is "a bit higher" than 100.00%).[28] Such a result would certainly impede the ability to attract the capital required to support its operations.

That example points out a substantial shortcoming of Staff Witness Parcell's analysis: while he suggests that the current level of M/B ratios indicates returns that exceed the Cost of Equity, he fails to identify the ratio that would set the required return equal to the realized return. It is not surprising that Staff Witness Parcell has not done so since, as discussed below, there are a number of variables beyond the earned ROE that affect the M/B ratio. Because the data presented by Staff Witness Parcell focuses on only one of those factors (*i.e.*, the earned return on equity), they produce empirical results that are highly inconsistent with market realities.

---

26 Direct Testimony of Staff Witness Parcell, at 24.

27 *Ibid.*

28 Even assuming the 155.00% M/B ratio for Staff Witness Parcell's proxy group in 2012, the loss would be approximately 28.39%. As discussed below, 111.00% reflects a 10.00% factor for dilution and flotation costs.

Q24. How does Staff Witness Parcell reflect the relationship between M/B ratios and the Return on Common Equity in his CEM analysis?

A24. Staff Witness Parcell first compares the historical earned returns on book equity with historical M/B ratios for our respective proxy groups,[29] and concludes that historical earned returns on book equity support M/B ratios from 160.00% to 180.00%.[30] Staff Witness Parcell then considers the historical earned returns on book equity and concurrent M/B ratios for the S&P 500 (for the years 1992 through 2012), together with a comparison of the risk levels for both the S&P 500 and our respective proxy groups. Based on those observations, Staff Witness Parcell concludes that the "competitive sector" (*i.e.,* the S&P 500) is more risky than the proxy companies, and has historical earned returns and M/B ratios that exceed those of the proxy groups.[31]

Q25. Does Staff Witness Parcell consider variables other than the earned return on equity in arriving at his Cost of Equity estimate?

A25. No. Although Staff Witness Parcell considers differences in the level of risk between the proxy group and the S&P 500 to arrive at his conclusion that unregulated companies are relatively more risky than regulated companies, that point is not in dispute. Beyond that, Staff Witness Parcell does not consider any other variables that may affect M/B ratios.

Q26. What are the implications of his failure to do so?

A26. By failing to consider other variables, Staff Witness Parcell's CEM analysis assumes that the only factor that has a "direct relationship" to the M/B ratio is the

29 *See* Direct Testimony of Staff Witness Parcell, at 22.
30 *Ibid.*
31 *Ibid.,* at 23.

earned ROE.[32] If that were the case, the relationship between earned returns and the M/B ratio could be estimated via linear regression analysis. Using the data contained in Staff Witness Parcell's Exhibit___(DCP-1), Schedule 10, I developed a simple linear regression, in which the M/B ratio is the dependent variable, and the ROCE (the "Return on Average Common Equity" presented in Page 1 of that Schedule) is the sole explanatory variable.[33]

Q27. Please briefly describe how your regression analysis is structured.

A27. My first analysis is focused on the average equity returns and M/B ratios presented in Staff Witness Parcell's Exhibit___(DCP-1), Schedule 10.[34] For Staff Witness Parcell's proxy group, I performed a linear regression analysis in which the M/B ratio was modeled as a function of the ROCE. In that case, the regression equation was statistically significant at the 95.00% confidence level. I then used the regression coefficients to determine the ROCE that would be associated with various levels of M/B ratios.

Q28. On what basis did you select the range of M/B ratios?

A28. While Staff Witness Parcell did not specify what he would consider to be the optimal ratio, he did note that an objective of setting the ROE would be to "attract new equity capital without dilution."[35] Since dilution would be a function of both equity issuance costs and the market pressure associated with new shares, the M/B ratio should exceed 100.00% in an amount sufficient to reflect those costs. Assuming

32 *Ibid.*, at 24.
33 *See* Schedule (RBH-R)-10.
34 Please note that because Staff Witness Parcell did not provide projected Market-to-Book ratios, my analysis necessarily was based on historical data.
35 Direct Testimony of Staff Witness Parcell, at 21.

a dilution cost of 10.00% (reflecting both direct costs and market pressure) would be quite reasonable, if not conservative.[36] Based on a 10.00% dilution rate, the adjusted M/B ratio would be approximately 111.00%.[37]

Using the regression coefficients (*see* Schedule (RBH-R)-10), I then calculated the ROE that would correspond to an M/B ratio of 111.00% for the respective proxy groups. In the case of Staff Witness Parcell's proxy group, the resulting ROE is approximately 4.38%; the resulting ROE for my proxy group is approximately 4.61%. Those results are below the current A-rated utility bond yield (*see* Chart 10 in my response to DPA Witness Woolridge) and as such, have no relevance to the determination of the Company's Cost of Equity.

Q29. Did you perform similar analyses to determine the M/B ratio that would be associated with the low end of your recommended ROE range?

A29. Yes, I did. Based on our respective proxy groups, I calculated the M/B ratios that correspond to an ROE of 10.00%. Using the data in Exhibit___(DCP-1), Schedule 10, I then calculated the percentile in which the implied M/B ratio fell within the historical observations (I performed the same calculation for both my and Staff Witness Parcell's proxy groups). I performed the same set of calculations assuming the Company's proposed 10.25% ROE recommendation. The results of those analyses are presented in Table 2 (below).

---

36 *See* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 323-327.

37 Equals (1/(1-dilution costs).

Table 2: Implied Market-to-Book Ratios at 10.00% and 10.25% ROE[38]

Implied Market-Book Ratio	*Implied ROE (Parcell Proxy Group)*	*Implied ROE (Hevert Proxy Group)*
162% (41st)	10.00%	---
163% (36th)	---	10.00%
165% (42nd)	10.25%	---
165% (37th)	---	10.25%

Q30. What are your conclusions regarding Staff Witness Parcell's Comparable Earnings Method?

A30. My principal conclusion is that while the high end of Staff Witness Parcell's CEM results (*i.e.*, 10.00%) overlaps with the low end of my recommended range, the low end of Staff Witness Parcell's CEM results (*i.e.*, 9.50%) under-estimates the Company's Cost of Equity. Based on the data presented in Exhibit___(DCP-1), Schedule 10, the lower end of my recommended range (*i.e.*, 10.00% to 10.75%) is a more reasonable estimate.

IV. <u>Response to Direct Testimony of DPA Witness Woolridge</u>

Q31. Please provide a brief summary of DPA Witness Woolridge's testimony and ROE recommendation.

A31. DPA Witness Woolridge recommends an ROE of 8.50%, which represents the upper end of his DCF and CAPM results.[39] In developing his ROE estimates, DPA Witness Woolridge relies primarily on the Constant Growth DCF model. In applying his DCF analysis, DPA Witness Woolridge reflects a variety of growth measures,

38 *See* Schedule (RBH-R)-10.
39 *See* Direct Testimony of DPA Witness Woolridge, at 38.

including growth in dividends, book value, and earnings. While DPA Witness Woolridge gives "greater weight" to the DCF model, he suggests that his 8.50% recommendation is supported by currently low interest rates and low "expected returns on financial assets."[40] Finally, DPA Witness Woolridge relies on the Company's originally proposed capital structure consisting of 48.78% common equity and 51.22% long-term debt.[41]

Q32. What are the principal areas of disagreement between you and DPA Witness Woolridge?

A32. There are several areas in which DPA Witness Woolridge and I disagree. In general, those areas include: (1) the growth rates to be applied in the Constant Growth DCF model; (2); the application of the Multi-Stage DCF model; (3) the application of the Quarterly Growth DCF model; (4) the application of the CAPM; (5) the reasonableness of the Bond Yield Plus Risk Premium analysis; (6) the effect of current capital market conditions on the Company's ROE; and (7) the relevance of certain business risks that affect the Company's ROE, such as flotation costs, the Company's relatively small size, and the lack of revenue stabilization mechanisms employed by Delmarva.

---

40 *Ibid.*

41 Exhibit JRW-1 and Exhibit JRW-5. DPA Witness Woolridge notes on page 11 of his direct testimony that he relied on the Company's updated capital structure consisting of 49.22% common equity and 50.78% long-term debt (*See* Schedule (KMM-S)-1). In his response to Delmarva Data Request #2 to the Attorney General's Office, however, DPA Witness Woolridge states that the capital structure included in his direct testimony is incorrect.

Application of Constant Growth DCF Analysis

Q33. What differences exist between DPA Witness Woolridge's and your application of the Constant Growth DCF model?

A33. As a preliminary matter, I strongly disagree with DPA Witness Woolridge that a mean DCF result of 8.60% has any analytical value in determining the Company's Cost of Equity. In fact, there has not been an authorized ROE in any jurisdiction as low as 8.60% for a natural gas utility since at least 1980.[42] It is clear that in large measure, DPA Witness Woolridge's results are downwardly biased by his application of the DCF approach, in particular the growth rate estimates applied in that model.

Q34. What growth rates does DPA Witness Woolridge include in his Constant Growth DCF analysis?

A34. DPA Witness Woolridge arrives at his growth rates based on a review of a number of data points, including: historical and projected DPS, BVPS, and EPS growth rates as reported by Value Line; consensus EPS growth rate projections from First Call, Reuters, and Zacks; and an estimate of "sustainable growth." DPA Witness Woolridge indicates that he has given more weight to projected growth rates in arriving at his 4.75% growth rate estimate.[43]

---

[42] I note that DPA Witness Woolridge's DCF result and ROE recommendation are over 20 and 30 basis points lower than the lowest authorized ROE of 8.83% over that time period, respectively.

[43] Direct Testimony of DPA Witness Woolridge, at 29.

Table 3: Summary of DPA Witness Woolridge's Growth Rate Estimates[44]

	Gas Proxy Group
Value Line Historical Growth Rates (DPS, BVPS, EPS)	4.30%
Value Line Projected Growth Rates (DPS, BVPS, EPS)	4.40%
Sustainable Growth	4.40%
Analyst Projected EPS Growth Rates (excl. Value Line)	5.00%
Average of Historic and Projected Growth Rates	4.50%
Average of Sustainable and Projected Growth Rates	4.60%
Woolridge DCF Growth Rate	*4.75%*

As to the use of projected earnings growth rates, DPA Witness Woolridge asserts that there is a systemic and upward bias in those estimates and as such, "the DCF growth rate needs to be adjusted downward from the projected EPS growth rate."[45] DPA Witness Woolridge also discusses at length the weaknesses he perceives in relying solely on forecasted EPS growth rates for the purpose of the DCF model. Despite those concerns, DPA Witness Woolridge relies on projected EPS growth rates from First Call, Reuters, and Zacks, as well as projected DPS, BVPS, and EPS growth rates from Value Line.

Q35. Does DPA Witness Woolridge express any specific concerns with your use of analysts' earnings growth projections in your DCF models?

A35. DPA Witness Woolridge's argument that analysts' earnings growth estimates are "overly optimistic and upwardly biased," and that relying on such estimates

---

44 Exhibit JRW-10, at 6.

45 Direct Testimony of DPA Witness Woolridge, at 28.

is a methodological error, is neither accurate nor persuasive. It is important to note, however, that while DPA Witness Woolridge's assertion is based on his observations with respect to the broad market, he has provided no evidence that any of the growth rates used in my DCF analysis is the result of a consistent and pervasive bias on the part of the analysts providing those projections.

Q36. What is your response to DPA Witness Woolridge in that regard?

A36. In light of restrictions imposed by the October 2003 Global Research Analyst Settlement, it is unclear how or why utility analysts' estimates would continue to be biased. That settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows", and required the settling financial institutions to fund independent third-party research.[46] To that point, a 2010 article in Financial Analyst Journal found that analyst forecast bias has declined significantly or disappeared entirely since the final judgment was issued in October 2003:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that of related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[47]

---

[46] The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

[47] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at 105.

Based on a review of disclosures contained in recent analyst reports for certain of the proxy companies, it is apparent that the standard industry practice is to avoid conflicts of interest by ensuring that compensation is not, either directly or indirectly, linked to the opinions contained in those reports. In fact, some reports go so far as to demonstrate the specific factors that determine compensation, including the accuracy of earnings estimates, which creates a disincentive for either over- or under-estimating earnings.[48]

Q37. Is the use of analysts' earnings growth projections in the DCF model supported by literature?

A37. Yes. Regardless of whether DPA Witness Woolridge believes that analysts' growth rate projections are systemically biased, the relevant analytical question is whether investors rely on those estimates in making their investment decisions. There have been many published articles that specifically support the use of analysts' earnings growth projections in the DCF model in general, as well as for a method of calculating the expected MRP in particular. A 1986 article entitled *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return* by Dr. Robert Harris, for example, demonstrated that financial analysts' earnings forecasts (referred to in the article as "FAF") in a Constant Growth DCF formula are an appropriate method of calculating the expected MRP.[49] In that regard, Dr. Harris noted that:

> …a growing body of knowledge shows that analysts' *earnings* forecasts are indeed reflected in stock prices. Such studies typically

---

48 *See* for example, BMO Capital Markets, *Viewpoint*, September 18, 2012, at 8.

49 *See* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986 at 66.

> employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[50]

Dr. Harris further noted that:

> Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[51]

Similarly, in an article entitled *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts,* Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts."[52] In addition to other findings, Harris and Marston reported that,

> ...in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[53]

Here again, the finding was clear: analysts' earnings forecasts are highly related to stock price valuations and, therefore, are appropriate inputs to stock valuation and ROE estimation models.[54]

---

50 *Ibid.*, at 59. Emphasis added. As noted in my Direct Testimony, Zacks and First Call, the sources of earnings growth projections that I use in addition to Value Line, are consensus forecasts.

51 *Ibid.*, at 60.

52 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992.

53 *Ibid.*, at 63.

54 I also note that research cited by DPA Witness Woolridge supports the position that earnings are the proper measure of growth for the DCF model. In that regard, page 51 of DPA Witness Woolridge's testimony refers to an article by Bradford Cornell that states, in part, that "[t]he long –run performance of equity investments is fundamentally linked to growth in earnings." Since the DCF model is based on observed prices, and given that the model assumes that earnings and dividends will grow at the same constant rate in perpetuity the observation that stock prices are "fundamentally linked to growth in earnings" further supports the use of EPS growth rates in the Constant Growth DCF model.

Q38. Please summarize DPA Witness Woolridge's analyses regarding the use of consensus earnings growth rate projections.

A38. DPA Witness Woolridge compares the actual three-to-five-year EPS growth rates and forecasted EPS growth rates for all the companies covered by I/B/E/S.[55] His results indicate that on average, for all industries covered by I/B/E/S, analysts' projected EPS growth rates have exceeded historical EPS growth. As DPA Witness Woolridge notes, however, there were "negative forecast errors" (*i.e.*, analysts' EPS forecasts understated actual growth in EPS) following the recessions of 1991 and 2001.[56] DPA Witness Woolridge performs a similar analysis using I/B/E/S-covered electric and gas utilities. DPA Witness Woolridge draws his conclusions regarding the accuracy of analysts' long-term earnings growth rates based on the forecast error experienced across all industries covered by I/B/E/S, as well as the I/B/E/S-covered utilities, suggesting that the proxy companies likewise are susceptible to persistent and biased forecast errors.[57]

Q39. Do you agree with DPA Witness Woolridge's assertion in that regard?

A39. No, I do not. While DPA Witness Woolridge suggests that "long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased,"[58] and that growth rates for utilities display a similarly upward bias,[59] he has not analyzed the companies that are included in my proxy group. In fact, as discussed below, the results of an analysis of the companies in my proxy

55 Institutional Brokerage Estimate Service (I/B/E/S).
56 *See* Direct Testimony of DPA Witness Woolridge, Appendix B, at B-8.
57 *Ibid.*, at B-10 – B-11.
58 Direct Testimony of DPA Witness Woolridge, at 27.
59 *See* Direct Testimony of DPA Witness Woolridge, Appendix B, at B-10 – B-11.

group (which contains all of the companies in DPA Witness Woolridge's proxy group) indicates that analysts tend to provide fairly accurate forecasts of earnings growth.

Q40. Please describe the analysis you performed to address DPA Witness Woolridge's assumption that the proxy companies' earnings growth estimates are biased.

A40. In order to assess whether analyst growth rates are excessively optimistic, I examined the extent to which the consensus forecast earnings either under- or over-estimated annual earnings from 2002 through 2012 for the proxy companies. Based on data provided by Bloomberg, Schedule (RBH-R)-11 demonstrates that the average annual difference between actual and projected earnings (that is, the "Earnings Surprise") was negative 0.12%. That is, actual earnings were essentially equal to projected earnings for my proxy group. Analysts actually underestimated earnings for seven of the nine proxy companies over the eleven year period. Similarly, analysts underestimated earnings for the proxy group in six of the eleven years, suggesting at the margin, a tendency to under-estimate earnings. In fact, of the 99 observations, analysts only over-estimated earnings 34 times. Given that the average Earnings Surprise (negative 0.12%) is essentially zero, it appears that, on average, analysts tend to provide accurate forecasts of earnings for the proxy group. I understand that annual earnings estimates are not the long-term growth rate projections used in the Constant Growth DCF model. However, if DPA Witness Woolridge is correct and earnings projections are overly optimistic it would stand to reason that such a bias would exist in annual forecasts as well. As demonstrated above, that has not been the case. If anything, companies covering the proxy group companies are somewhat conservative.

Q41. Do you agree with DPA Witness Woolridge's assertion that dividends or book value are appropriate measures of expected growth for the Constant Growth DCF model?

A41. No, I do not. As discussed in my response to Staff Witness Parcell, it is important to realize that earnings growth enables both dividend and book value growth. That is, book value can increase over time only through the addition of retained earnings, or with the issuance of new equity. Both of those factors are derivative of earnings: retained earnings increases with the amount of earnings not distributed as dividends; and the price at which new equity is issued is a function of the EPS and the then-current P/E ratio. Similarly, as noted in my Direct Testimony, earnings are the fundamental driver of a company's ability to pay dividends. Corporate decisions to manage the dividend payout ratio for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can influence dividend growth rates in near-term periods in a manner that is disproportionate to earnings growth.

In addition, as discussed in my response to Staff Witness Parcell, Value Line is the only service relied on by DPA Witness Woolridge that provides DPS, BVPS, or retention growth projections. To the extent that the earnings projections services such as Zacks and First Call represent consensus estimates, the results are less likely to be biased in one direction or another as a result of an individual analyst.

Finally, as shown in Schedule (RBH-R)-12, I recreated DPA Witness Woolridge's DCF analysis, relying on each of the average projected analyst growth estimates and the dividend yield in Exhibit JRW-10. The results based on the DPS and BVPS growth rates are 7.57% and 8.40%, which are both significantly below the lowest authorized return in at least 30 years. The average of the DCF results based on the EPS growth rates is 9.01%. While I do not believe that 9.01% is a reasonable estimate of the Delmarva's ROE, it is approximately 50 basis points higher than DPA Witness Woolridge's recommendation.

Q42. Do you have any further observations regarding the growth rates used in DPA Witness Woolridge's DCF analysis?

A42. Yes. First, it is interesting to note that in his "Building Blocks" approach to developing the equity risk premium, DPA Witness Woolridge has established an expected long-run nominal growth rate of 5.40%.[60] As DPA Witness Woolridge notes, it is not uncommon for analysts to use an estimate of long-term economic growth as a proxy for the long-term growth of the firm.[61] Given DPA Witness Woolridge's expected dividend yield of 3.84% for his proxy group, the expected DCF result would be approximately 9.24%.[62] While that result is still below a reasonable estimate of the Company's Cost of Equity, it is approximately 65 basis points above DPA Witness Woolridge's DCF result, and 75 basis points higher than his recommended 8.50% ROE. Looking to DPA Witness Woolridge's Exhibit JRW-14, page 2 of 3, the average growth rate of 6.36% would produce a DCF estimate of 10.20%, which is only five basis points below the Company's proposed 10.25% ROE.

---

60 *See* Direct Testimony of DPA Witness Woolridge, Appendix C, at C-2 – C-3. 5.40% equals the sum of the Expected Inflation amount of 2.75% and the Real Earnings Growth Rate of 2.65%.

61 *Ibid.*, at 51.

62 *See* Exhibit JRW-10, at 1 of 6. The estimated dividend yields include the one-half year convention for calculating the expected dividend yield.

Q43. Those differences aside, do you believe DPA Witness Woolridge's DCF analysis produces a reasonable estimate of Delmarva's Cost of Equity?

A43. No, I do not. The results of any given model must be interpreted in the context of current capital market conditions. DPA Witness Woolridge's DCF analysis suggests an ROE estimate that is 140 basis points below the Company's currently authorized return and over 20 basis points below the lowest authorized return since at least 1980. As discussed in my response to Staff Witness Parcell, current capital market conditions cannot account for such a significant deviation.

Application of Multi-Stage DCF Analysis

Q44. What is your response to DPA Witness Woolridge's assertion that the long-term growth rate in your Multi-Stage DCF analysis is overstated and inconsistent with historical and projected measures of GDP?[63]

A44. The use of long-term GDP growth in the terminal period is consistent with financial literature. For example, Dr. Roger Morin writes "[i]t is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy."[64] In a similar vein, Morningstar describes a three-stage DCF approach (generally consistent with the model included in my Direct Testimony) in which the final stage assumes that long-run growth moves toward that of the overall economy.[65] Morningstar describes an approach to calculating the long-term growth estimate that is similar to that which is included in my Multi-Stage DCF model. Morningstar's method

---

[63] *See* Direct Testimony of DPA Witness Woolridge, at 47-48.

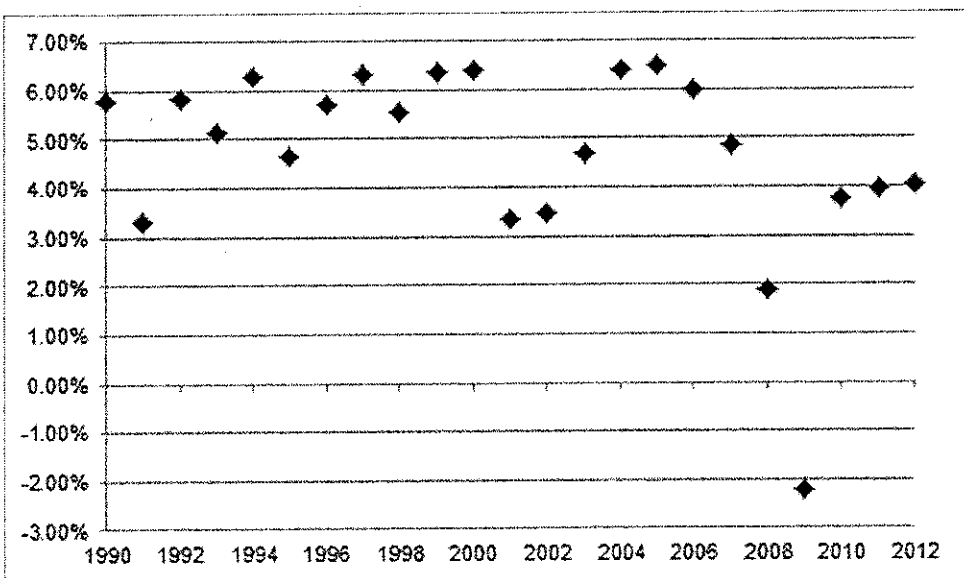
[64] Roger A. Morin, New Regulatory Finance, Public Utilities Report, Inc., 2006, at 308.

[65] *See* Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 51.

combines historical average real GDP growth rate with a measure of inflation calculated using the TIPS spread.[66] Consequently, my approach is quite consistent with financial theory and practice.

DPA Witness Woolridge suggests that "nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy."[67] He supports this claim by reviewing the average nominal GDP over periods of 10 to 50 years.[68] As illustrated on Chart 6 (below), however, the annual nominal growth rate in GDP since 1990 (*i.e.*, in "recent decades") remained relatively stable, but for the period 2008 to 2012 which included the recent recession.

Chart 6: Annual Nominal GDP Growth Rates



In fact, over that period, annual nominal GDP growth rates of greater than

66 *Ibid.*, at 52. I note that the long-term growth rate in my Multi-Stage DCF model (*see* Schedule (RBH-R)-4) equals 5.70%. Implied Expected Nominal GDP = ((1 + Historical Real GDP Growth) x (1 + Implied Forward Inflation)) - 1 or 5.70% = ((1 + 3.22%) x (1 + 2.39%)) - 1.

67 Direct Testimony of DPA Witness Woolridge, at 47.

68 I note that DPA Witness Woolridge's calculation of the 30-year average noted on page 47 of his direct testimony, which was noted as 5.10%, is actually 5.40%.

5.00% (the high end of DPA Witness Woolridge's suggested range) occurred in 12 of the 23 years. Growth rates of at least 5.70% occurred in 10 of the 23 years.

Comparing historical nominal growth rates in GDP since 1960, however, will invariably be affected by periods of differing inflation rates. For example, the real GDP growth rates in 1980 and 1991 were nearly identical at negative 0.28% and negative 0.23%, respectively; on a nominal basis, however, the growth rates were 8.82% and 3.30%. Given that inflation was significantly higher in the 1970's than it currently is, it is not surprising that nominal GDP rates are lower when viewed within the context of shorter term averages (*i.e.*, over the last ten or twenty years as DPA Witness Woolridge has done).

In addition, as shown in Table 4 (below), the recent economic downturn has had a significant effect on the real GDP growth rate calculated over shorter time periods.

Table 4: Average Real GDP Growth Rates

Average Length	*As of 2012*	*As of 2007*
10-Year Average	1.67%	2.99%
20-Year Average	2.53%	3.01%
30-Year Average	2.86%	3.06%
40-Year Average	2.74%	3.09%
50-Year Average	3.04%	3.33%

In fact, immediately prior to the beginning of the recession the difference between the varying average growth rates was minimal. Since (for the purpose of the Multi-Stage DCF model) the long-term growth rate is applied *beginning* ten years in the future, it would be inappropriate to give undue weight to short-term trends in the time series, as DPA Witness Woolridge appears to have done. As to the inflation portion of the expected nominal growth rate, DPA Witness Woolridge does not appear to disagree with my expected inflation rate of 2.45%, as he noted that the current inflation rate is "in the 2% to 3% range."[69] Lastly, I note that in his schedules, DPA Witness Woolridge provides the average growth rates (since 1960) for nominal GDP, the S&P 500 stock prices, the S&P 500 EPS and the S&P 500 DPS.[70] The average of those measures is 6.36%,[71] which is 61 basis points above the long-term growth rate estimate of 5.75% included in my Direct Testimony and 66 basis points above the long-term growth rate estimate in Schedule (RBH-R)-4. It also is interesting to note that the 6.36% average growth rate noted above is 13 basis points above the 6.23% long-term nominal GDP growth rate reported by the Bureau of Economic Analysis.

Lastly (as discussed above), DPA Witness Woolridge's long-term nominal growth range of 4.00% to 5.00% is inconsistent with the implied long-term nominal growth rate of 5.40% assumed in his "Building Blocks" approach to developing the Equity Risk Premium. It is apparent, therefore, that my expected long-term growth rate is consistent, if not conservative, relative to the historical and expected growth rates cited by DPA Witness Woolridge.

---

69 Direct Testimony of DPA Witness Woolridge, at 51.

70 *See* Exhibit JRW-14, Page 2 of 3.

71 *See* Direct Testimony of DPA Witness Woolridge, at 50 and Exhibit JRW-14.

Application of Quarterly Growth DCF Analysis

Q45. Do you agree with DPA Witness Woolridge that the Quarterly Growth DCF model does not accurately estimate Delmarva's ROE?

A45. No, I do not. DPA Witness Woolridge suggests that the results of the Quarterly Growth DCF model are overstated relative to the Constant Growth DCF model because (1) the model does not calculate the dividend yield as the expected dividend for the next quarter multiplied by four, and (2) the reinvestment of quarterly dividends creates its own compounding which is "outside of the dividend payments of the issuing company."[72] DPA Witness Woolridge further suggests that my application of the model overstates Delmarva's Cost of Equity because the approach "duplicate[s] this compounding process, thereby inflating the return to the investor."[73]

Q46. What is your response to DPA Witness Woolridge on that point?

A46. As noted in my Direct Testimony, the purpose of the Quarterly DCF model is to recognize that dividends are paid on a quarterly basis, and to recognize the time value associated with the timing of those payments. My Direct Testimony made clear that the intent is to reflect "the time value of money associated with quarterly compounding," the effects of which are expected and required by investors.[74] In that regard, the Constant Growth DCF model also assumes that cash flows received by investors are reinvested. The difference is that the Quarterly DCF model explicitly reflects the fact that those dividends are paid on a quarterly, not an annual, basis. Both models, however, assume that investors have the ability to reinvest those cash

---

72 *Ibid.*, at 41-42.
73 *Ibid.*, at 42.
74 Direct Testimony of Robert B. Hevert, at 10-11.

flows when received, and that the funds are reinvested at the Cost of Equity. That is the fundamental premise of any Internal Rate of Return calculation which, of course, is the premise of the Discounted Cash Flow approach. To that point, Dr. Roger Morin notes that the reinvestment of dividends is not unique to the Quarterly Growth model. In fact:

> All DCF models share the common assumption that cash dividends are reinvested at the cost of equity. The annual DCF model also accounts for the periodic reinvestment of dividends as they are received. The reinvestment of cash flows received, or compounding, is the hallmark of all DCF models. If you remove the return component due to the reinvestment of dividends as received, the DCF model is reduced to a simple interest calculation rather than a compound interest calculation. This contradicts the very essence of DCF calculations which are predicated on compound interest, that is, the earning of interest on interest. The quarterly DCF model contains the same dividend reinvestment assumptions as does the annual DCF model.[75]

In that regard, the Quarterly DCF model is not unlike the calculation of the Yield to Maturity (YTM) of Treasury securities. Treasury bonds pay interest on a semi-annual basis, and the YTM assumes that those interest payments are reinvested, twice each year, at the calculated yield. That is, the YTM calculation does not assume that even though interest is paid semiannually, those payments are reinvested only annually.

Application of the Capital Asset Pricing Model

Q47. Please describe DPA Witness Woolridge's CAPM results and how the results were applied in determining the Cost of Equity for Delmarva.

A47. DPA Witness Woolridge's CAPM analysis produces an estimated Cost of Equity of 7.30%. While DPA Witness Woolridge places greater weight on his DCF

[75] Roger A. Morin, <u>New Regulatory Finance</u>, Public Utilities Reports, Inc. (2006), at 354-355.

analysis, he nonetheless relies on his CAPM analysis in determining what he considers to be the appropriate range for the Company's estimated Cost of Equity.[76] As with DPA Witness Woolridge's DCF results, I strongly disagree that a CAPM result of 7.30%, which is more than 150 basis points lower than any authorized ROE for a natural gas utility since at least 1980, has any analytical value in determining the Company's ROE. As discussed below, DPA Witness Woolridge's 7.30% CAPM estimate is primarily the result of his estimated Market Risk Premium.

Q48. Please describe how DPA Witness Woolridge's calculated his estimate of the Market Risk Premium.

A48. DPA Witness Woolridge reviewed a series of studies that calculated the MRP using different methodologies; he also considered the results of his "Building Blocks" approach. Based on those reviews, DPA Witness Woolridge concluded that the MRP ranges from 4.50% to 5.50% and within that range, the midpoint of 5.00% is reasonable. DPA Witness Woolridge then cites the results of three surveys, and suggests that his results are consistent with the views of Chief Financial Officers (CFO), professional forecasters, and financial analysts.

Q49. What is your response to DPA Witness Woolridge on those points?

A49. First, by referring to the *Duke CFO Survey* by Professors Graham and Harvey which, he suggests, points to an expected MRP of 4.50%, DPA Witness Woolridge concludes that his estimated MRP is consistent with those used by CFOs.[77] The survey also reports a standard deviation of 7.50% for its sample of estimates of the expected market return. My estimates of the expected market return are well within

[76] *See* Direct Testimony of DPA Witness Woolridge at 38.
[77] *Ibid.*, at 36.

two standard deviations of the expected return noted in the survey. That is, even based on the *Duke CFO Survey* results, my estimate of the expected market return falls within a 95.00% confidence interval.

In addition to certain measures of expected market returns, recent versions of the survey also asked respondents to provide their Weighted Average Cost of Capital (WACC), and Hurdle Rates.[78] Those two metrics are measures of the required, as opposed to the expected return. It also is important to note that the WACC includes both debt and equity; to the extent there is any debt in the capital structure, the WACC will be less than the Cost of Equity. In that regard, the mean WACC reported in the most recent survey for which those particular estimates were included, was 9.30%, and the mean Hurdle Rate was 13.50%.[79] Those rates, which are well in excess of the reported expected return, are more appropriate measures of the returns actually required in the market and are similar to the market returns of 13.07% and 12.84% in my updated calculation of the MRP.[80]

Second, by referring to a survey by the Federal Reserve Bank of Philadelphia that reported in an *ex-ante* MRP of 2.30%, DPA Witness Woolridge suggests that his estimated MRP is consistent with MRPs used by professional forecasters.[81] On reviewing that survey, I note that it does not specify whether the expected returns for the S&P 500 represent *total* returns or only capital appreciation. Specifically, the survey question states: "What do you expect to be the annual average [stock return]

---

78 The survey has not provided the results of these questions since June 2012.

79 *See, The Duke CFO Business Outlook Survey*, June 2012 Results, Table 10. The prevailing MRP based on the June 2012 survey was 4.50% with a Treasury bond yield of 1.80% and an expected return of 6.30%.

80 *See* Schedule (RBH-R)-5.

81 *See* Direct Testimony of DPA Witness Woolridge at 36-37.

over the next ten years for the S&P 500?"[82] To the extent the Philadelphia Fed survey results include only capital gains and not dividends, the survey understates the actual total return that investors expect, which, in turn, suggests that it is not appropriate to rely on that survey to estimate the market risk premium because the long-term growth rate for the S&P 500 might be understated. Further, the Survey of Professional Forecasters for the first quarter of 2013 considered the responses of 46 economists and financial forecasters; however, only 22 survey participants responded to the question regarding the expected return for the S&P 500 over the next ten years.[83] Similarly, only 20 responded to the expected return on ten-year Treasury bonds.

Lastly, DPA Witness Woolridge cites a study by Pablo Fernandez titled "Market Risk Premium used in 82 countries in 2012: a survey with 7,192 answers", which found that the median MRP "employed by U.S. analysts and companies was 5.0% and 5.5%, respectively."[84] That study also discusses how the required equity risk premium is commonly calculated using a Constant Growth DCF approach. It states:

> [t]he implied equity premium is the implicit required equity premium used in the valuation of a stock (or market index) that matches the current market price. The most widely used model to calculate the [implied equity premium] is the dividend discount model: the current price (P_0) is the present value of expected dividends discounted at the required rate of return (Ke). If d_1 is the dividend per share expected to be received in year 1, and g the expected long-term growth rate in dividends per share:
>
> $P_0 = d_1 / (Ke - g)$, which implies:

[82] Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter of 2011, at 4.
[83] *Ibid.*, at 17.
[84] Direct Testimony of DPA Witness Woolridge at 37.

$$[\text{implied equity premium}] = d_1/P_0 + g - R_f$$ [85]

As explained in my Direct Testimony, I calculated the *ex-ante* MRP in a similar manner using a market capitalization weighted Constant Growth DCF estimate of the individual companies in the S&P 500 Index. Therefore, the Fernandez study supports the method I used to estimate the MRP in my testimony.

Q50. Did DPA Witness Woolridge's express any concerns regarding your CAPM analysis?

A50. DPA Witness Woolridge's primary disagreement with my CAPM analysis involves the Market Risk Premium component of the model. As to my use of expected market returns, DPA Witness Woolridge states that the result is "inflated due to errors and bias in [my] study."[86] DPA Witness Woolridge also calculates the long-term EPS growth rates for the S&P 500 of 10.44% and 10.76% based on the data from Bloomberg and Capital IQ, respectively,[87] and notes that they "are not consistent with historic as well as projected economic and earnings growth."[88]

Q51. Turning to DPA Witness Woolridge's position that the EPS growth rates used to develop your total return on the market estimate are too high, did you consider where your estimates fall within the range of historical observations?

A51. Because DPA Witness Woolridge concludes that the EPS growth rates I relied on to calculate the market return estimates used in my analyses are "overstated" relative to historical levels, it is instructive to understand how often various ranges of

85 Pablo Fernandez, Javier Aguirreamalloa and Luis Corres, *Market Risk Premium used in 82 countries in 2012: a survey with 7,192 answers*, IESE Business School, University of Navarra, at 13.

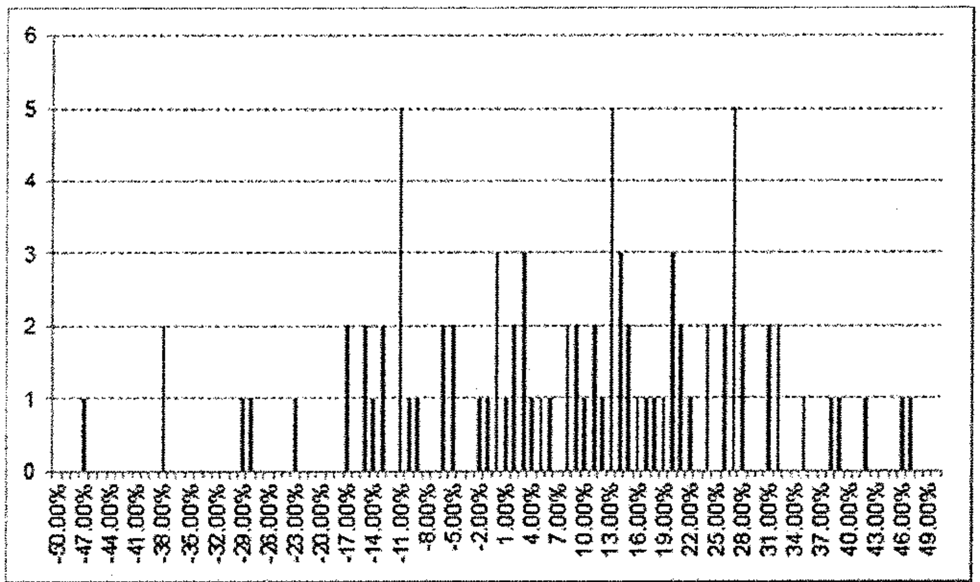
86 Direct Testimony of DPA Witness Woolridge, at 52.

87 *See* Schedule (RBH)-5.

88 Direct Testimony of DPA Witness Woolridge at 49.

growth rates actually have occurred over the 1926 to 2012 period. To perform that analysis, I gathered the annual capital appreciation return on Large Company Stocks reported by Morningstar, produced a histogram of those observations, and calculated the probability that a given capital appreciation return estimate would be observed. The results of that analysis, which are presented in Chart 7, demonstrate that capital appreciation rates of 10.00% to 11.00% and higher actually occurred quite often.

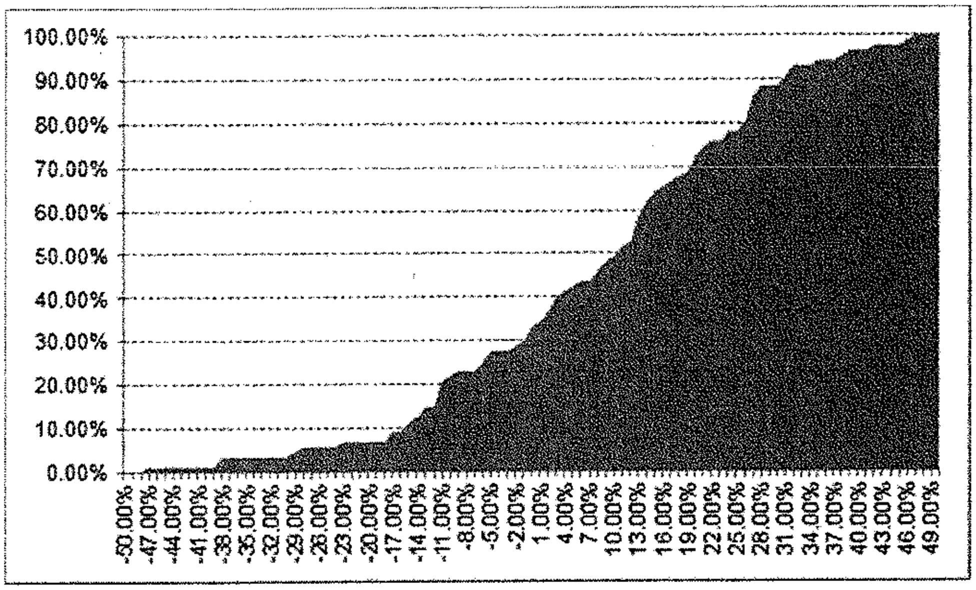
Chart 7: Frequency Distribution of Observed Capital Appreciation Rates, 1926 - 2012[89]



In fact, the 10.44% and 10.76% estimates, which DPA Witness Woolridge asserts are "overstated" by historical standards represent the 50^{th} percentile of the actual capital appreciation rates observed from 1926 to 2012, as shown in Chart 8 (below).

89 *See* Morningstar, Inc., 2012 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 186-187.

Chart 8: Cumulative Probability of Capital Appreciation Rates



Q52. Do you have any concerns with DPA Witness Woolridge's update to your Sharpe Ratio?

A52. DPA Witness Woolridge misapplies the Sharpe Ratio approach (also contained in my Direct Testimony) in concluding that the Market Risk Premium has decreased significantly since the filing of my Direct Testimony. In that regard, DPA Witness Woolridge concludes that the Market Risk Premium (based on the Sharpe Ratio) has fallen by nearly 300 basis points since the filing of my Direct Testimony, from 7.53% to 4.55%.[90] As described in my Direct Testimony, however, the expected Market Risk Premium is calculated by applying the historical Sharpe ratio (*i.e.*, the ratio of the historical Market Risk Premium and historical market volatility) to expected market volatility. Expected market volatility, as presented in my Direct Testimony, can be measured by the three-month volatility index (the VXV), together

---

[90] *See* Direct Testimony of DPA Witness Woolridge, Exhibit JRW-15, at 2.

with futures prices on the one-month volatility index (the VIX).[91] DPA Witness Woolridge, on the other hand, has applied the Sharpe Ratio to the one-month volatility index (*i.e.*, the VIX), not to the longer-term expected market volatility as measured by the VXV and VIX futures.

The Chicago Board of Options Exchange's (CBOE), which is the same exchange on which the VIX and VXV are traded, also publishes the "Term Structure of Volatility", which provides measures of expected volatility through December, 2015. There, the expected level of the VIX is 23.31.[92] As shown in Schedule (RBH-R)-5, when applied to that longer-term measure of expected volatility, the updated Sharpe Ratio approach produces an expected Market Risk Premium of 7.74%.

While I disagree with DPA Witness Woolridge on those issues, it is important to note that neither of us relies substantially on the CAPM in arriving at our ROE recommendation. Nonetheless, the fact that expected market volatility remains somewhat elevated relative to its long-term average (resulting in a higher expected Market Risk Premium) supports an ROE determination in excess of DPA Witness Woolridge's 8.50% recommendation.

Bond Yield Plus Risk Premium

Q53. Please discuss DPA Witness Woolridge's critique of your Bond Yield Plus Risk Premium analysis?

A53. DPA Witness Woolridge believes that the risk premium derived from the analysis is "excessive" and "is a study of *Commission* behavior, not a study of

---

91 *See* Direct Testimony of Robert B. Hevert, at 29-30.
92 *See* http://www.cboe.com/data/volatilityindexes/volatilityindexes.aspx

investor behavior."[93] DPA Witness Woolridge also believes that the approach is circular because it relies on the outcome of past rate cases in order to determine the current Cost of Equity.[94] Based on the fact that Market-to-Book ratios for gas utilities have generally exceeded 100.00%, DPA Witness Woolridge suggests "that authorized rates of return have been greater than the return that investors require."[95] DPA Witness Woolridge concludes that as a result, the Bond Yield Plus Risk Premium analysis overstates the actual ROE because, in his view, it "tends to perpetuate any past errors, and over time could become entirely disconnected from financial market realities."[96]

Q54. What is your response to DPA Witness Woolridge on those points?

A54. First, M/B ratios above 100.00% do not necessarily suggest that authorized ROEs have been significantly overstated. Reviewing the M/B ratios provided by Staff Witness Parcell in Exhibit___(DCP-1), Schedule 10, page 2, it appears that DPA Witness Woolridge believes that each of the companies in both our proxy groups has enjoyed significantly inflated authorized returns over at least the last 21 years. As discussed in my response to Staff Witness Parcell, however, market value per share is forward-looking while book value per share is an accounting construct based on historical costs. Because the numerator (market value per share) and the denominator (book value per share) are a function of different variables, M/B ratios over 100.00% do not necessarily imply that regulatory commissions have been consistently incorrect with respect to the returns that they have authorized.

93 Direct Testimony of DPA Witness Woolridge, at 55.
94 *Ibid.*
95 *Ibid.*
96 *Ibid.*

Further, as noted in my Direct Testimony, the *Hope* and *Bluefield* guidelines establish that the fair rate of return on equity should be comparable to returns investors expect to earn on other investments of similar risk.[97] Assuming that regulatory commissions appropriately weigh the results of various models, analyses and expert testimony presented before them in order to determine a fair ROE that meets the *Hope* and *Bluefield* standards, authorized ROEs can be used as a proxy for investor return requirements.

DPA Witness Woolridge's criticism of the Bond Yield Plus Risk Premium analysis would, therefore, only be valid if regulatory commissions consistently and significantly over or understated the Cost of Equity. Given that DPA Witness Woolridge does not provide any additional support for this claim beyond his general assertion that M/B ratios for natural gas utilities have been greater than 100.00%, I disagree with his conclusion.

Capital Market Conditions

Q55. What are DPA Witness Woolridge's general observations regarding the current economic environment and its effect on the cost of capital?

A55. DPA Witness Woolridge states that "while the economy continues to face significant problems," following the recent economic crisis, "capital costs have declined to historically low levels."[98] In support of his position, DPA Witness Woolridge points to the significant intervention by the U.S. Federal government in the U.S. credit markets, and decreases in bond yields since the peak of the economic

---

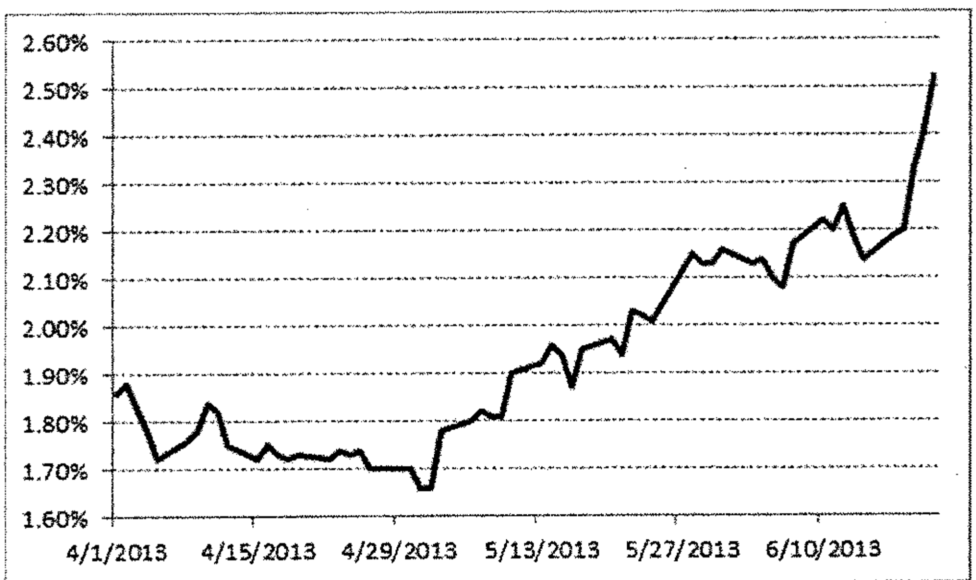
[97] *See* Direct Testimony of Robert B. Hevert, at 4.
[98] Direct Testimony of DPA Witness Woolridge, 7.

crisis. DPA Witness Woolridge further suggests that because six-month average yields on ten-year Treasury bonds and long-term A-rated utility bonds have decreased by approximately 150 basis from June 2011 (*i.e.*, the date of the Company's most recent authorized ROE) to March 2013, capital costs have decreased by the same amount.[99]

Q56. What is your response to DPA Witness Woolridge's general observations?

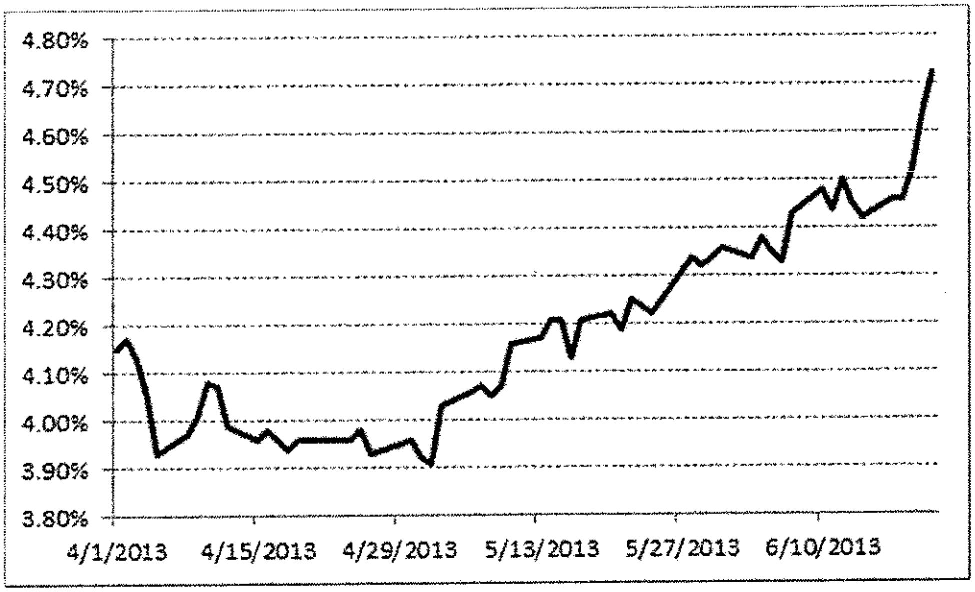
A56. DPA Witness Woolridge focuses his analysis on the low level of Treasury yields and a recent decline in bond yields through March 2013. As illustrated in Charts 9 and 10 (below), in the intervening period, the ten-year Treasury bond yield increased 66 basis points and the yield on Moody's A-rated utility bonds increased 57 basis points (April 1, 2013 through June 21, 2013).

Chart 9: Ten-Year Treasury Bond Yield



[99] *Ibid.*, at 9.

Chart 10: Moody's Utility A-Rated Bond Yield



Furthermore, as discussed in my Direct Testimony, there is an inverse relationship between interest rates and the equity risk premium. While interest rates have fallen somewhat relative to June 2011, the equity risk premium has increased, which suggests that the Cost of Equity has not decreased in tandem with interest rates. As such, DPA Witness Woolridge's review of the decline in ten-year treasury yields and long-term A-rated bond yields provides little insight into the appropriate ROE for Delmarva.

Business Risks

Q57. Did DPA Witness Woolridge address the issue of flotation costs in his direct testimony?

A57. Yes, DPA Witness Woolridge devotes several pages of his testimony discussing various reasons why he believes such an adjustment is not necessary.[100]

[100] *See* Direct Testimony of DPA Witness Woolridge, at 56-58.

DPA Witness Woolridge does not account for flotation costs, asserting, among other reasons that flotation costs for stock issuances are not the same as flotation costs for debt issuances, and, even if they were, current market conditions would dictate that a *reduction* to the Cost of Equity is required to account for flotation costs. DPA Witness Woolridge also claims flotation costs are not "out-of pocket" expenses, and thus they should not be recovered through the regulatory process.[101]

Q58. Please respond to DPA Witness Woolridge in that regard.

A58. First, I disagree with DPA Witness Woolridge's position that flotation costs for stock issuances are different from flotation costs for debt issuances. Companies pay the same types of fees (both direct and indirect) regardless of whether they are issuing stocks or bonds. As to DPA Witness Woolridge's assertion that underwriter fees do not represent "out-of-pocket" expenses, I view that to be a matter of semantics. While there certainly is a difference between the offer price for securities and the price the issuing company receives, that difference still represents a direct expense to the issuer. In either case, the cost results in net proceeds that are less than gross proceeds.

I also disagree with DPA Witness Woolridge's position that flotation costs could represent a *reduction* in the Cost of Equity. Flotation costs are true costs to the issuer, and represent funds that could otherwise be invested in profitable opportunities. As explained in my Direct Testimony, to the extent a company is denied the opportunity to recover flotation costs, the company will fall short of its

101 *Ibid.*

expected (or required) return.[102]

I have provided an illustrative example of the effect of flotation costs on the ROE in Schedule (RBH-R)-14.[103] As shown in that schedule, in order for an investor to earn a required return of 11.00%, the company would need to be allowed a return of 11.32% due to the effect of flotation costs. If flotation costs are not accounted for, the resulting growth rate falls and the ROE decreases to 10.68% (*i.e.*, below the required return).[104] In addition, Dr. Roger Morin notes, "[T]he adjustment is always required each and every year, whether or not new stock issues are sold in the future…"[105]

Q59. Please comment on DPA Witness Woolridge's critique of your size premium analysis.

A59. DPA Witness Woolridge cites an article written in 1993 by Professor Annie Wong as support for his assertion that utilities are not subject to the size premium effect, however, other studies have come to the opposite conclusion. A 2002 study by T.M. Zepp specifically rebuts the arguments made by Professor Wong.[106] Zepp concludes that size premia do exist, contrary to both the informational and empirical evidence cited in the Wong study. As noted in my Direct Testimony, a second study published in 1995 by Ibbotson (now Morningstar) comes to the same conclusion.[107]

---

102 The flotation cost adjustment based on data as of June 14, 2013 is provided in Schedule (RBH-R)-13.

103 This example is based on an analysis performed by Dr. Roger Morin. *See* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 331-332.

104 Schedule (RBH-R)-14 is provided for illustrative purposes only. I have not relied on the results of the analysis in determining my recommended ROE and range.

105 Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 330.

106 *See*, T.M. Zepp, *Utility stocks and the size effect-revisited*, The Quarterly Review of Economics and Finance, August 29, 2002.

107 *See* Direct Testimony of Robert B. Hevert, at 35. *See* also Michael Annin, *Equity and the Small Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

Both of those studies are highly relevant as they focus specifically on the utility industry and the effect of the size premium in a regulated environment.

Q60. Please summarize DPA Witness Woolridge's assessment of your analysis regarding revenue stabilization mechanisms employed by the proxy companies.

A60. DPA Witness Woolridge suggests that the analysis (*see* Schedule (RBH)-10) is incomplete because it does not provide the percentage of revenues covered by the revenue stabilization mechanisms (RSM). DPA Witness Woolridge further suggests that: (1) only 68.00% of the proxy companies' revenues are derived from regulated operations; and (2) the revenues that are regulated are not necessarily covered by the RSMs. As such, DPA Witness Woolridge concludes that it is "impossible to determine the ultimate impact of RSMs on the riskiness of the gas proxy group."[108]

Q61. What is your response to DPA Witness Woolridge's assessment?

A61. Between 2010 and 2012 the revenue derived from regulated operations for the proxy group averaged 66.44%, whereas the regulated operating income averaged 88.04% (*see* Schedule (RBH-R)-15). That is, while the average regulated revenue for the proxy group is similar to that reported by DPA Witness Woolridge, the regulated operating income is significantly higher. Since investors are more likely to focus on measures of income than revenue, it is the more relevant metric. On that measure, the proxy group is comprised of substantially more regulated operations than DPA Witness Woolridge suggests.

As to the extent of their coverage, the RSMs do apply to a significant portion of the proxy companies' operations. For example, well over 95.00% of AGL

---

[108] Direct Testimony of DPA Witness Woolridge, at 61.

Resources, Inc.'s (AGL) margins are covered by regulatory mechanisms.[109] To that point, John Somerhalder, the Chairman, President and Chief Executive Officer of AGL, noted that:

> [a] high percentage of our revenues are certain, either from the amount of our cost recovery we have in the base rates, the fixed piece or from just weather that we experienced under the low cases and unfortunately last year was one of those cases. The weather normalization makes up another gap and you can see a very small amount of at-risk for revenues in our distribution operations business.[110]

Mr. Somerhalder further discussed the stabilization mechanisms in place at AGL's operating companies noting, "When you look at how certain our revenues are in the distribution business, it's very certain."[111] Similarly, as a result of purchased gas adjustment mechanisms, decoupling, a rate stabilization mechanism, and weather normalization adjustment mechanisms, 89.00% of Piedmont Natural Gas Company's utility margins were recovered on a fixed or semi-fixed basis in the year ended October 31, 2012.[112] In addition, mechanisms in place at Atmos Energy Corp. cover 74.00% to 97.00% of its natural gas distribution gross margins.[113]

---

[109] *See* AGL Resources, Inc., Investor Presentation at the American Gas Association Financial Forum, May 6, 2013, at 10.

[110] Transcript of AGL Resources, Inc., Investor Presentation at the American Gas Association Financial Forum, May 6, 2013, at 3.

[111] *Ibid.* The non-regulated operations within the proxy group also have structures in place to fix margins. For example, Sequent Energy Management, L.P., a wholly-owned subsidiary of AGL, which "is involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the United States and in Canada," engages in a variety of activities in order to hedge its risk. These include derivative instruments, such as, "a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements." While these instruments are not entirely analogous to RSMs, they do serve to stabilize revenue for the non-regulated portion of AGL's business. In fact, AGL noted, "A portion of Sequent's storage inventory is economically hedged with futures contracts, which results in realization of a substantially fixed margin, timing notwithstanding." *See* also AGL Resources Inc., SEC Form 10-K, Year ended December 31, 2012, at 11, 13, 52.

[112] *See* Piedmont Natural Gas Company, SEC Form 10-K, Year ended October 31, 2012, at 24.

[113] *See* Atmos Energy Corporation, SEC Form 10-K, Year ended September 30, 2012, at 10.

Q62. Have other regulatory commissions noted the prevalence of RSMs in arriving at ROE determinations?

A62. Yes, they have. In its most recent order regarding Baltimore Gas and Electric, the Public Service Commission of Maryland stated that:

> We will not further reduce that return as a result of BGE's decoupling mechanism. No party argued that the Company should have a reduced ROE for its natural gas operations because of decoupling. Instead, as the parties testified, decoupling provisions are common among natural gas distribution companies.[114]

Similarly, in its recent order regarding Southwest Gas, the Public Utilities Commission of Nevada also noted that RSMs have become common:

> The Commission further finds that an adjustment for SWG's revenue decoupling mechanism is unnecessary as all of the companies in the Proxy Group have some form of a rate stabilization mechanism in place.[115]

The Public Service Commission of Wyoming also provided similar guidance in approving Questar Gas' proposed Conservation Enabling Tariff. Specifically, the Public Service Commission denied an adjustment to the ROE proposed by the Office of Consumer Advocate stating:

> This suggested reduction in ROE is not appropriate because eight of the ten utilities in the proxy group Questar used in its DCF analysis have some sort of decoupling mechanism. If the decoupled utilities are part of the proxy group, the risk reduction is already accounted for when the proxy group financial parameters are used to determine a ROE for the Company. The Commission agrees with Questar that

---

114 Baltimore Gas & Electric, Public Service Commission of Maryland, Case No. 9299, Order No. 85374, February 22, 2013, at 78

115 Southwest Gas Corporation, Public Utilities Commission of Nevada, Docket No. 12-04005, Modified Final Order, December 14, 2012, at 28.

> financial analysts now tend to treat revenue stabilization measures as a norm, rather than an exception which requires adjustments.[116]

It appears that regulatory commissions have recognized the widespread use of RSMs. Given that RSMs are viewed as the "norm", it is appropriate to consider the effect that a lack of such mechanisms has on the relative risk of the Company.

V. <u>Updated Results</u>

Q63. Have you updated the analyses presented in your Direct Testimony?

A63. Yes. I have updated analyses presented in my Direct Testimony with data as of June 14, 2013.

Q64. Please summarize your updated DCF Model results.

A64. I continue to use projected earnings growth rates from Zacks, First Call, and Value Line, as well as the sustainable growth in developing my Quarterly Growth, Constant Growth and Multi-Stage DCF models. The results are shown in Table 5 (below; *see also*, Schedule (RBH-R)-1 through Schedule (RBH-R)-4).

---

116 Public Service Commission of Wyoming, Docket No. 30010-94-GR-08, Record No. 11846, Memorandum Opinion, Findings and Order, *In the Matter of the Application of the Questar Gas Company for Approval to Implement an Increase in the Non-Gas Rates and Charges for A General Rate Increase of $482,980 and for Approval of a Conservation Enabling Tariff*, June 17, 2009, at para. 50.

Table 5: Summary of Constant Growth DCF Results

	Low Growth Rate	***Mean Growth Rate***	***High Growth Rate***
	Quarterly Growth DCF		
30-Day Average	7.68%	9.04%	10.50%
90-Day Average	7.76%	9.13%	10.59%
180-Day Average	7.91%	9.28%	10.74%
	Constant Growth DCF		
30-Day Average	7.57%	8.89%	10.30%
90-Day Average	7.65%	8.97%	10.38%
180-Day Average	7.79%	9.11%	10.52%
	Multi-Stage DCF		
	Low	***Mean***	***High***
30-Day Average	9.10%	9.71%	10.02%
90-Day Average	9.17%	9.80%	10.25%
180-Day Average	9.24%	9.96%	10.43%

Q65. Please summarize your updated CAPM analysis.

A65. I continue to use the same inputs used in my Direct Testimony, updated through June 14, 2013. For the risk-free rate, I continue to refer alternatively to: (1) the 30-day average of the 30-year Treasury yield; and (2) a consensus forecast of the average 30-year Treasury yield for the coming six quarters. For the Beta Coefficient, I continue to rely on published results from Bloomberg and Value Line. For the MRP, I continue to refer to the form of *ex-ante* market risk premia that I described in my Direct Testimony: the expected return on the S&P 500 Index less the current 30-year Treasury yield, and the Sharpe Ratio derived MRP. In addition, I have also included an MRP based on Value Line data, as both Staff Witness Parcell and DPA Witness Woolridge rely extensively on data from Value Line.

Q66. What are your updated CAPM results?

A66. As shown in Schedule (RBH-R)-7 and Table 6 (below), based upon updated market information, my CAPM analyses produce a range of ROE estimates from 8.35% to 10.70%.

Table 6: Summary of CAPM Results

	Sharpe Ratio Derived Market Risk Premium	***Bloomberg Derived Market Risk Premium***	***Value Line Derived Market Risk Premium***[117]
Bloomberg Beta Coefficient			
Current 30-Year Treasury (3.20%)	8.94%	10.53%	10.36%
Near Term Projected 30-Year Treasury (3.37%)	9.11%	10.70%	10.53%
Value Line Beta Coefficient			
Current 30-Year Treasury (3.20%)	8.35%	9.78%	9.63%
Near Term Projected 30-Year Treasury (3.37%)	8.52%	9.95%	9.80%

Q67. Did you give your Sharpe Ratio-based CAPM estimates significant weight in arriving at your ROE range and recommendation?

A67. No, I did not. The CAPM results based on the Sharpe ratio derived MRP range from 8.35% to 9.11%. As discussed in my Direct Testimony, results significantly below any authorized ROE (and well below the Company's previously authorized ROE) should be given little to no weight in the context of developing a recommended ROE.[118]

In terms of the application of that model, the long-term MRP of 6.70% is

117 In my Direct Testimony, I relied on data from Bloomberg and Capital IQ to calculate the market required return. *See* Direct Testimony of Robert B. Hevert, at 28.

118 *See* Direct Testimony of Robert B. Hevert, at 24.

based on the surplus of the historical total return for large company stocks of 11.80% over the income-only return on long-term government bonds of 5.10%. Under the Sharpe Ratio approach, the expected MRP will approximate the historical MRP when expected volatility approximates historical volatility, as currently is the case.[119] And, while the Sharpe Ratio approach also is meant to capture the interaction between volatility and Treasury yields, the current 30-year Treasury yield (3.20%) is below the historical average (5.10%). Consequently, even if expected volatility is approximately equal to the historical average, the currently low level of Treasury yields suggest that the CAPM approach would understate the Company's Cost of Equity. As such, I believe the relevant range of CAPM results is 9.63% to 10.70%.

Q68. Please summarize your updated Risk Premium analysis.

A68. My updated Risk Premium analysis includes authorized ROEs as reported by Regulatory Research Associates through June 14, 2013. For the purpose of calculating the expected risk premium and ROE, I have used the current, near-term and long-term projected 30-year Treasury yield, as shown in Schedule (RBH-R)-8. My updated results are provided in Table 7 (below).

Table 7: Summary of Bond Yield Plus Risk Premium Results

Current 30-Year Treasury (3.20%)	10.10%
Near Term Projected 30-Year Treasury (3.37%)	10.12%
Long Term Projected 30-Year Treasury (5.40%)	10.77%

119 Expected volatility as measured in Schedule (RBH-R)-5 by the VIX term structure is 23.31, whereas the long term average VIX has been approximately 20.32 since its inception.

Q69. Do you believe the business risks discussed in your Direct Testimony still apply to Delmarva?

A69. Yes, I do. As discussed in my response to DPA Witness Woolridge, Delmarva is significantly smaller than the proxy companies. Also in my response to DPA Witness Woolridge, the Company is affected by flotation costs associated with the issuance of new shares. Additionally, the Company continues to face greater risk because of a relative lack of revenue stabilization mechanisms (decoupling, in particular) relative to the proxy group.

The Company employs a fuel adjustment tracker, whereas, as discussed in my Direct Testimony, each of the proxy companies utilize some form of revenue stabilization mechanism and all but one have some form of a decoupling mechanism in place in at least one of its operating jurisdictions. Looking now at the utilities that received an authorized ROE since the beginning of 2012 (*i.e.*, January 2012 through June, 14 2013), 25 of the 43 utilities employ some form of revenue decoupling. Another 12 utilities received final orders in rate cases in which the authorized ROE was not disclosed. Of those 12 companies nine employed some form of decoupling. That is, 34 of the 55 companies, or approximately 62.00% of the utilities which received final orders in their rate cases since January 2012 have some form of revenue decoupling in place.[120]

Considering that data, I continue to believe that revenue stabilization mechanisms, in particular revenue decoupling, are prevalent in the industry. As such,

[120] Source: Regulatory Research Associates. Regulatory Research Associates, *Adjustment Clauses and Rate Riders*, March 21, 2012 and American Gas Association, Innovative Rates, *Non-Volumetric Rates, and Tracking Mechanisms: Current List*, September 2012.

Delmarva's lack of such a mechanism suggests a greater risk relative to the proxy group. I also note that the 9.86% average authorized ROE since January 2012 further supports my recommended range, especially since many of the companies included in the average employ some form of revenue decoupling. Consequently, a utility lacking a decoupling mechanism would require an ROE above 9.86%, all else remaining equal.

VI. Conclusions and Recommendation

Q70. Please summarize the analyses and conclusions contained in your Rebuttal Testimony.

A70. My updated analytical results are provided in Tables 5 through 7 (above). My recommended ROE takes into account the results of these various models and analyses as well as the specific business risks faced by Delmarva, including the Company's relatively small size, the Company's lack of revenue stabilization mechanisms, including decoupling, and flotation costs. My recommended ROE also takes into account the state of the capital markets. Specifically, it is important to consider recent significant increases in Treasury bond yields, utility bond yields and the dividend yield of the proxy group. In reviewing other jurisdictions, it is obvious that Commissions consider factors beyond interest rates when determining the appropriate authorized ROEs, as authorized ROEs remained relatively stable while interest rates declined. Therefore, I conclude that the reasonable range of ROE estimates is from 10.00% to 10.75% and within that range, 10.25% is a reasonable and appropriate estimate of the Company's Cost of Equity.

Q71. Does this conclude your Rebuttal Testimony?

A71. Yes, it does.

Quarterly Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] First Call Earnings Growth	[12] Value Line Earnings Growth	[13] Sustainable Growth Estimate	[14] Average Earnings Growth	[15] Low ROE	[16] Mean ROE	[17] High ROE
AGL Resources Inc.	GAS	$0.46	$0.46	$0.47	$0.47	$0.49	$0.49	$0.50	$0.50	$43.06	3.53%	NA	9.00%	5.71%	6.08%	8.13%	10.84%	13.95%
Atmos Energy Corporation	ATO	$0.35	$0.35	$0.35	$0.35	$0.36	$0.37	$0.37	$0.37	$43.00	6.00%	6.00%	5.50%	5.65%	5.79%	9.04%	9.34%	9.56%
Laclede Group, Inc. (The)	LG	$0.42	$0.43	$0.43	$0.43	$0.44	$0.45	$0.45	$0.45	$46.34	3.00%	4.80%	5.50%	7.15%	5.11%	6.85%	9.07%	11.22%
New Jersey Resources Corporation	NJR	$0.40	$0.40	$0.40	$0.40	$0.42	$0.42	$0.42	$0.42	$45.69	4.00%	4.00%	2.00%	5.23%	3.81%	5.65%	7.55%	9.04%
Northwest Natural Gas Company	NWN	$0.45	$0.46	$0.46	$0.46	$0.46	$0.47	$0.47	$0.47	$43.97	3.83%	3.75%	5.00%	4.83%	4.35%	8.15%	8.79%	9.47%
Piedmont Natural Gas Company, Inc.	PNY	$0.30	$0.30	$0.31	$0.31	$0.31	$0.31	$0.32	$0.32	$34.15	4.30%	5.00%	3.00%	2.90%	3.80%	6.66%	7.61%	8.87%
South Jersey Industries, Inc.	SJI	$0.40	$0.44	$0.44	$0.44	$0.43	$0.48	$0.48	$0.48	$59.13	6.00%	6.00%	8.00%	9.95%	7.49%	9.20%	10.75%	13.32%
Southwest Gas Corporation	SWX	$0.30	$0.30	$0.33	$0.33	$0.31	$0.31	$0.35	$0.35	$49.10	5.25%	6.00%	7.00%	6.67%	6.23%	8.01%	9.02%	9.82%
WGL Holdings, Inc.	WGL	$0.40	$0.40	$0.40	$0.42	$0.42	$0.42	$0.42	$0.44	$44.13	5.25%	5.25%	3.50%	3.76%	4.44%	7.40%	8.39%	9.24%
Mean											4.57%	5.10%	5.39%	5.76%	5.23%	7.68%	9.04%	10.50%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [14])
[6] Equals Col. [2] x (1 + Col. [14])
[7] Equals Col. [3] x (1 + Col. [14])
[8] Equals Col. [4] x (1 + Col. [14]).
[9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of June 14, 2013
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Schedule (RBH)-3
[14] Equals Average (Cols. [10], [11], [12], [13])
[15] Implied Low DCF
[16] Implied Mean DCF
[17] Implied High DCF

Quarterly Discounted Cash Flow Model
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Sustainable Growth Estimate	Average Earnings Growth	Low ROE	Mean ROE	High ROE
AGL Resources Inc.	GAS	$0.46	$0.46	$0.47	$0.47	$0.49	$0.49	$0.50	$0.50	$42.00	3.53%	NA	9.00%	5.71%	6.08%	8.25%	10.97%	14.07%
Atmos Energy Corporation	ATO	$0.35	$0.35	$0.35	$0.35	$0.36	$0.37	$0.37	$0.37	$41.74	6.00%	6.00%	5.50%	5.65%	5.79%	9.14%	9.44%	9.67%
Laclede Group, Inc. (The)	LG	$0.42	$0.43	$0.43	$0.43	$0.44	$0.45	$0.45	$0.45	$43.72	3.00%	4.80%	5.50%	7.15%	5.11%	7.09%	9.32%	11.47%
New Jersey Resources Corporation	NJR	$0.40	$0.40	$0.40	$0.40	$0.42	$0.42	$0.42	$0.42	$45.14	4.00%	4.00%	2.00%	5.23%	3.81%	5.69%	7.59%	9.09%
Northwest Natural Gas Company	NWN	$0.45	$0.46	$0.46	$0.46	$0.46	$0.47	$0.47	$0.47	$44.37	3.83%	3.75%	5.00%	4.83%	4.35%	8.11%	8.74%	9.43%
Piedmont Natural Gas Company, Inc.	PNY	$0.30	$0.30	$0.31	$0.31	$0.31	$0.31	$0.32	$0.32	$33.49	4.30%	5.00%	3.00%	2.90%	3.80%	6.74%	7.69%	8.95%
South Jersey Industries, Inc.	SJI	$0.40	$0.44	$0.44	$0.44	$0.43	$0.48	$0.48	$0.48	$57.26	6.00%	6.00%	8.00%	9.95%	7.49%	9.31%	10.86%	13.43%
Southwest Gas Corporation	SWX	$0.30	$0.30	$0.33	$0.33	$0.31	$0.31	$0.35	$0.35	$47.89	5.25%	6.00%	7.00%	6.67%	6.23%	8.08%	9.09%	9.89%
WGL Holdings, Inc.	WGL	$0.40	$0.40	$0.40	$0.42	$0.42	$0.42	$0.42	$0.44	$43.71	5.25%	5.25%	3.50%	3.76%	4.44%	7.44%	8.43%	9.28%
Mean											4.57%	5.10%	5.39%	5.76%	5.23%	7.76%	9.13%	10.59%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [14])
[6] Equals Col. [2] x (1 + Col. [14])
[7] Equals Col. [3] x (1 + Col. [14])
[8] Equals Col. [4] x (1 + Col. [14])
[9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of June 14, 2013
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Schedule (RBH)-3
[14] Equals Average (Cols. [10], [11], [12], [13])
[15] Implied Low DCF
[16] Implied Mean DCF
[17] Implied High DCF

Quarterly Discounted Cash Flow Model
180 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Sustainable Growth Estimate	Average Earnings Growth	Low ROE	Mean ROE	High ROE
AGL Resources Inc.	GAS	$0.46	$0.46	$0.47	$0.47	$0.49	$0.49	$0.50	$0.50	$41.06	3.53%	NA	9.00%	5.71%	6.08%	8.36%	11.08%	14.19%
Atmos Energy Corporation	ATO	$0.35	$0.35	$0.35	$0.35	$0.36	$0.37	$0.37	$0.37	$38.71	6.00%	6.00%	5.50%	5.65%	5.79%	9.43%	9.73%	9.96%
Laclede Group, Inc. (The)	LG	$0.42	$0.43	$0.43	$0.43	$0.44	$0.45	$0.45	$0.45	$41.99	3.00%	4.80%	5.50%	7.15%	5.11%	7.26%	9.49%	11.65%
New Jersey Resources Corporation	NJR	$0.40	$0.40	$0.40	$0.40	$0.42	$0.42	$0.42	$0.42	$43.60	4.00%	4.00%	2.00%	5.23%	3.81%	5.82%	7.73%	9.23%
Northwest Natural Gas Company	NWN	$0.45	$0.46	$0.46	$0.46	$0.46	$0.47	$0.47	$0.47	$44.92	3.83%	3.75%	5.00%	4.83%	4.35%	8.05%	8.69%	9.38%
Piedmont Natural Gas Company, Inc.	PNY	$0.30	$0.30	$0.31	$0.31	$0.31	$0.31	$0.32	$0.32	$32.48	4.30%	5.00%	3.00%	2.90%	3.80%	6.86%	7.81%	9.07%
South Jersey Industries, Inc.	SJI	$0.40	$0.44	$0.44	$0.44	$0.43	$0.48	$0.48	$0.48	$54.16	6.00%	6.00%	8.00%	9.95%	7.49%	9.50%	11.06%	13.63%
Southwest Gas Corporation	SWX	$0.30	$0.30	$0.33	$0.33	$0.31	$0.31	$0.35	$0.35	$45.40	5.25%	6.00%	7.00%	6.67%	6.23%	8.23%	9.25%	10.05%
WGL Holdings, Inc.	WGL	$0.40	$0.40	$0.40	$0.42	$0.42	$0.42	$0.42	$0.44	$41.55	5.25%	5.25%	3.50%	3.76%	4.44%	7.65%	8.64%	9.50%
Mean											4.57%	5.10%	5.39%	5.76%	5.23%	7.91%	9.28%	10.74%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [14])
[6] Equals Col. [2] x (1 + Col. [14])
[7] Equals Col. [3] x (1 + Col. [14])
[8] Equals Col. [4] x (1 + Col. [14])
[9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of June 14, 2013
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Schedule (RBH)-3
[14] Equals Average (Cols. [10], [11], [12], [13])
[15] Implied Low DCF
[16] Implied Mean DCF
[17] Implied High DCF

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Sustainable Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
AGL Resources Inc.	GAS	$1.88	$43.06	4.37%	4.50%	3.53%	NA	9.00%	5.71%	6.08%	7.97%	10.58%	13.56%
Atmos Energy Corporation	ATO	$1.40	$43.00	3.26%	3.35%	6.00%	6.00%	5.50%	5.65%	5.79%	8.85%	9.14%	9.35%
Laclede Group, Inc. (The)	LG	$1.70	$46.34	3.67%	3.76%	3.00%	4.80%	5.50%	7.15%	5.11%	6.72%	8.88%	10.95%
New Jersey Resources Corporation	NJR	$1.60	$45.69	3.50%	3.57%	4.00%	4.00%	2.00%	5.23%	3.81%	5.54%	7.38%	8.83%
Northwest Natural Gas Company	NWN	$1.82	$43.97	4.14%	4.23%	3.83%	3.75%	5.00%	4.83%	4.35%	7.97%	8.58%	9.24%
Piedmont Natural Gas Company, Inc.	PNY	$1.24	$34.15	3.63%	3.70%	4.30%	5.00%	3.00%	2.90%	3.80%	6.58%	7.50%	8.72%
South Jersey Industries, Inc.	SJI	$1.77	$59.13	2.99%	3.11%	6.00%	6.00%	8.00%	9.95%	7.49%	9.08%	10.59%	13.09%
Southwest Gas Corporation	SWX	$1.32	$49.10	2.69%	2.77%	5.25%	6.00%	7.00%	6.67%	6.23%	8.01%	9.00%	9.78%
WGL Holdings, Inc.	WGL	$1.68	$44.13	3.81%	3.89%	5.25%	5.25%	3.50%	3.76%	4.44%	7.37%	8.33%	9.16%
Mean				3.56%	3.65%	4.57%	5.10%	5.39%	5.76%	5.23%	7.57%	8.89%	10.30%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of June 14, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Schedule (RBH)-3
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Sustainable Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
AGL Resources Inc.	GAS	$1.88	$42.00	4.48%	4.61%	3.53%	NA	9.00%	5.71%	6.08%	8.09%	10.69%	13.68%
Atmos Energy Corporation	ATO	$1.40	$41.74	3.35%	3.45%	6.00%	6.00%	5.50%	5.65%	5.79%	8.95%	9.24%	9.45%
Laclede Group, Inc. (The)	LG	$1.70	$43.72	3.89%	3.99%	3.00%	4.80%	5.50%	7.15%	5.11%	6.95%	9.10%	11.18%
New Jersey Resources Corporation	NJR	$1.60	$45.14	3.54%	3.61%	4.00%	4.00%	2.00%	5.23%	3.81%	5.58%	7.42%	8.87%
Northwest Natural Gas Company	NWN	$1.82	$44.37	4.10%	4.19%	3.83%	3.75%	5.00%	4.83%	4.35%	7.93%	8.54%	9.20%
Piedmont Natural Gas Company, Inc.	PNY	$1.24	$33.49	3.70%	3.77%	4.30%	5.00%	3.00%	2.90%	3.80%	6.65%	7.57%	8.79%
South Jersey Industries, Inc.	SJI	$1.77	$57.26	3.09%	3.21%	6.00%	6.00%	8.00%	9.95%	7.49%	9.18%	10.69%	13.19%
Southwest Gas Corporation	SWX	$1.32	$47.89	2.76%	2.84%	5.25%	6.00%	7.00%	6.67%	6.23%	8.08%	9.07%	9.85%
WGL Holdings, Inc.	WGL	$1.68	$43.71	3.84%	3.93%	5.25%	5.25%	3.50%	3.76%	4.44%	7.41%	8.37%	9.19%
Mean				3.64%	3.73%	4.57%	5.10%	5.39%	5.76%	5.23%	7.65%	8.97%	10.38%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of June 14, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Schedule (RBH)-3
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Sustainable Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
AGL Resources Inc.	GAS	$1.88	$41.06	4.58%	4.72%	3.53%	NA	9.00%	5.71%	6.08%	8.19%	10.80%	13.79%
Atmos Energy Corporation	ATO	$1.40	$38.71	3.62%	3.72%	6.00%	6.00%	5.50%	5.65%	5.79%	9.22%	9.51%	9.73%
Laclede Group, Inc. (The)	LG	$1.70	$41.99	4.05%	4.15%	3.00%	4.80%	5.50%	7.15%	5.11%	7.11%	9.27%	11.35%
New Jersey Resources Corporation	NJR	$1.60	$43.60	3.67%	3.74%	4.00%	4.00%	2.00%	5.23%	3.81%	5.71%	7.55%	9.00%
Northwest Natural Gas Company	NWN	$1.82	$44.92	4.05%	4.14%	3.83%	3.75%	5.00%	4.83%	4.35%	7.88%	8.49%	9.15%
Piedmont Natural Gas Company, Inc.	PNY	$1.24	$32.48	3.82%	3.89%	4.30%	5.00%	3.00%	2.90%	3.80%	6.77%	7.69%	8.91%
South Jersey Industries, Inc.	SJI	$1.77	$54.16	3.27%	3.39%	6.00%	6.00%	8.00%	9.95%	7.49%	9.37%	10.88%	13.38%
Southwest Gas Corporation	SWX	$1.32	$45.40	2.91%	3.00%	5.25%	6.00%	7.00%	6.67%	6.23%	8.23%	9.23%	10.01%
WGL Holdings, Inc.	WGL	$1.68	$41.55	4.04%	4.13%	5.25%	5.25%	3.50%	3.76%	4.44%	7.61%	8.57%	9.40%
Mean				3.78%	3.88%	4.57%	5.10%	5.39%	5.76%	5.23%	7.79%	9.11%	10.52%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of June 14, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Schedule (RBH)-3
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Retention Growth Estimate

Company	Ticker	[1] Projected Earnings per share 2016-18	[2] Projected Dividend Declared per share 2016-18	[3] Retention Ratio (B)	[4] Projected Book Value per Share 2016-18	[5] Return on Book Value (R)	[6] B x R	[7] Projected Common Shares Outstanding 2014	[8] Projected Common Shares Outstanding 2016-18	[9] Common Shares Growth Rate	[10] 2013 High Price	[11] 2013 Low Price	[12] 2013 price midpoint	[13] Projected Book Value per Share 2013	[14] Market/ Book Ratio	[15] "S"	[16] "V"	[17] S x V	[18] BR + SV
AGL Resources Inc.	GAS	4.10	2.04	50.24%	36.05	11.37%	5.71%	117.00	117.00	0.00%	44.8	38.9	$ 41.85	32.80	1.28	0.00%	21.62%	0.00%	5.71%
Atmos Energy Corporation	ATO	3.00	1.50	50.00%	34.65	8.66%	4.33%	92.00	103.00	3.80%	45.1	34.9	$ 40.00	29.70	1.35	5.11%	25.75%	1.32%	5.65%
Laclede Group, Inc. (The)	LG	3.75	1.82	51.47%	28.65	13.09%	6.74%	23.00	23.50	0.71%	47.1	37.4	$ 42.25	26.65	1.59	1.13%	36.92%	0.42%	7.15%
New Jersey Resources Corporation	NJR	2.95	1.72	41.69%	23.50	12.55%	5.23%	40.00	40.00	0.00%	47.6	39.1	$ 43.35	18.70	2.32	0.00%	56.86%	0.00%	5.23%
Northwest Natural Gas Company	NWN	3.30	2.00	39.39%	31.70	10.41%	4.10%	27.00	28.00	1.21%	46.6	43.0	$ 44.80	28.00	1.60	1.93%	37.50%	0.72%	4.83%
Piedmont Natural Gas Company, Inc.	PNY	1.90	1.39	26.84%	17.60	10.80%	2.90%	76.00	76.00	0.00%	35.5	30.9	$ 33.20	15.65	2.12	0.00%	52.86%	0.00%	2.90%
South Jersey Industries, Inc.	SJI	4.60	2.45	46.74%	30.55	15.06%	7.04%	33.50	36.00	2.40%	61.8	50.5	$ 56.15	25.40	2.21	5.31%	54.76%	2.91%	9.95%
Southwest Gas Corporation	SWX	3.75	1.60	57.33%	36.00	10.42%	5.97%	48.00	50.00	1.36%	51.5	42.0	$ 46.75	30.85	1.52	2.06%	34.01%	0.70%	6.67%
WGL Holdings, Inc.	WGL	2.95	1.83	37.97%	29.80	9.90%	3.76%	52.00	52.00	0.00%	46.2	38.3	$ 42.25	25.60	1.65	0.00%	39.41%	0.00%	3.76%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.33 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Source: Value Line
[14] Equals [12] / [13]
[15] Equals [9] x [14]
[16] Equals 1 - (1 / [14])
[17] Equals [15] x [16]
[18] Equals [6] + [17]

Multistage Growth Discounted Cash Flow Model
30 Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term		Payout Ratio		Iterative Solution		Terminal	Terminal
						Sustainable									
Company	Ticker	Price	Zacks	First Call	Value Line	Growth	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
AGL Resources Inc.	GAS	$43.06	3.53%	NA	9.00%	5.71%	6.08%	5.70%	74.00%	50.00%	69.45%	($0.00)	9.89%	16.60	2.91
Atmos Energy Corp.	ATO	$43.00	6.00%	6.00%	5.50%	5.65%	5.79%	5.70%	57.00%	50.00%	69.45%	($0.00)	9.36%	18.98	3.33
Laclede Group, Inc.	LG	$46.34	3.00%	4.80%	5.50%	7.15%	5.11%	5.70%	61.00%	48.00%	69.45%	($0.00)	10.00%	16.16	2.83
New Jersey Resources	NJR	$45.69	4.00%	4.00%	2.00%	5.23%	3.81%	5.70%	61.00%	58.00%	69.45%	($0.00)	9.69%	17.41	3.05
Northwest Natural Gas	NWN	$43.97	3.83%	3.75%	5.00%	4.83%	4.35%	5.70%	80.00%	60.00%	69.45%	($0.00)	9.31%	19.24	3.37
Piedmont Natural Gas	PNY	$34.15	4.30%	5.00%	3.00%	2.90%	3.80%	5.70%	72.00%	72.00%	69.45%	($0.00)	9.10%	20.44	3.58
South Jersey Industries	SJI	$59.13	6.00%	6.00%	8.00%	9.95%	7.49%	5.70%	56.00%	52.00%	69.45%	($0.00)	9.98%	16.25	2.85
Southwest Gas Corp.	SWX	$49.10	5.25%	6.00%	7.00%	6.67%	6.23%	5.70%	44.00%	43.00%	69.45%	($0.00)	10.02%	16.09	2.82
WGL Holdings, Inc.	WGL	$44.13	5.25%	5.25%	3.50%	3.76%	4.44%	5.70%	65.00%	61.00%	69.45%	($0.00)	10.01%	16.13	2.83
												MEAN	9.71%		
												MAX	10.02%		
												MIN	9.10%		

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AGL Resources Inc.	GAS	$2.32	$2.46	$2.61	$2.77	$2.94	$3.12	$3.30	$3.50	$3.71	$3.92	$4.15	$4.39	$4.64	$4.90	$5.18	$5.48	$5.79
Atmos Energy Corp.	ATO	$2.10	$2.22	$2.35	$2.49	$2.63	$2.78	$2.94	$3.11	$3.29	$3.48	$3.68	$3.89	$4.11	$4.34	$4.59	$4.85	$5.13
Laclede Group, Inc.	LG	$2.79	$2.93	$3.08	$3.24	$3.41	$3.58	$3.77	$3.97	$4.18	$4.41	$4.66	$4.92	$5.21	$5.50	$5.82	$6.15	$6.50
New Jersey Resources	NJR	$2.71	$2.81	$2.92	$3.03	$3.15	$3.27	$3.40	$3.55	$3.72	$3.91	$4.12	$4.36	$4.60	$4.87	$5.14	$5.44	$5.75
Northwest Natural Gas	NWN	$2.22	$2.32	$2.42	$2.52	$2.63	$2.75	$2.87	$3.01	$3.16	$3.33	$3.51	$3.71	$3.92	$4.15	$4.38	$4.63	$4.90
Piedmont Natural Gas	PNY	$1.66	$1.72	$1.79	$1.86	$1.93	$2.00	$2.08	$2.17	$2.28	$2.39	$2.52	$2.67	$2.82	$2.98	$3.15	$3.33	$3.52
South Jersey Industries	SJI	$3.03	$3.26	$3.50	$3.76	$4.04	$4.35	$4.66	$4.98	$5.31	$5.64	$5.98	$6.32	$6.68	$7.07	$7.47	$7.89	$8.35
Southwest Gas Corp.	SWX	$2.86	$3.04	$3.23	$3.43	$3.64	$3.87	$4.11	$4.36	$4.62	$4.89	$5.17	$5.46	$5.78	$6.11	$6.45	$6.82	$7.21
WGL Holdings, Inc.	WGL	$2.68	$2.80	$2.92	$3.05	$3.19	$3.33	$3.48	$3.65	$3.84	$4.04	$4.26	$4.51	$4.76	$5.04	$5.32	$5.63	$5.95

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
AGL Resources Inc.	GAS	74.00%	68.00%	62.00%	56.00%	50.00%	53.24%	56.48%	59.73%	62.97%	66.21%	69.45%	69.45%	69.45%	69.45%	69.45%
Atmos Energy Corp.	ATO	57.00%	55.25%	53.50%	51.75%	50.00%	53.24%	56.48%	59.73%	62.97%	66.21%	69.45%	69.45%	69.45%	69.45%	69.45%
Laclede Group, Inc.	LG	61.00%	57.75%	54.50%	51.25%	48.00%	51.58%	55.15%	58.73%	62.30%	65.88%	69.45%	69.45%	69.45%	69.45%	69.45%
New Jersey Resources	NJR	61.00%	60.25%	59.50%	58.75%	58.00%	59.91%	61.82%	63.73%	65.63%	67.54%	69.45%	69.45%	69.45%	69.45%	69.45%
Northwest Natural Gas	NWN	80.00%	75.00%	70.00%	65.00%	60.00%	61.58%	63.15%	64.73%	66.30%	67.88%	69.45%	69.45%	69.45%	69.45%	69.45%
Piedmont Natural Gas	PNY	72.00%	72.00%	72.00%	72.00%	72.00%	71.58%	71.15%	70.73%	70.30%	69.88%	69.45%	69.45%	69.45%	69.45%	69.45%
South Jersey Industries	SJI	56.00%	55.00%	54.00%	53.00%	52.00%	54.91%	57.82%	60.73%	63.63%	66.54%	69.45%	69.45%	69.45%	69.45%	69.45%
Southwest Gas Corp.	SWX	44.00%	43.75%	43.50%	43.25%	43.00%	47.41%	51.82%	56.23%	60.63%	65.04%	69.45%	69.45%	69.45%	69.45%	69.45%
WGL Holdings, Inc.	WGL	65.00%	64.00%	63.00%	62.00%	61.00%	62.41%	63.82%	65.23%	66.63%	68.04%	69.45%	69.45%	69.45%	69.45%	69.45%

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
AGL Resources Inc.	GAS	$1.82	$1.78	$1.72	$1.65	$1.56	$1.76	$1.98	$2.21	$2.47	$2.75	$3.05	$3.22	$3.40	$3.60	$3.80	$96.11
Atmos Energy Corp.	ATO	$1.27	$1.30	$1.33	$1.36	$1.39	$1.57	$1.76	$1.97	$2.19	$2.44	$2.70	$2.85	$3.02	$3.19	$3.37	$97.38
Laclede Group, Inc.	LG	$1.79	$1.78	$1.77	$1.75	$1.72	$1.94	$2.19	$2.46	$2.75	$3.07	$3.42	$3.62	$3.82	$4.04	$4.27	$104.98
New Jersey Resources	NJR	$1.72	$1.76	$1.80	$1.85	$1.89	$2.04	$2.20	$2.37	$2.57	$2.78	$3.03	$3.20	$3.38	$3.57	$3.78	$100.08
Northwest Natural Gas	NWN	$1.85	$1.81	$1.77	$1.71	$1.65	$1.77	$1.90	$2.05	$2.21	$2.38	$2.58	$2.72	$2.88	$3.04	$3.22	$94.19
Piedmont Natural Gas	PNY	$1.24	$1.29	$1.34	$1.39	$1.44	$1.49	$1.55	$1.61	$1.68	$1.76	$1.85	$1.96	$2.07	$2.19	$2.31	$71.91
South Jersey Industries	SJI	$1.82	$1.93	$2.03	$2.14	$2.26	$2.56	$2.88	$3.22	$3.59	$3.98	$4.39	$4.64	$4.91	$5.19	$5.48	$135.61
Southwest Gas Corp.	SWX	$1.34	$1.41	$1.49	$1.58	$1.66	$1.95	$2.26	$2.59	$2.96	$3.36	$3.80	$4.01	$4.24	$4.48	$4.74	$116.01
WGL Holdings, Inc.	WGL	$1.82	$1.87	$1.92	$1.98	$2.03	$2.17	$2.33	$2.50	$2.69	$2.90	$3.13	$3.31	$3.50	$3.70	$3.91	$95.92

Projected Annual Data Investor Cash Flows		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	6/14/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
AGL Resources Inc.	GAS	($43.06)	$0.00	$1.00	$1.88	$1.72	$1.65	$1.56	$1.76	$1.98	$2.21	$2.47	$2.75	$3.05	$3.22	$3.40	$3.60	$99.91
Atmos Energy Corp.	ATO	($43.00)	$0.00	$0.69	$1.30	$1.33	$1.36	$1.39	$1.57	$1.76	$1.97	$2.19	$2.44	$2.70	$2.85	$3.02	$3.19	$100.75
Laclede Group, Inc.	LG	($46.34)	$0.00	$0.98	$1.83	$1.77	$1.75	$1.72	$1.94	$2.19	$2.46	$2.75	$3.07	$3.42	$3.62	$3.82	$4.04	$109.25
New Jersey Resources	NJR	($45.69)	$0.00	$0.94	$1.75	$1.80	$1.85	$1.89	$2.04	$2.20	$2.37	$2.57	$2.78	$3.03	$3.20	$3.38	$3.57	$103.85
Northwest Natural Gas	NWN	($43.97)	$0.00	$1.02	$1.89	$1.77	$1.71	$1.65	$1.77	$1.90	$2.05	$2.21	$2.38	$2.58	$2.72	$2.88	$3.04	$97.41
Piedmont Natural Gas	PNY	($34.15)	$0.00	$0.68	$1.26	$1.34	$1.39	$1.44	$1.49	$1.55	$1.61	$1.68	$1.76	$1.85	$1.96	$2.07	$2.19	$74.22
South Jersey Industries	SJI	($59.13)	$0.00	$1.00	$1.89	$2.03	$2.14	$2.26	$2.56	$2.88	$3.22	$3.59	$3.98	$4.39	$4.64	$4.91	$5.19	$141.09
Southwest Gas Corp.	SWX	($49.10)	$0.00	$0.73	$1.38	$1.49	$1.58	$1.66	$1.95	$2.26	$2.59	$2.96	$3.36	$3.80	$4.01	$4.24	$4.48	$120.75
WGL Holdings, Inc.	WGL	($44.13)	$0.00	$1.00	$1.86	$1.92	$1.98	$2.03	$2.17	$2.33	$2.50	$2.69	$2.90	$3.13	$3.31	$3.50	$3.70	$99.83

Multistage Growth Discounted Cash Flow Model
90 Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
						Sustainable									
Company	Ticker	Price	Zacks	First Call	Value Line	Growth	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
AGL Resources Inc.	GAS	$42.00	3.53%	NA	9.00%	5.71%	6.08%	5.70%	74.00%	50.00%	69.45%	($0.00)	9.99%	16.20	2.84
Atmos Energy Corp.	ATO	$41.74	6.00%	6.00%	5.50%	5.65%	5.79%	5.70%	57.00%	50.00%	69.45%	($0.00)	9.47%	18.44	3.23
Laclede Group, Inc.	LG	$43.72	3.00%	4.80%	5.50%	7.15%	5.11%	5.70%	61.00%	48.00%	69.45%	($0.00)	10.25%	15.27	2.68
New Jersey Resources	NJR	$45.14	4.00%	4.00%	2.00%	5.23%	3.81%	5.70%	61.00%	58.00%	69.45%	($0.00)	9.74%	17.20	3.02
Northwest Natural Gas	NWN	$44.37	3.83%	3.75%	5.00%	4.83%	4.35%	5.70%	80.00%	60.00%	69.45%	($0.00)	9.28%	19.42	3.40
Piedmont Natural Gas	PNY	$33.49	4.30%	5.00%	3.00%	2.90%	3.80%	5.70%	72.00%	72.00%	69.45%	($0.00)	9.17%	20.03	3.51
South Jersey Industries	SJI	$57.26	6.00%	6.00%	8.00%	9.95%	7.49%	5.70%	56.00%	52.00%	69.45%	($0.00)	10.11%	15.76	2.76
Southwest Gas Corp.	SWX	$47.89	5.25%	6.00%	7.00%	6.67%	6.23%	5.70%	44.00%	43.00%	69.45%	($0.00)	10.12%	15.72	2.76
WGL Holdings, Inc.	WGL	$43.71	5.25%	5.25%	3.50%	3.76%	4.44%	5.70%	65.00%	61.00%	69.45%	($0.00)	10.05%	15.97	2.80
												MEAN	9.80%		
												MAX	10.25%		
												MIN	9.17%		

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AGL Resources Inc.	GAS	$2.32	$2.46	$2.61	$2.77	$2.94	$3.12	$3.30	$3.50	$3.71	$3.92	$4.15	$4.39	$4.64	$4.90	$5.18	$5.48	$5.79
Atmos Energy Corp.	ATO	$2.10	$2.22	$2.35	$2.49	$2.63	$2.78	$2.94	$3.11	$3.29	$3.48	$3.68	$3.89	$4.11	$4.34	$4.59	$4.85	$5.13
Laclede Group, Inc.	LG	$2.79	$2.93	$3.08	$3.24	$3.41	$3.58	$3.77	$3.97	$4.18	$4.41	$4.66	$4.92	$5.21	$5.50	$5.82	$6.15	$6.50
New Jersey Resources	NJR	$2.71	$2.81	$2.92	$3.03	$3.15	$3.27	$3.40	$3.55	$3.72	$3.91	$4.12	$4.36	$4.60	$4.87	$5.14	$5.44	$5.75
Northwest Natural Gas	NWN	$2.22	$2.32	$2.42	$2.52	$2.63	$2.75	$2.87	$3.01	$3.16	$3.33	$3.51	$3.71	$3.92	$4.15	$4.38	$4.63	$4.90
Piedmont Natural Gas	PNY	$1.66	$1.72	$1.79	$1.86	$1.93	$2.00	$2.08	$2.17	$2.28	$2.39	$2.52	$2.67	$2.82	$2.98	$3.15	$3.33	$3.52
South Jersey Industries	SJI	$3.03	$3.26	$3.50	$3.76	$4.04	$4.35	$4.66	$4.98	$5.31	$5.64	$5.98	$6.32	$6.68	$7.07	$7.47	$7.89	$8.35
Southwest Gas Corp.	SWX	$2.86	$3.04	$3.23	$3.43	$3.64	$3.87	$4.11	$4.36	$4.62	$4.89	$5.17	$5.46	$5.78	$6.11	$6.45	$6.82	$7.21
WGL Holdings, Inc.	WGL	$2.68	$2.80	$2.92	$3.05	$3.19	$3.33	$3.48	$3.65	$3.84	$4.04	$4.26	$4.51	$4.76	$5.04	$5.32	$5.63	$5.95

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
AGL Resources Inc.	GAS	74.00%	68.00%	62.00%	56.00%	50.00%	53.24%	56.48%	59.73%	62.97%	66.21%	69.45%	69.45%	69.45%	69.45%	69.45%
Atmos Energy Corp.	ATO	57.00%	55.25%	53.50%	51.75%	50.00%	53.24%	56.48%	59.73%	62.97%	66.21%	69.45%	69.45%	69.45%	69.45%	69.45%
Laclede Group, Inc.	LG	61.00%	57.75%	54.50%	51.25%	48.00%	51.58%	55.15%	58.73%	62.30%	65.88%	69.45%	69.45%	69.45%	69.45%	69.45%
New Jersey Resources	NJR	61.00%	60.25%	59.50%	58.75%	58.00%	59.91%	61.82%	63.73%	65.63%	67.54%	69.45%	69.45%	69.45%	69.45%	69.45%
Northwest Natural Gas	NWN	80.00%	75.00%	70.00%	65.00%	60.00%	61.58%	63.15%	64.73%	66.30%	67.88%	69.45%	69.45%	69.45%	69.45%	69.45%
Piedmont Natural Gas	PNY	72.00%	72.00%	72.00%	72.00%	72.00%	71.58%	71.15%	70.73%	70.30%	69.88%	69.45%	69.45%	69.45%	69.45%	69.45%
South Jersey Industries	SJI	56.00%	55.00%	54.00%	53.00%	52.00%	54.91%	57.82%	60.73%	63.63%	66.54%	69.45%	69.45%	69.45%	69.45%	69.45%
Southwest Gas Corp.	SWX	44.00%	43.75%	43.50%	43.25%	43.00%	47.41%	51.82%	56.23%	60.63%	65.04%	69.45%	69.45%	69.45%	69.45%	69.45%
WGL Holdings, Inc.	WGL	65.00%	64.00%	63.00%	62.00%	61.00%	62.41%	63.82%	65.23%	66.63%	68.04%	69.45%	69.45%	69.45%	69.45%	69.45%

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
AGL Resources Inc.	GAS	$1.82	$1.78	$1.72	$1.65	$1.56	$1.76	$1.98	$2.21	$2.47	$2.75	$3.05	$3.22	$3.40	$3.60	$3.80	$93.77
Atmos Energy Corp.	ATO	$1.27	$1.30	$1.33	$1.36	$1.39	$1.57	$1.76	$1.97	$2.19	$2.44	$2.70	$2.85	$3.02	$3.19	$3.37	$94.61
Laclede Group, Inc.	LG	$1.79	$1.78	$1.77	$1.75	$1.72	$1.94	$2.19	$2.46	$2.75	$3.07	$3.42	$3.62	$3.82	$4.04	$4.27	$99.22
New Jersey Resources	NJR	$1.72	$1.76	$1.80	$1.85	$1.89	$2.04	$2.20	$2.37	$2.57	$2.78	$3.03	$3.20	$3.38	$3.57	$3.78	$98.87
Northwest Natural Gas	NWN	$1.85	$1.81	$1.77	$1.71	$1.65	$1.77	$1.90	$2.05	$2.21	$2.38	$2.58	$2.72	$2.88	$3.04	$3.22	$95.07
Piedmont Natural Gas	PNY	$1.24	$1.29	$1.34	$1.39	$1.44	$1.49	$1.55	$1.61	$1.68	$1.76	$1.85	$1.96	$2.07	$2.19	$2.31	$70.49
South Jersey Industries	SJI	$1.82	$1.93	$2.03	$2.14	$2.26	$2.56	$2.88	$3.22	$3.59	$3.98	$4.39	$4.64	$4.91	$5.19	$5.48	$131.49
Southwest Gas Corp.	SWX	$1.34	$1.41	$1.49	$1.58	$1.66	$1.95	$2.26	$2.59	$2.96	$3.36	$3.80	$4.01	$4.24	$4.48	$4.74	$113.35
WGL Holdings, Inc.	WGL	$1.82	$1.87	$1.92	$1.98	$2.03	$2.17	$2.33	$2.50	$2.69	$2.90	$3.13	$3.31	$3.50	$3.70	$3.91	$95.01

Projected Annual Data Investor Cash Flows		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	6/14/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
AGL Resources Inc.	GAS	($42.00)	$0.00	$1.00	$1.88	$1.72	$1.65	$1.56	$1.76	$1.98	$2.21	$2.47	$2.75	$3.05	$3.22	$3.40	$3.60	$97.57
Atmos Energy Corp.	ATO	($41.74)	$0.00	$0.69	$1.30	$1.33	$1.36	$1.39	$1.57	$1.76	$1.97	$2.19	$2.44	$2.70	$2.85	$3.02	$3.19	$97.98
Laclede Group, Inc.	LG	($43.72)	$0.00	$0.98	$1.83	$1.77	$1.75	$1.72	$1.94	$2.19	$2.46	$2.75	$3.07	$3.42	$3.62	$3.82	$4.04	$103.49
New Jersey Resources	NJR	($45.14)	$0.00	$0.94	$1.75	$1.80	$1.85	$1.89	$2.04	$2.20	$2.37	$2.57	$2.78	$3.03	$3.20	$3.38	$3.57	$102.64
Northwest Natural Gas	NWN	($44.37)	$0.00	$1.02	$1.89	$1.77	$1.71	$1.65	$1.77	$1.90	$2.05	$2.21	$2.38	$2.58	$2.72	$2.88	$3.04	$98.29
Piedmont Natural Gas	PNY	($33.49)	$0.00	$0.68	$1.26	$1.34	$1.39	$1.44	$1.49	$1.55	$1.61	$1.68	$1.76	$1.85	$1.96	$2.07	$2.19	$72.80
South Jersey Industries	SJI	($57.26)	$0.00	$1.00	$1.89	$2.03	$2.14	$2.26	$2.56	$2.88	$3.22	$3.59	$3.98	$4.39	$4.64	$4.91	$5.19	$136.97
Southwest Gas Corp.	SWX	($47.89)	$0.00	$0.73	$1.38	$1.49	$1.58	$1.66	$1.95	$2.26	$2.59	$2.96	$3.36	$3.80	$4.01	$4.24	$4.48	$118.09
WGL Holdings, Inc.	WGL	($43.71)	$0.00	$1.00	$1.86	$1.92	$1.98	$2.03	$2.17	$2.33	$2.50	$2.69	$2.90	$3.13	$3.31	$3.50	$3.70	$98.92

Multistage Growth Discounted Cash Flow Model
180 Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Sustainable Growth	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
AGL Resources Inc.	GAS	$41.06	3.53%	NA	9.00%	5.71%	6.08%	5.70%	74.00%	50.00%	69.45%	($0.00)	10.09%	15.84	2.78
Atmos Energy Corp.	ATO	$38.71	6.00%	6.00%	5.50%	5.65%	5.79%	5.70%	57.00%	50.00%	69.45%	($0.00)	9.75%	17.14	3.01
Laclede Group, Inc.	LG	$41.99	3.00%	4.80%	5.50%	7.15%	5.11%	5.70%	61.00%	48.00%	69.45%	($0.00)	10.43%	14.68	2.57
New Jersey Resources	NJR	$43.60	4.00%	4.00%	2.00%	5.23%	3.81%	5.70%	61.00%	58.00%	69.45%	($0.00)	9.88%	16.61	2.91
Northwest Natural Gas	NWN	$44.92	3.83%	3.75%	5.00%	4.83%	4.35%	5.70%	80.00%	60.00%	69.45%	($0.00)	9.24%	19.66	3.45
Piedmont Natural Gas	PNY	$32.48	4.30%	5.00%	3.00%	2.90%	3.80%	5.70%	72.00%	72.00%	69.45%	($0.00)	9.28%	19.40	3.40
South Jersey Industries	SJI	$54.16	6.00%	6.00%	8.00%	9.95%	7.49%	5.70%	56.00%	52.00%	69.45%	($0.00)	10.35%	14.94	2.62
Southwest Gas Corp.	SWX	$45.40	5.25%	6.00%	7.00%	6.67%	6.23%	5.70%	44.00%	43.00%	69.45%	($0.00)	10.35%	14.95	2.62
WGL Holdings, Inc.	WGL	$41.55	5.25%	5.25%	3.50%	3.76%	4.44%	5.70%	65.00%	61.00%	69.45%	($0.00)	10.28%	15.18	2.66
												MEAN	9.96%		
												MAX	10.43%		
												MIN	9.24%		

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AGL Resources Inc.	GAS	$2.32	$2.46	$2.61	$2.77	$2.94	$3.12	$3.30	$3.50	$3.71	$3.92	$4.15	$4.39	$4.64	$4.90	$5.18	$5.48	$5.79
Atmos Energy Corp.	ATO	$2.10	$2.22	$2.35	$2.49	$2.63	$2.78	$2.94	$3.11	$3.29	$3.48	$3.68	$3.89	$4.11	$4.34	$4.59	$4.85	$5.13
Laclede Group, Inc.	LG	$2.79	$2.93	$3.08	$3.24	$3.41	$3.58	$3.77	$3.97	$4.18	$4.41	$4.66	$4.92	$5.21	$5.50	$5.82	$6.15	$6.50
New Jersey Resources	NJR	$2.71	$2.81	$2.92	$3.03	$3.15	$3.27	$3.40	$3.55	$3.72	$3.91	$4.12	$4.36	$4.60	$4.87	$5.14	$5.44	$5.75
Northwest Natural Gas	NWN	$2.22	$2.32	$2.42	$2.52	$2.63	$2.75	$2.87	$3.01	$3.16	$3.33	$3.51	$3.71	$3.92	$4.15	$4.38	$4.63	$4.90
Piedmont Natural Gas	PNY	$1.66	$1.72	$1.79	$1.86	$1.93	$2.00	$2.08	$2.17	$2.28	$2.39	$2.52	$2.67	$2.82	$2.98	$3.15	$3.33	$3.52
South Jersey Industries	SJI	$3.03	$3.26	$3.50	$3.76	$4.04	$4.35	$4.66	$4.98	$5.31	$5.64	$5.98	$6.32	$6.68	$7.07	$7.47	$7.89	$8.35
Southwest Gas Corp.	SWX	$2.86	$3.04	$3.23	$3.43	$3.64	$3.87	$4.11	$4.36	$4.62	$4.89	$5.17	$5.46	$5.78	$6.11	$6.45	$6.82	$7.21
WGL Holdings, Inc.	WGL	$2.68	$2.80	$2.92	$3.05	$3.19	$3.33	$3.48	$3.65	$3.84	$4.04	$4.26	$4.51	$4.76	$5.04	$5.32	$5.63	$5.95

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
AGL Resources Inc.	GAS	74.00%	68.00%	62.00%	56.00%	50.00%	53.24%	56.48%	59.73%	62.97%	66.21%	69.45%	69.45%	69.45%	69.45%	69.45%
Atmos Energy Corp.	ATO	57.00%	55.25%	53.50%	51.75%	50.00%	53.24%	56.48%	59.73%	62.97%	66.21%	69.45%	69.45%	69.45%	69.45%	69.45%
Laclede Group, Inc.	LG	61.00%	57.75%	54.50%	51.25%	48.00%	51.58%	55.15%	58.73%	62.30%	65.88%	69.45%	69.45%	69.45%	69.45%	69.45%
New Jersey Resources	NJR	61.00%	60.25%	59.50%	58.75%	58.00%	59.91%	61.82%	63.73%	65.63%	67.54%	69.45%	69.45%	69.45%	69.45%	69.45%
Northwest Natural Gas	NWN	80.00%	75.00%	70.00%	65.00%	60.00%	61.58%	63.15%	64.73%	66.30%	67.88%	69.45%	69.45%	69.45%	69.45%	69.45%
Piedmont Natural Gas	PNY	72.00%	72.00%	72.00%	72.00%	72.00%	71.58%	71.15%	70.73%	70.30%	69.88%	69.45%	69.45%	69.45%	69.45%	69.45%
South Jersey Industries	SJI	56.00%	55.00%	54.00%	53.00%	52.00%	54.91%	57.82%	60.73%	63.63%	66.54%	69.45%	69.45%	69.45%	69.45%	69.45%
Southwest Gas Corp.	SWX	44.00%	43.75%	43.50%	43.25%	43.00%	47.41%	51.82%	56.23%	60.63%	65.04%	69.45%	69.45%	69.45%	69.45%	69.45%
WGL Holdings, Inc.	WGL	65.00%	64.00%	63.00%	62.00%	61.00%	62.41%	63.82%	65.23%	66.63%	68.04%	69.45%	69.45%	69.45%	69.45%	69.45%

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
AGL Resources Inc.	GAS	$1.82	$1.78	$1.72	$1.65	$1.56	$1.76	$1.98	$2.21	$2.47	$2.75	$3.05	$3.22	$3.40	$3.60	$3.80	$91.69
Atmos Energy Corp.	ATO	$1.27	$1.30	$1.33	$1.36	$1.39	$1.57	$1.76	$1.97	$2.19	$2.44	$2.70	$2.85	$3.02	$3.19	$3.37	$87.96
Laclede Group, Inc.	LG	$1.79	$1.78	$1.77	$1.75	$1.72	$1.94	$2.19	$2.46	$2.75	$3.07	$3.42	$3.62	$3.82	$4.04	$4.27	$95.41
New Jersey Resources	NJR	$1.72	$1.76	$1.80	$1.85	$1.89	$2.04	$2.20	$2.37	$2.57	$2.78	$3.03	$3.20	$3.38	$3.57	$3.78	$95.50
Northwest Natural Gas	NWN	$1.85	$1.81	$1.77	$1.71	$1.65	$1.77	$1.90	$2.05	$2.21	$2.38	$2.58	$2.72	$2.88	$3.04	$3.22	$96.28
Piedmont Natural Gas	PNY	$1.24	$1.29	$1.34	$1.39	$1.44	$1.49	$1.55	$1.61	$1.68	$1.76	$1.85	$1.96	$2.07	$2.19	$2.31	$68.28
South Jersey Industries	SJI	$1.82	$1.93	$2.03	$2.14	$2.26	$2.56	$2.88	$3.22	$3.59	$3.98	$4.39	$4.64	$4.91	$5.19	$5.48	$124.67
Southwest Gas Corp.	SWX	$1.34	$1.41	$1.49	$1.58	$1.66	$1.95	$2.26	$2.59	$2.96	$3.36	$3.80	$4.01	$4.24	$4.48	$4.74	$107.83
WGL Holdings, Inc.	WGL	$1.82	$1.87	$1.92	$1.98	$2.03	$2.17	$2.33	$2.50	$2.69	$2.90	$3.13	$3.31	$3.50	$3.70	$3.91	$90.29

Projected Annual Data Investor Cash Flows		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	6/14/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
AGL Resources Inc.	GAS	($41.06)	$0.00	$1.00	$1.88	$1.72	$1.65	$1.56	$1.76	$1.98	$2.21	$2.47	$2.75	$3.05	$3.22	$3.40	$3.60	$95.50
Atmos Energy Corp.	ATO	($38.71)	$0.00	$0.69	$1.30	$1.33	$1.36	$1.39	$1.57	$1.76	$1.97	$2.19	$2.44	$2.70	$2.85	$3.02	$3.19	$91.33
Laclede Group, Inc.	LG	($41.99)	$0.00	$0.98	$1.83	$1.77	$1.75	$1.72	$1.94	$2.19	$2.46	$2.75	$3.07	$3.42	$3.62	$3.82	$4.04	$99.68
New Jersey Resources	NJR	($43.60)	$0.00	$0.94	$1.75	$1.80	$1.85	$1.89	$2.04	$2.20	$2.37	$2.57	$2.78	$3.03	$3.20	$3.38	$3.57	$99.27
Northwest Natural Gas	NWN	($44.92)	$0.00	$1.02	$1.89	$1.77	$1.71	$1.65	$1.77	$1.90	$2.05	$2.21	$2.38	$2.58	$2.72	$2.88	$3.04	$99.50
Piedmont Natural Gas	PNY	($32.48)	$0.00	$0.66	$1.26	$1.34	$1.39	$1.44	$1.49	$1.55	$1.61	$1.68	$1.76	$1.85	$1.96	$2.07	$2.19	$70.59
South Jersey Industries	SJI	($54.16)	$0.00	$1.00	$1.89	$2.03	$2.14	$2.26	$2.56	$2.88	$3.22	$3.59	$3.98	$4.39	$4.64	$4.91	$5.19	$130.16
Southwest Gas Corp.	SWX	($45.40)	$0.00	$0.73	$1.38	$1.49	$1.58	$1.66	$1.95	$2.26	$2.59	$2.96	$3.36	$3.80	$4.01	$4.24	$4.48	$112.57
WGL Holdings, Inc.	WGL	($41.55)	$0.00	$1.00	$1.86	$1.92	$1.98	$2.03	$2.17	$2.33	$2.50	$2.69	$2.90	$3.13	$3.31	$3.50	$3.70	$94.20

Multi-Stage DCF Notes:

[1] Source: Bloomberg; based on 30-, 90-, and 180-day historical average
[2] Source: Zacks
[3] Source: Yahoo! Finance
[4] Source: Value Line
[5] Source: Schedule (RBH-R)-3
[6] Equals average Columns [2], [3], [4], [5]
[7] Source: Federal Reserve, Bureau of Economic Analysis
[8] Source: Value Line
[9] Source: Value Line
[10] Source: Bloomberg Professional
[11] Equals Column [1] + Column [63]
[12] Equals result of Excel Solver function; goal: Column [11] equals $0.00
[13] Equals Column [62] / Column [31]
[14] Equals Column [13] / (Column [7] x 100)
[15] Source: Value Line
[16] Equals Column [15] x (1 + Column [6])
[17] Equals Column [16] x (1 + Column [6])
[18] Equals Column [17] x (1 + Column [6])
[19] Equals Column [18] x (1 + Column [6])
[20] Equals Column [19] x (1 + Column [6])
[21] Equals (1 + (Column [6] + (((Column [7] – Column [6]) / (2022 – 2017 + 1)) x (2018 – 2017)))) x Column [20]
[22] Equals (1 + (Column [6] + (((Column [7] – Column [6]) / (2022 – 2017 + 1)) x (2019 – 2017)))) x Column [21]
[23] Equals (1 + (Column [6] + (((Column [7] – Column [6]) / (2022 – 2017 + 1)) x (2020 – 2017)))) x Column [22]
[24] Equals (1 + (Column [6] + (((Column [7] – Column [6]) / (2022 – 2017 + 1)) x (2021 – 2017)))) x Column [23]
[25] Equals (1 + (Column [6] + (((Column [7] – Column [6]) / (2022 – 2017 + 1)) x (2022 – 2017)))) x Column [24]
[26] Equals Column [25] x (1 + Column [7])
[27] Equals Column [26] x (1 + Column [7])
[28] Equals Column [27] x (1 + Column [7])
[29] Equals Column [28] x (1 + Column [7])
[30] Equals Column [29] x (1 + Column [7])
[31] Equals Column [30] x (1 + Column [7])
[32] Equals Column [8]
[33] Equals Column [32] + ((Column [36] – Column [32]) / 4)
[34] Equals Column [33] + ((Column [36] – Column [32]) / 4)
[35] Equals Column [34] + ((Column [36] – Column [32]) / 4)
[36] Equals Column [9]
[37] Equals Column [36] + ((Column [42] – Column [36]) / 6)
[38] Equals Column [37] + ((Column [42] – Column [36]) / 6)
[39] Equals Column [38] + ((Column [42] – Column [36]) / 6)
[40] Equals Column [39] + ((Column [42] – Column [36]) / 6)
[41] Equals Column [40] + ((Column [42] – Column [36]) / 6)
[42] Equals Column [10]
[43] Equals Column [10]
[44] Equals Column [10]
[45] Equals Column [10]
[46] Equals Column [10]
[47] Equals Column [16] x Column [32]
[48] Equals Column [17] x Column [33]
[49] Equals Column [18] x Column [34]
[50] Equals Column [19] x Column [35]
[51] Equals Column [20] x Column [36]
[52] Equals Column [21] x Column [37]
[53] Equals Column [22] x Column [38]
[54] Equals Column [23] x Column [39]
[55] Equals Column [24] x Column [40]
[56] Equals Column [25] x Column [41]
[57] Equals Column [26] x Column [42]
[58] Equals Column [27] x Column [43]
[59] Equals Column [28] x Column [44]
[60] Equals Column [29] x Column [45]
[61] Equals Column [30] x Column [46]
[62] Equals (Column [61] x (1 + Column [7])) / (Column [12] – Column [7])
[63] Equals negative net present value; discount rate equals Column [12], cash flows equal Column [64] through Column [79]
[64] Equals $0.00
[65] Equals (12/31/2013 - 6/14/2013) x Column [47]
[66] Equals Column [47] x (1 + ((6/30/2014 -12/31/2013) / 365 x Column [6]))
[67] Equals Column [49]
[68] Equals Column [50]
[69] Equals Column [51]
[70] Equals Column [52]
[71] Equals Column [53]
[72] Equals Column [54]
[73] Equals Column [55]
[74] Equals Column [56]
[75] Equals Column [57]
[76] Equals Column [58]
[77] Equals Column [59]
[78] Equals Column [60]
[79] Equals Column [61] + [62]

Sharpe Ratio Derived *Ex-Ante* Market Risk Premium

[1]	[2]	[3]	[4]	[5]
RP_h	Vol_h	VOL_e	Historical Sharpe Ratio	RP_e
6.70%	20.18%	23.31%	33.19%	7.74%

Date	[6] Volatility
6/14/2013	25.03
6/13/2013	24.84
6/12/2013	25.37
6/11/2013	24.82
6/10/2013	24.28
6/7/2013	24.35
6/6/2013	24.66
6/5/2013	24.74
6/4/2013	24.37
6/3/2013	24.27
5/31/2013	24.21
5/30/2013	23.89
5/29/2013	23.78
5/28/2013	23.73
5/24/2013	23.92
5/23/2013	23.96
5/22/2013	23.85
5/21/2013	23.81
5/20/2013	23.56
5/17/2013	23.48
5/16/2013	23.62
5/15/2013	23.36
5/14/2013	23.16
5/13/2013	23.13
5/10/2013	20.42
5/9/2013	20.40
5/8/2013	19.88
5/7/2013	20.02
5/6/2013	20.13
5/3/2013	20.16
Average:	23.31

Notes:
[1] Source: Morningstar, Inc.
RP_h = historical arithmetic average Risk Premium
[2] Source: Morningstar, Inc.
Vol_h = historical market volatility
[3] Vol_e = expected market volatility (average of Col. [6])
[4] Equals [1] / [2]
[5] RP_e = expected Risk Premium ([3] x [4])
[6] Source: CBOE VIX Term Structure

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
13.07%	3.20%	9.88%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Equals [1] – [2]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
12.84%	3.20%	9.65%

Notes:
[1] Source: Value Line
[2] Source: Bloomberg Professional
[3] Equals [1] – [2]

Bloomberg and Value Line Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
AGL Resources Inc.	GAS	0.773	0.75
Atmos Energy Corporation	ATO	0.681	0.70
Laclede Group, Inc. (The)	LG	0.640	0.60
New Jersey Resources Corporation	NJR	0.759	0.65
Northwest Natural Gas Company	NWN	0.683	0.60
Piedmont Natural Gas Company, Inc.	PNY	0.832	0.65
South Jersey Industries, Inc.	SJI	0.776	0.65
Southwest Gas Corporation	SWX	0.778	0.75
WGL Holdings, Inc.	WGL	0.762	0.65
Mean		0.743	0.67

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Value Line

Capital Asset Pricing Model Results
Sharpe Ratio, Bloomberg, and Capital IQ Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Ex-Ante Market Risk Premium			CAPM Result		
	Risk-Free Rate	Average Beta Coefficient	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP BLOOMBERG BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	3.20%	0.743	7.74%	9.88%	9.65%	8.94%	10.53%	10.36%
Near-Term Projected 30-Year Treasury [10]	3.37%	0.743	7.74%	9.88%	9.65%	9.11%	10.70%	10.53%
Mean						9.03%	10.62%	10.45%

			Ex-Ante Market Risk Premium			CAPM Result		
	Risk-Free Rate	Average Beta Coefficient	Sharpe Ratio Derived	Bloomberg Market DCF Derived		Sharpe Ratio Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	3.20%	0.667	7.74%	9.88%	9.65%	8.35%	9.78%	9.63%
Near-Term Projected 30-Year Treasury [10]	3.37%	0.667	7.74%	9.88%	9.65%	8.52%	9.95%	9.80%
Mean						8.44%	9.87%	9.71%

Notes:
[1] *See Notes [9] and [10]*
[2] Source: Schedule (RBH)-6
[3] Source: Schedule (RBH)-5
[4] Source: Schedule (RBH)-5
[5] Source: Schedule (RBH)-5
[6] Equals Col. [1] + (Col. [2] x Col. [3])
[7] Equals Col. [1] + (Col. [2] x Col. [4])
[8] Equals Col. [1] + (Col. [2] x Col. [5])
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, at 2

Bond Yield Plus Risk Premium

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
Current	-3.18%	-2.93%	3.20%	6.90%	10.10%
Near Term Projected	-3.18%	-2.93%	3.37%	6.75%	10.12%
Long-Term Projected	-3.18%	-2.93%	5.40%	5.37%	10.77%

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 2,
Long Term Projected = Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14
[4] Equals [1] + [2] x ln([3])
[5] Equals [3] + [4]

Proof Concept: Perpetual DCF Results Equal Holding Period DCF Results With Terminal Value

Line Description	IMPLIED GROWTH RATE AT ALLOWED ROE:	
Input	Dividend Yield	3.56% [1]
Assumes g = Allowed ROE - Div. Yield	Assumed Growth Rate	5.32%
Input	Total Return	8.89% [1]
Input	Payout Ratio	80.00% [2]
Input	Book Value/Share	20 [2]

		0	1	2	3	4	5	6	7	8	9	10
BV/S Escalates at Constant Growth g	Book Value/Share	$ 20.00	$ 21.06	$ 22.19	$ 23.37	$ 24.61	$ 25.92	$ 27.30	$ 28.76	$ 30.29	$ 31.90	$ 33.60
Demonstrating Constant BV/S growth			5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Earnings based on ROE applied to BV/S	Earnings/share	$ 1.78	$ 1.87	$ 1.97	$ 2.08	$ 2.19	$ 2.30	$ 2.43	$ 2.56	$ 2.69	$ 2.83	$ 2.99
Demonstrating Constant EPS growth			5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Demonstrating Constant Return Earned based on BV/S and EPS	Allowed ROE	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
Div/S based on EPS and Constant Payout ratio	Dividends/Share	$ 1.42	$ 1.50	$ 1.58	$ 1.66	$ 1.75	$ 1.84	$ 1.94	$ 2.04	$ 2.15	$ 2.27	$ 2.39
Demonstrating Constant Div/S growth			5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Retained Earnings based on difference between EPS and Div/S	Earnings retained to book value	$ 0.36	$ 0.37	$ 0.39	$ 0.42	$ 0.44	$ 0.46	$ 0.49	$ 0.51	$ 0.54	$ 0.57	$ 0.60
Demonstrating Constant growth in Retained Earnings			5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Demonstrating Constant Market/Book ratio	Market/Book Ratio	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102
DCF calculation of market price = [Div/S]*[1+g]/[ROE-g]	Market Price	$ 42.05	$ 44.29	$ 46.65	$ 49.13	$ 51.75	$ 54.50	$ 57.40	$ 60.46	$ 63.68	$ 67.07	$ 70.64
Demonstrating Price Appreciation equals Long Term Growth Rate	Price Appreciation	5.32%	OK	<== Price appreciation should equal long term growth rate								
Demonstrating Constant Price/Earnings Ratio	Price/Earnings	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66
Present Value Factor calculated based upon the current period and the Constant ROE	Present Value Factor		0.9184	0.8434	0.7746	0.7114	0.6533	0.6000	0.5510	0.5061	0.4648	0.4268

CASE 1	DIVIDENDS IN PERPETUITY	1	2	3	4	5	6	7	8	9	10
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value Dividend	1.3753	1.3303	1.2868	1.2447	1.2040	1.1646	1.1265	1.0897	1.0541	1.0196
Total Value of investment sum of all Present Value Dividends in perpetuity (250 instances for demonstration purposes)	Value of Investment	$ 42.04									

CASE 2	10-YEAR HOLDING PERIOD	1	2	3	4	5	6	7	8	9	10
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value of Dividend	$ 1.38	$ 1.33	$ 1.29	$ 1.24	$ 1.20	$ 1.16	$ 1.13	$ 1.09	$ 1.05	$ 1.02
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value)	Present Value of Stock Price	–	–	–	–	–	–	–	–	–	30.15
Value of dividends = sum of all Present Value Dividends for periods 1-10	Value of Dividends	$ 11.90									
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value)	Value of Stock Price	$ 30.15									
Total Value of investment sum of all Present Value Dividends for periods 1-10 and Present Value of Stock in period 10 (Terminal Value)	Value of Investment	$ 42.05									

CASE 3	5-YEAR HOLDING PERIOD	1	2	3	4	5
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value of Dividend	$ 1.38	$ 1.33	$ 1.29	$ 1.24	$ 1.20
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value)	Present Value of Stock Price	–	–	–	–	35.61
Value of dividends = sum of all Present Value Dividends for periods 1-5	Value of Dividends	$ 6.44				
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value)	Value of Stock Price	$ 35.61				
Total Value of investment sum of all Present Value Dividends for periods 1-5 and Present Value of Stock in period 5 (Terminal Value)	Value of Investment	$ 42.05				

[1] Source: Schedule (RBH-R)-2. Note, for purposes of this exhibit, these data are illustrative only.
[2] Note: illustrative only.

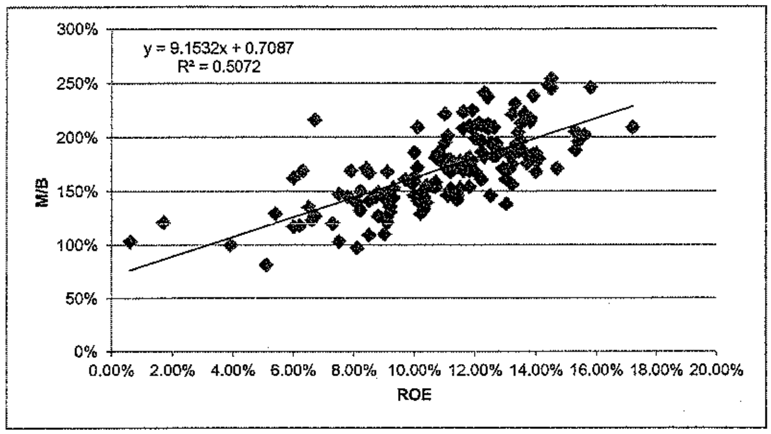
Proof Concept: Perpetual DCF Results Equal Holding Period DCF Results With Terminal Value

		90	91	92	93	94	95	96	97	98	99	100	250
BV/S Escalates at Constant Growth g	Book Value/Share	$ 2,132.19	$ 2,245.73	$ 2,365.31	$ 2,491.26	$ 2,623.92	$ 2,763.64	$ 2,910.80	$ 3,065.80	$ 3,229.05	$ 3,400.99	$ 3,582.09	$ 8,586,101.51
Demonstrating Constant BV/S growth		5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Earnings based on ROE applied to BV/S	Earnings/share	$ 189.47	$ 199.56	$ 210.19	$ 221.38	$ 233.17	$ 245.59	$ 258.66	$ 272.44	$ 286.94	$ 302.22	$ 318.32	$ 762,987.82
Demonstrating Constant EPS growth		5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Demonstrating Constant Return Earned based on BV/S and EPS	Allowed ROE	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
Div/S based on EPS and Constant Payout ratio	Dividends/Share	$ 151.58	$ 159.65	$ 168.15	$ 177.10	$ 186.54	$ 196.47	$ 206.93	$ 217.95	$ 229.55	$ 241.78	$ 254.65	$ 610,390.26
Demonstrating Constant Div/S growth		5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Retained Earnings based on difference between EPS and Div/S	Earnings retained to book value	$ 37.89	$ 39.91	$ 42.04	$ 44.28	$ 46.63	$ 49.12	$ 51.73	$ 54.49	$ 57.39	$ 60.44	$ 63.66	$ 152,597.56
Demonstrating Constant growth in Retained Earnings		5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%
Demonstrating Constant Market/Book ratio	Market/Book Ratio	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102	2.102
DCF calculation of market price = [Div/S]*[1+g]/[ROE-g]	Market Price	$ 4,482.77	$ 4,721.47	$ 4,972.89	$ 5,237.69	$ 5,516.59	$ 5,810.34	$ 6,119.74	$ 6,445.61	$ 6,788.83	$ 7,150.33	$ 7,531.08	$ 18,051,638.12
Demonstrating Price Appreciation equals Long Term Growth Rate	Price Appreciation												
Demonstrating Constant Price/Earnings Ratio	Price/Earnings	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66	23.66
Present Value Factor calculated based upon the current period and the Constant ROE	Present Value Factor	0.0005	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0000

CASE 1	DIVIDENDS IN PERPETUITY												
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value Dividend	0.0713	0.0690	0.0667	0.0645	0.0624	0.0604	0.0584	0.0565	0.0546	0.0529	0.0511	0.0003
Total Value of investment sum of all Present Value Dividends in perpetuity (250 instances for demonstration purposes)	Value of Investment												

Market-to-Book Regression Analysis
Parcell Proxy Group

Market to Book Ratio	Implied ROE
111%	4.38%
115%	4.82%
125%	5.91%
162%	10.00%
165%	10.25%
111%	**4.38%**



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.712201715
R Square	0.507231282
Adjusted R Square	0.503832877
Standard Error	0.245493652
Observations	147

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	8.995212648	8.9952126	149.255692	4.80514E-24
Residual	145	8.738734291	0.0602671		
Total	146	17.73394694			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.708718802	0.084503072	8.3868999	4.029E-14	0.541701898	0.875735705	0.541701898	0.875735705
ROE	9.153155007	0.749213106	12.217025	4.8051E-24	7.672365599	10.63394442	7.672365599	10.63394442

Market-to-Book Regression Analysis
Parcell Proxy Group

Company	Year	ROE	M/B
GAS	1992	11.80%	181.00%
GAS	1993	11.00%	195.00%
GAS	1994	11.60%	169.00%
GAS	1995	13.10%	172.00%
GAS	1996	13.20%	189.00%
GAS	1997	12.70%	183.00%
GAS	1998	12.60%	183.00%
GAS	1999	7.90%	169.00%
GAS	2000	11.20%	168.00%
GAS	2001	12.70%	184.00%
GAS	2002	14.70%	171.00%
GAS	2003	15.30%	188.00%
GAS	2004	13.90%	184.00%
GAS	2005	13.30%	191.00%
GAS	2006	13.60%	186.00%
GAS	2007	12.80%	188.00%
GAS	2008	12.50%	146.00%
GAS	2009	13.00%	138.00%
GAS	2010	13.00%	161.00%
GAS	2011	8.20%	150.00%
GAS	2012	8.10%	139.00%

Market-to-Book Regression Analysis
Parcell Proxy Group

Company	Year	ROE	M/B
ATO	1992	10.70%	158.00%
ATO	1993	12.70%	194.00%
ATO	1994	10.00%	186.00%
ATO	1995	12.20%	196.00%
ATO	1996	14.40%	248.00%
ATO	1997	12.30%	241.00%
ATO	1998	15.80%	246.00%
ATO	1999	6.70%	216.00%
ATO	2000	8.50%	167.00%
ATO	2001	11.10%	170.00%
ATO	2002	10.30%	150.00%
ATO	2003	11.20%	152.00%
ATO	2004	9.10%	147.00%
ATO	2005	9.10%	145.00%
ATO	2006	10.00%	146.00%
ATO	2007	9.20%	136.00%
ATO	2008	9.00%	110.00%
ATO	2009	8.50%	109.00%
ATO	2010	9.10%	121.00%
ATO	2011	9.20%	130.00%
ATO	2012	8.20%	132.00%
LG	1992	9.90%	158.00%
LG	1993	13.40%	187.00%
LG	1994	11.50%	178.00%
LG	1995	10.00%	163.00%
LG	1996	14.00%	168.00%
LG	1997	13.20%	175.00%
LG	1998	11.00%	174.00%
LG	1999	10.00%	159.00%
LG	2000	9.10%	141.00%
LG	2001	10.60%	155.00%
LG	2002	7.80%	145.00%
LG	2003	11.80%	169.00%
LG	2004	11.20%	179.00%
LG	2005	11.10%	179.00%
LG	2006	13.10%	184.00%
LG	2007	12.00%	168.00%
LG	2008	12.60%	209.00%
LG	2009	12.90%	171.00%
LG	2010	10.30%	145.00%
LG	2011	11.50%	153.00%
LG	2012	10.70%	154.00%
NWN	1992	6.00%	162.00%
NWN	1993	13.70%	176.00%
NWN	1994	12.20%	161.00%
NWN	1995	11.40%	146.00%
NWN	1996	13.20%	156.00%
NWN	1997	11.20%	173.00%
NWN	1998	6.30%	169.00%
NWN	1999	10.10%	141.00%
NWN	2000	10.20%	129.00%
NWN	2001	10.30%	133.00%
NWN	2002	8.70%	145.00%
NWN	2003	9.20%	144.00%
NWN	2004	9.30%	153.00%
NWN	2005	10.10%	172.00%
NWN	2006	10.90%	177.00%
NWN	2007	12.40%	208.00%
NWN	2008	11.10%	201.00%
NWN	2009	11.60%	173.00%
NWN	2010	10.70%	181.00%
NWN	2011	9.10%	168.00%
NWN	2012	8.40%	171.00%

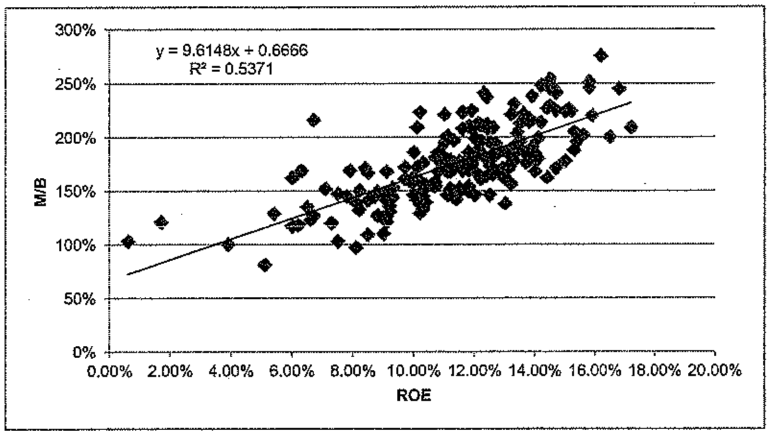
Market-to-Book Regression Analysis
Parcell Proxy Group

Company	Year	ROE	M/B
PNY	1992	14.10%	180.00%
PNY	1993	13.80%	214.00%
PNY	1994	12.20%	186.00%
PNY	1995	12.30%	182.00%
PNY	1996	13.20%	183.00%
PNY	1997	13.80%	217.00%
PNY	1998	13.60%	222.00%
PNY	1999	12.10%	213.00%
PNY	2000	12.50%	195.00%
PNY	2001	12.00%	199.00%
PNY	2002	10.80%	186.00%
PNY	2003	12.20%	211.00%
PNY	2004	12.40%	212.00%
PNY	2005	11.60%	208.00%
PNY	2006	11.00%	221.00%
PNY	2007	11.80%	210.00%
PNY	2008	12.40%	237.00%
PNY	2009	13.50%	213.00%
PNY	2010	11.90%	208.00%
PNY	2011	11.60%	223.00%
PNY	2012	11.90%	225.00%
SJI	1992	11.80%	154.00%
SJI	1993	11.00%	175.00%
SJI	1994	8.50%	141.00%
SJI	1995	11.40%	142.00%
SJI	1996	11.10%	146.00%
SJI	1997	11.90%	178.00%
SJI	1998	10.10%	209.00%
SJI	1999	15.60%	202.00%
SJI	2000	15.40%	196.00%
SJI	2001	15.30%	205.00%
SJI	2002	14.00%	185.00%
SJI	2003	13.10%	170.00%
SJI	2004	13.40%	195.00%
SJI	2005	13.20%	221.00%
SJI	2006	17.20%	209.00%
SJI	2007	13.30%	231.00%
SJI	2008	13.50%	196.00%
SJI	2009	13.40%	204.00%
SJI	2010	14.50%	245.00%
SJI	2011	14.50%	254.00%
SJI	2012	13.90%	238.00%
SWX	1992	5.10%	81.00%
SWX	1993	3.90%	100.00%
SWX	1994	7.50%	103.00%
SWX	1995	0.60%	103.00%
SWX	1996	1.70%	121.00%
SWX	1997	5.40%	129.00%
SWX	1998	10.40%	139.00%
SWX	1999	7.50%	147.00%
SWX	2000	7.30%	120.00%
SWX	2001	6.70%	127.00%
SWX	2002	6.60%	123.00%
SWX	2003	6.20%	118.00%
SWX	2004	8.80%	127.00%
SWX	2005	6.50%	135.00%
SWX	2006	9.70%	161.00%
SWX	2007	8.80%	149.00%
SWX	2008	6.00%	117.00%
SWX	2009	8.10%	97.00%
SWX	2010	9.10%	127.00%
SWX	2011	9.30%	144.00%
SWX	2012	10.40%	155.00%

Source: Exhibit DCP-1, Schedule 10

Market-to-Book Regression Analysis
Hevert Proxy Group

Market to Book Ratio	Implied ROE
111%	4.61%
115%	5.03%
125%	6.07%
163%	10.00%
165%	10.25%
111%	**4.61%**



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.732879523
R Square	0.537112395
Adjusted R Square	0.53463706
Standard Error	0.244486371
Observations	189

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	12.97001676	12.970017	216.985758	4.17265E-33
Residual	187	11.17766049	0.0597736		
Total	188	24.14767725			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.666628686	0.076622952	8.7001175	1.6945E-15	0.515472211	0.817785161	0.515472211	0.817785161
ROE	9.614808319	0.652717138	14.730436	4.1726E-33	8.327172965	10.90244367	8.327172965	10.90244367

Market-to-Book Regression Analysis
Hevert Proxy Group

Company	Year	ROE	M/B
GAS	1992	11.80%	181.00%
GAS	1993	11.00%	195.00%
GAS	1994	11.60%	169.00%
GAS	1995	13.10%	172.00%
GAS	1996	13.20%	189.00%
GAS	1997	12.70%	183.00%
GAS	1998	12.60%	183.00%
GAS	1999	7.90%	169.00%
GAS	2000	11.20%	168.00%
GAS	2001	12.70%	184.00%
GAS	2002	14.70%	171.00%
GAS	2003	15.30%	188.00%
GAS	2004	13.90%	184.00%
GAS	2005	13.30%	191.00%
GAS	2006	13.60%	186.00%
GAS	2007	12.80%	188.00%
GAS	2008	12.50%	146.00%
GAS	2009	13.00%	138.00%
GAS	2010	13.00%	161.00%
GAS	2011	8.20%	150.00%
GAS	2012	8.10%	139.00%

Market-to-Book Regression Analysis
Hevert Proxy Group

Company	Year	ROE	M/B
ATO	1992	10.70%	158.00%
ATO	1993	12.70%	194.00%
ATO	1994	10.00%	186.00%
ATO	1995	12.20%	196.00%
ATO	1996	14.40%	248.00%
ATO	1997	12.30%	241.00%
ATO	1998	15.80%	246.00%
ATO	1999	6.70%	216.00%
ATO	2000	8.50%	167.00%
ATO	2001	11.10%	170.00%
ATO	2002	10.30%	150.00%
ATO	2003	11.20%	152.00%
ATO	2004	9.10%	147.00%
ATO	2005	9.10%	145.00%
ATO	2006	10.00%	146.00%
ATO	2007	9.20%	136.00%
ATO	2008	9.00%	110.00%
ATO	2009	8.50%	109.00%
ATO	2010	9.10%	121.00%
ATO	2011	9.20%	130.00%
ATO	2012	8.20%	132.00%
LG	1992	9.90%	158.00%
LG	1993	13.40%	187.00%
LG	1994	11.50%	178.00%
LG	1995	10.00%	163.00%
LG	1996	14.00%	168.00%
LG	1997	13.20%	175.00%
LG	1998	11.00%	174.00%
LG	1999	10.00%	159.00%
LG	2000	9.10%	141.00%
LG	2001	10.60%	155.00%
LG	2002	7.80%	145.00%
LG	2003	11.80%	169.00%
LG	2004	11.20%	179.00%
LG	2005	11.10%	179.00%
LG	2006	13.10%	184.00%
LG	2007	12.00%	168.00%
LG	2008	12.60%	209.00%
LG	2009	12.90%	171.00%
LG	2010	10.30%	145.00%
LG	2011	11.50%	153.00%
LG	2012	10.70%	154.00%
NJR	1992	12.20%	161.00%
NJR	1993	11.80%	186.00%
NJR	1994	13.00%	162.00%
NJR	1995	13.30%	178.00%
NJR	1996	13.90%	191.00%
NJR	1997	14.50%	229.00%
NJR	1998	14.70%	225.00%
NJR	1999	15.00%	224.00%
NJR	2000	15.10%	226.00%
NJR	2001	15.20%	224.00%
NJR	2002	15.90%	220.00%
NJR	2003	16.80%	245.00%
NJR	2004	15.80%	251.00%
NJR	2005	16.20%	275.00%
NJR	2006	14.60%	246.00%
NJR	2007	10.20%	223.00%
NJR	2008	16.50%	200.00%
NJR	2009	14.20%	214.00%
NJR	2010	14.40%	227.00%
NJR	2011	14.20%	248.00%
NJR	2012	14.70%	241.00%

Market-to-Book Regression Analysis
Hevert Proxy Group

Company	Year	ROE	M/B
NWN	1992	6.00%	162.00%
NWN	1993	13.70%	176.00%
NWN	1994	12.20%	161.00%
NWN	1995	11.40%	146.00%
NWN	1996	13.20%	156.00%
NWN	1997	11.20%	173.00%
NWN	1998	6.30%	169.00%
NWN	1999	10.10%	141.00%
NWN	2000	10.20%	129.00%
NWN	2001	10.30%	133.00%
NWN	2002	8.70%	145.00%
NWN	2003	9.20%	144.00%
NWN	2004	9.30%	153.00%
NWN	2005	10.10%	172.00%
NWN	2006	10.90%	177.00%
NWN	2007	12.40%	208.00%
NWN	2008	11.10%	201.00%
NWN	2009	11.60%	173.00%
NWN	2010	10.70%	181.00%
NWN	2011	9.10%	168.00%
NWN	2012	8.40%	171.00%
PNY	1992	14.10%	180.00%
PNY	1993	13.80%	214.00%
PNY	1994	12.20%	186.00%
PNY	1995	12.30%	182.00%
PNY	1996	13.20%	183.00%
PNY	1997	13.80%	217.00%
PNY	1998	13.60%	222.00%
PNY	1999	12.10%	213.00%
PNY	2000	12.50%	195.00%
PNY	2001	12.00%	199.00%
PNY	2002	10.80%	186.00%
PNY	2003	12.20%	211.00%
PNY	2004	12.40%	212.00%
PNY	2005	11.60%	208.00%
PNY	2006	11.00%	221.00%
PNY	2007	11.80%	210.00%
PNY	2008	12.40%	237.00%
PNY	2009	13.50%	213.00%
PNY	2010	11.90%	208.00%
PNY	2011	11.60%	223.00%
PNY	2012	11.90%	225.00%
SJI	1992	11.80%	154.00%
SJI	1993	11.00%	175.00%
SJI	1994	8.50%	141.00%
SJI	1995	11.40%	142.00%
SJI	1996	11.10%	146.00%
SJI	1997	11.90%	178.00%
SJI	1998	10.10%	209.00%
SJI	1999	15.60%	202.00%
SJI	2000	15.40%	196.00%
SJI	2001	15.30%	205.00%
SJI	2002	14.00%	185.00%
SJI	2003	13.10%	170.00%
SJI	2004	13.40%	195.00%
SJI	2005	13.20%	221.00%
SJI	2006	17.20%	209.00%
SJI	2007	13.30%	231.00%
SJI	2008	13.50%	196.00%
SJI	2009	13.40%	204.00%
SJI	2010	14.50%	245.00%
SJI	2011	14.50%	254.00%
SJI	2012	13.90%	238.00%

Annual Earnings Surprise

Company	Ticker	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average
AGL Resources Inc.	GAS	-29.81%	-6.72%	14.98%	15.35%	3.19%	-1.05%	2.31%	6.47%	2.07%	0.86%	-0.65%	**0.64%**
Atmos Energy Corporation	ATO	0.69%	12.28%	1.41%	0.76%	8.46%	0.52%	1.06%	-11.31%	1.20%	3.36%	-6.97%	**1.04%**
Laclede Group, Inc. (The)	LG	-2.07%	6.25%	-4.56%	0.69%	11.11%	6.45%	4.31%	-0.58%	5.88%	-2.11%	5.36%	**2.79%**
New Jersey Resources Corporation	NJR	-1.32%	0.42%	-1.68%	-0.86%	2.00%	0.48%	1.37%	-73.09%	-2.46%	-0.77%	-0.37%	**-6.93%**
Northwest Natural Gas Company	NWN	2.36%	0.40%	2.76%	-3.03%	3.25%	0.04%	2.23%	2.06%	0.37%	2.44%	-11.15%	**0.16%**
Piedmont Natural Gas Company, Inc.	PNY	-1.66%	3.26%	8.04%	3.86%	-2.22%	-4.11%	-3.87%	5.50%	23.74%	0.00%	2.60%	**3.19%**
South Jersey Industries, Inc.	SJI	0.16%	3.96%	4.50%	-2.29%	1.37%	1.36%	-1.30%	0.63%	3.85%	4.44%	-4.20%	**1.13%**
Southwest Gas Corporation	SWX	-17.32%	-5.68%	6.67%	-15.24%	-2.94%	-6.70%	-23.71%	1.36%	3.56%	8.53%	6.80%	**-4.06%**
WGL Holdings, Inc.	WGL	-32.55%	4.92%	8.02%	8.32%	4.58%	1.08%	3.61%	2.76%	-1.05%	4.51%	6.22%	**0.95%**
Average		-9.06%	2.12%	4.46%	0.84%	3.20%	-0.21%	-1.55%	-7.36%	4.13%	2.36%	-0.26%	**-0.12%**

Number of Over-Estimates	34
Number of Under-Estimates	64
Number of Exact Estimates	1

Notes:
Source: Bloomberg Professional
The year represents the fiscal year.

Woolridge Growth Rate Specific DCF Analysis

Company	Ticker	Value Line EPS	Value Line Projected DPS	Value Line BVPS	Yahoo EPS	Zacks Projected EPS	Reuters EPS
AGL Resources Inc.	GAS	9.00%	2.00%	5.00%	NA	3.50%	3.80%
Atmos Energy Corporation	ATO	5.50%	1.50%	5.50%	6.00%	6.00%	6.00%
Laclede Group, Inc. (The)	LG	5.50%	2.00%	5.50%	5.30%	3.00%	NA
Northwest Natural Gas Company	NWN	3.00%	2.50%	1.00%	4.50%	3.80%	3.80%
Piedmont Natural Gas Company, Inc.	PNY	3.00%	3.00%	4.00%	5.00%	4.30%	5.00%
South Jersey Industries, Inc.	SJI	9.00%	9.00%	7.00%	6.00%	6.00%	NA
Southwest Gas Corporation	SWX	8.00%	7.00%	5.00%	6.00%	4.80%	6.00%
WGL Holdings, Inc.	WGL	2.00%	3.00%	3.50%	5.30%	5.30%	5.30%
Average		5.63%	3.75%	4.56%	5.44%	4.59%	4.98%
Dividend Yield		3.75%	3.75%	3.75%	3.75%	3.75%	3.75%
Adjusted Dividend Yield		3.86%	3.82%	3.84%	3.85%	3.84%	3.84%
Equity Cost Rate		**9.48%**	**7.57%**	**8.40%**	**9.29%**	**8.42%**	**8.83%**

Source: Exhibit JRW-10

Flotation Cost Adjustment

Two most recent open market common stock issuances per company, if available

Company	Date	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
Pepco Holdings, Inc	3/5/2012	17,922,077	$19.25	$0.6738	$500,000	$18.55	$12,574,999	$344,999,982	$332,424,983	3.645%
Pepco Holdings, Inc	11/5/2008	16,100,000	$16.50	$0.6188	$200,000	$15.87	$10,161,875	$265,650,000	$255,488,125	3.825%
AGL Resources Inc.	11/19/2004	11,040,000	$31.01	$0.9300	$400,000	$30.04	$10,667,200	$342,350,400	$331,683,200	3.116%
AGL Resources Inc.	2/11/2003	6,440,000	$22.00	$0.7700	$250,000	$21.19	$5,208,800	$141,680,000	$136,471,200	3.676%
Atmos Energy Corporation	12/7/2006	6,325,000	$31.50	$1.1025	$400,000	$30.33	$7,373,313	$199,237,500	$191,864,188	3.701%
Atmos Energy Corporation	10/21/2004	16,100,000	$24.75	$0.9900	$400,000	$23.74	$16,339,000	$398,475,000	$382,136,000	4.100%
Laclede Group, Inc. (The)	5/25/2004	1,725,000	$26.80	$0.8710	$100,000	$25.87	$1,602,475	$46,230,000	$44,627,525	3.466%
Laclede Group, Inc. (The)	5/22/2013	10,005,000	$44.50	$1.7244	$1,000,000	$42.68	$18,252,372	$445,222,500	$426,970,128	4.100%
Northwest Natural Gas Company	3/30/2004	1,290,000	$31.00	$1.0100	$175,000	$29.85	$1,477,900	$39,990,000	$38,512,100	3.696%
Piedmont Natural Gas Company, Inc.	1/20/2004	4,887,500	$42.50	$1.4900	$350,000	$40.94	$7,632,375	$207,718,750	$200,086,375	3.674%
Piedmont Natural Gas Company, Inc.	1/29/2013	4,600,000	$32.00	$1.1200	$350,000	$30.80	$5,502,000	$147,200,000	$141,698,000	3.738%
WGL Holdings, Inc.	6/20/2001	2,058,500	$26.73	$0.8950	$56,218	$25.81	$1,898,576	$55,023,705	$53,125,130	3.450%
Mean							$8,224,240	$219,481,486		
							WEIGHTED AVERAGE FLOTATION COSTS:			3.747%

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
					Expected Dividend Yield								
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Current	Adjusted for Flot. Costs	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Sustainable Growth	Average Earnings Growth	DCF k(e)	Flotation Adjusted DCF k(e)
AGL Resources Inc.	GAS	$1.88	$43.06	4.37%	4.50%	4.67%	3.53%	NA	9.00%	5.71%	6.08%	10.58%	10.75%
Atmos Energy Corporation	ATO	$1.40	$43.00	3.26%	3.35%	3.48%	6.00%	6.00%	5.50%	5.65%	5.79%	9.14%	9.27%
Laclede Group, Inc. (The)	LG	$1.70	$46.34	3.67%	3.76%	3.91%	3.00%	4.80%	5.50%	7.15%	5.11%	8.88%	9.02%
New Jersey Resources Corporation	NJR	$1.60	$45.69	3.50%	3.57%	3.71%	4.00%	4.00%	2.00%	5.23%	3.81%	7.38%	7.52%
Northwest Natural Gas Company	NWN	$1.82	$43.97	4.14%	4.23%	4.39%	3.83%	3.75%	5.00%	4.83%	4.35%	8.58%	8.75%
Piedmont Natural Gas Company, Inc.	PNY	$1.24	$34.15	3.63%	3.70%	3.84%	4.30%	5.00%	3.00%	2.90%	3.80%	7.50%	7.64%
South Jersey Industries, Inc.	SJI	$1.77	$59.13	2.99%	3.11%	3.23%	6.00%	6.00%	8.00%	9.95%	7.49%	10.59%	10.71%
Southwest Gas Corporation	SWX	$1.32	$49.10	2.69%	2.77%	2.88%	5.25%	6.00%	7.00%	6.67%	6.23%	9.00%	9.11%
WGL Holdings, Inc.	WGL	$1.68	$44.13	3.81%	3.89%	4.04%	5.25%	5.25%	3.50%	3.76%	4.44%	8.33%	8.48%
PROXY GROUP MEAN												8.89%	9.03%

DCF Result Adjusted For Flotation Costs:	9.03%
DCF Result Unadjusted For Flotation Costs:	8.89%
Difference (Flotation Cost Adjustment):	$\boxed{0.14\%}$ [13]

Notes:
The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (1 - flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Equals [4] / (1 - 0.0374)
[6] Source: Zacks
[7] Source: Yahoo! Finance
[8] Source: Value Line
[9] Source: Schedule (RBH)-3
[10] Equals Average([6], [7], [8], [9])
[11] Equals [4] + [10]
[12] Equals [5] + [10]
[13] Equals average [12] - average [11]

Flotation Cost Adjustment Example [1]

Issue Price	$ 100.00	[2]
Flotation Cost	5.00%	[3]
Dividend Yield	6.00%	[4]
Growth	5.00%	[5]
ROE	11.00%	[6]
Flotation Cost Adjusted ROE	11.32%	[7]

Company Earns Flotation Cost Adjusted ROE

Year	[8] Common Stock	[9] Retained Earnings	[10] Total Equity	[11] Stock Price	[12] Market / Book	[13] EPS	[14] DPS	[15] Payout Ratio	[16] Earned ROE
1	$ 95.00	$ -	$ 95.000	$ 100.000	1.0526	$ 10.750	$ 6.000	55.81%	
2	$ 95.00	$ 4.750	$ 99.750	$ 105.000	1.0526	$ 11.288	$ 6.300	55.81%	11.00%
3	$ 95.00	$ 9.738	$ 104.738	$ 110.250	1.0526	$ 11.852	$ 6.615	55.81%	11.00%
4	$ 95.00	$ 14.974	$ 109.974	$ 115.763	1.0526	$ 12.444	$ 6.946	55.81%	11.00%
5	$ 95.00	$ 20.473	$ 115.473	$ 121.551	1.0526	$ 13.067	$ 7.293	55.81%	11.00%
6	$ 95.00	$ 26.247	$ 121.247	$ 127.628	1.0526	$ 13.720	$ 7.658	55.81%	11.00%
7	$ 95.00	$ 32.309	$ 127.309	$ 134.010	1.0526	$ 14.406	$ 8.041	55.81%	11.00%
8	$ 95.00	$ 38.675	$ 133.675	$ 140.710	1.0526	$ 15.126	$ 8.443	55.81%	11.00%
9	$ 95.00	$ 45.358	$ 140.358	$ 147.746	1.0526	$ 15.883	$ 8.865	55.81%	11.00%
10	$ 95.00	$ 52.376	$ 147.376	$ 155.133	1.0526	$ 16.677	$ 9.308	55.81%	11.00%
Growth Rate [17]			5.00%	5.00%		5.00%	5.00%		

Company Does Not Earn Flotation Cost Adjusted ROE

Year	[8] Common Stock	[9] Retained Earnings	[10] Total Equity	[11] Stock Price	[12] Market / Book	[18] EPS	[19] DPS	[20] Payout Ratio	[21] Earned ROE
1	$ 95.00	$ -	$ 95.000	$ 100.000	1.0526	$ 10.450	$ 6.000	57.42%	
2	$ 95.00	$ 4.450	$ 99.450	$ 104.684	1.0526	$ 10.940	$ 6.281	57.42%	10.68%
3	$ 95.00	$ 9.108	$ 104.108	$ 109.588	1.0526	$ 11.452	$ 6.575	57.42%	10.68%
4	$ 95.00	$ 13.985	$ 108.985	$ 114.721	1.0526	$ 11.988	$ 6.883	57.42%	10.68%
5	$ 95.00	$ 19.090	$ 114.090	$ 120.095	1.0526	$ 12.550	$ 7.206	57.42%	10.68%
6	$ 95.00	$ 24.434	$ 119.434	$ 125.720	1.0526	$ 13.138	$ 7.543	57.42%	10.68%
7	$ 95.00	$ 30.029	$ 125.029	$ 131.609	1.0526	$ 13.753	$ 7.897	57.42%	10.68%
8	$ 95.00	$ 35.886	$ 130.886	$ 137.774	1.0526	$ 14.397	$ 8.266	57.42%	10.68%
9	$ 95.00	$ 42.017	$ 137.017	$ 144.228	1.0526	$ 15.072	$ 8.654	57.42%	10.68%
10	$ 95.00	$ 48.435	$ 143.435	$ 150.984	1.0526	$ 15.778	$ 9.059	57.42%	10.68%
Growth Rate [17]			4.68%	4.68%		4.68%	4.68%		

Notes:

[1] Exhibit is based on an analysis presented in New Regulatory Finance, Roger A. Morin, PhD, at 331-332
[2] Example for illustrative purposes only
[3] Example for illustrative purposes only
[4] Example for illustrative purposes only
[5] Example for illustrative purposes only
[6] Row [4] + Row [5]
[7] Row [4] / (1 - Row [3]) + Row [5]
[8] Row [2] - (Row [2] x Row [3])
[9] $Year_1$ = 0; $Year_{2 \text{ through } 10}$ = $Year_{n-1}$ (Col [13] - Col [14] + Col [9]); $Year_{2 \text{ through } 10}$ = $Year_{n-1}$ (Col [18] - Col [19] + Col [9])
[10] $Year_1$ = Col [8] + Col [9]; $Year_{2 \text{ through } 10}$ = $Year_{n-1}$ (Col [13] - Col [14] + Col [10]); $Year_{2 \text{ through } 10}$ = $Year_{n-1}$ (Col [18] - Col [19] + Col [10])
[11] $Year_1$ = Row [2]; $Year_{2 \text{ through } 10}$ = Col [14] / (Row [6] - Row [5]); $Year_{2 \text{ through } 10}$ = Col [19] / (Row [6] - Row [5])
[12] Col [11] / Col [10]
[13] Col [10] x Row [7]
[14] $Year_1$ = Row [2] x Row [4]; $Year_{2 \text{ through } 10}$ = $Year_{n-1}$ (Col [14] x (1 + Row [5])
[15] Col [14] / Col [13]
[16] Col [14] / Col [11] + [17]
[17] (Year 10 / Year 1)^(1/9) - 1
[18] Row [6] x Col [10]
[19] $Year_1$ = Row [2] x Row [4]; $Year_{2 \text{ through} 10}$ = Col [18] x $Year_{n-1}$ (Col [20])
[20] Col [19] / Col [18]
[21] Col [19] / Col [11] + [17]

Regulated Operations of the Proxy Companies

Company	Ticker	Revenue	Operating Income
AGL Resources Inc.	GAS	68.21%	82.54%
Atmos Energy Corp.	ATO	65.62%	94.49%
Laclede Group, Inc.	LG	58.24%	72.32%
New Jersey Resources	NJR	32.01%	88.35%
Northwest Natural Gas	NWN	97.52%	99.96%
Piedmont Natural Gas	PNY	100.00%	99.73%
South Jersey Industries	SJI	53.65%	84.96%
Southwest Gas Corp.	SWX	75.18%	89.05%
WGL Holdings, Inc.	WGL	47.51%	80.96%
3-Year Average (2010-2012)		66.44%	88.04%

Source: SNL Financial

Rebuttal Testimony of
Jay C. Ziminsky

DELMARVA POWER & LIGHT COMPANY

BEFORE THE DELAWARE PUBLIC SERVICE COMMMISSION REBUTTAL TESTIMONY OF JAY C. ZIMINSKY DOCKET NO. 12-546

Q1. Please state your name and position.

A1. My name is Jay C. Ziminsky. I am Manager, Revenue Requirements, in the Regulatory Affairs Department of Pepco Holdings, Inc. (PHI). I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What is the purpose of your Rebuttal Testimony?

A2. The purpose of my testimony is to address certain of the recommendations proposed by Division of Public Advocate (DPA) Witness Glenn Watkins and Staff Witnesses David Peterson and Gary Cohen in their direct testimonies. My Rebuttal Testimony also identifies those adjustments proposed by the Company that are uncontested and those that are contested. With respect to the contested adjustments, I will provide the Company's rebuttal to the positions offered by DPA and Staff. I also will address new adjustments offered by DPA and Staff as well as recommendations by these parties related to the Company's proposed Advanced Metering Infrastructure (AMI) Regulatory Asset recovery plan. Finally, I offer two corrections to the Company's revenue requirement that were learned during the discovery process as well as revisions to the post-test period reliability plant adjustments, Bloom rate base adjustment and AMI plant additions to the account for the fact that the Company currently is in a net operating loss carryforward (NOLC) position.

This Rebuttal Testimony was prepared by me or under my supervision and control. The source documents for my testimony are Company records, public documents, and my personal knowledge and experience.

Uncontested Adjustments Summary

Q3. Could you identify those adjustments that are uncontested by the parties?

A3. Yes. As detailed on page 1 of Schedule (JCZ-R)-1, the adjustment proposed by the Company that are uncontested are:

- Adjustment No. 1 – Remove Employee Association Dues,
- Adjustment No. 4 – Remove Executive Incentive Compensation,
- Adjustment No. 5 – Remove Certain Executive Compensation,
- Adjustment No. 6 – Normalize Uncollectible Expense,
- Adjustment No. 7 – Normalize Injuries & Damages Expense,
- Adjustment No. 10 – Remove Bloom-Related Incremental Rate Base,
- Adjustment No. 13 – Amortize Refinancing Losses,
- Adjustment No. 14 – Remove Post 1980 Investment Tax Credit Amortization,
- Adjustment No. 16 – Reflect Taxes Related to Medicare Part D Subsidy, and
- Adjustment No. 18 - Interest Synchronization (in concept).

It is important to provide explicit recognition of the ratemaking practices and adjustments that have been made and accepted in this proceeding. Explicit recognition of these uncontested adjustments allows the Company and other parties to use historical guidance in the preparation of future cases.

Contested Adjustments Summary

Q4. Can you identify your proposed adjustments that are contested by the parties?

A4. Yes, I can. The adjustments proposed in my Direct Testimony that are contested by the parties, each of which will be addressed separately below, include:

a) Adjustment No. 2 - Normalize Regulatory Commission Expense,
b) Adjustment No. 3 - Wage and FICA Adjustment,
c) Adjustment No. 8 - Employee Benefits Expense,
d) Adjustment No. 9 - Actual Reliability Plant Closings January 2013 to June 2013,
e) Adjustment No. 9a - Forecasted Reliability Plant Closings July 2013 to December 2013,
f) Adjustment No. 11 - Reflect Gas AMI Net Plant Additions
g) Adjustment No. 12 - Normalize Meter Reading Expense, and
h) Adjustment No. 19 - Reflect Cash Working Capital (CWC) Relating to all Pro-forma Adjustments.

In addition, Company Witness McGowan addresses Adjustment No. 15 – Recover Credit Facilities Expense.

Summary of Adjustments Proposed by the Other Parties

Q5. You stated earlier that there were new adjustments recommended by other parties in their direct testimonies. Can you identify the adjustments proposed by the other parties?

A5. DPA and Staff each have proposed additional adjustments to the Company's test period levels of rate base and expenses. The Company contests these adjustments and I will address each below. The adjustments being proposed by the other parties include:

a) Inclusion of Year-End Rate Base (Staff - In tandem with the contesting of the use of year-end rate base, Adjustment No. 17 – Annualization of Depreciation on Year-End Plant Balances, also becomes contested. DPA contests the use of year-end rate base relating to AMI);

b) Exclusion of Construction Work in Progress (CWIP) and Allowance for Funds used during Construction (AFUDC) in cost of service (Staff, DPA);

c) Remove Certain Portions of Non-Executive Incentive Expense (Staff, DPA); and

d) Capitalize Certain Portions of Salary Expense (Staff).

In addition, Company Witness Santacecilia addresses ratemaking adjustments proposed by the other parties that impact the Company's overall revenue requirement by adjusting revenue related to customer counts and growth (Staff, DPA).

AMI Regulatory Asset Recovery Plan Summary

Q6. Did you propose a recovery proposal for the Company's gas-related AMI regulatory asset costs in your Direct Testimony and did the other parties make different proposals?

A6. Yes. I proposed that the recovery of the regulatory asset begin upon demonstration by Delmarva that it is successfully reading at least 95% of eligible natural gas meters remotely through the Interface Management Units (IMU), which at this time is expected to be completed by or before a decision in this case is rendered. Similar to the process agreed upon in the settlement in Docket No. 11-528, under the

Company's proposal, the other parties would have a 60-day period for discovery to review the regulatory asset balances as well as the successful achievement of remote meter reading. The Company proposal calls for recovery of the AMI regulatory asset balance to begin once the Company is successfully remotely reading at least 95% of eligible natural gas meters. The Company proposes to recover the balance of the AMI regulatory asset over a 15-year period, with the unamortized balance included in rate base. This recovery proposal is similar to AMI-related regulatory assets approved in Docket Nos. 09-414, 10-237 and 11-528.

Staff and DPA each oppose the Company's recovery proposal and offer alternative proposals. I will address the criticisms leveled against the Company's proposal and provide the Company's position related to the Staff and DPA positions later in the AMI section of this testimony.

Q7. Have you quantified the revenue requirement based on the Company's position as described in its Rebuttal Testimony?

A7. Yes. I have quantified the revenue requirement of the Company's rebuttal positions. I have prepared Schedule (JCZ-R)-1 to compare the various parties' positions on all of the issues and the respective resulting revenue requirements. On Schedule (JCZ-R)-1, Pages 1 and 2, I have identified uncontested and contested items to better highlight the positions. For the Company's rebuttal position, its proposed revenue requirement is $12.067 million as shown on Schedule (JCZ-R)-1, Page 3.

Q8. Please provide an overall comment on the revenue changes recommended by the Staff and DPA.

A8. As Company Witness McGowan discusses in his Rebuttal Testimony, Staff's and the DPA's recommendations, if adopted, would have a negative effect on the Company and its customers. If adopted, these proposals likely would be viewed negatively by both the financial community and rating agencies. Specifically, many of the Staff's and DPA's proposals fail to recognize the Commission's practice of accepting reasonably known and measurable changes necessary to make the test period representative of the rate-effective period. Both Staff and DPA have offered revenue requirements, which, if accepted, would effectively guarantee that the Company would not be given a reasonable opportunity to recover its cost of providing service and to earn its authorized rate of return.

Q9. Can you discuss the Commission's past practice related to adjustments of test period data?

A9. Yes. This Commission has consistently allowed reasonably known and measurable adjustments to the test period to provide a level of cost of service that would be representative of the rate-effective period. For example, in Docket No. 91-20, the Hearing Examiner in his report on page 31 addressed the merits of adjustments that were offered by the Company in order to ensure that the costs upon which rates are set reflect the costs during the rate-effective period. The Hearing Examiner ruled that:

> The Company argues, and I agree, that such [out of period] adjustments "assure that the data utilized to set rate levels is representative of the costs of utility operations during the rate effective period."

The Commission confirmed that such adjustments are appropriate in its order in that proceeding (Order No. 3389) on page 29:

> First, the Hearing Examiner acknowledged that this Commission has frequently allowed out-of-period adjustments under certain circumstances when the adjustments are known and measurable and when the changes are of such magnitude that the test period will no longer be representative of the utility's operations.

The Commission further noted that support for known and measurable adjustment can be found in the Commission's Minimum Filing Requirements (MFR), which allow "a utility may adjust known and measurable changes to future rate base items."

Q10. How do the Commission's MFR support known and measurable adjustments test period data?

A10. MFR Part A, Section 1.3 provides that:

> Modifications in test period data occasioned by reasonably known and measurable changes in current or future rate base items, expenses (i.e., labor costs, tax expenses, insurance, etc.) or revenues may be offered in evidence by the utility at any time prior to its filing of rebuttal evidence....

The Commission's MFR recognize the importance of adjusting actual data for known and measurable changes to assure that the data used to set rate levels is representative of the costs of utility operations during the rate effective period.

Contested Adjustments

Adjustment No. 2, Regulatory Commission Expense

Q11. Please describe the Company's adjustment for regulatory commission expense.

A11. In my Direct Testimony, I proposed an adjustment to normalize regulatory commission expenses using a three-year average. I also included the cost of this filing to be amortized over a three-year period with the unamortized amount included in rate base.

Q12. Do Staff and DPA agree with the Company's Regulatory Commission Expense adjustment?

A12. No, not completely. The parties agree on some issues and not on others. The parties agree on the amount used in the normalization of non-base case expense using a three-year period. The parties also agree with the use of a three-year period to recover the cost of this proceeding. The parties differ on the amounts to be recovered for this case. The parties also disagree with the inclusion of the unamortized balance of rate case expense in rate base. Schedule (JCZ-R)-1, Page 2 provides a comparison of the parties' position on this issue.

Q13. What is Staff Witness Peterson's position on this adjustment?

A13. Staff Witness Peterson accepts the normalization of regulatory commission expense using a three-year average. With respect to the costs of this proceeding, he proposes using an average level of past rate case expenses. He also opposes including the unamortized balance of regulatory commission expenses in rate base.

Q14. Please summarize DPA Witness Watkins' position.

A14. Witness Watkins also accepts the normalization of regulatory commission expense using a three-year average. With respect to the costs of this case, he also recommends a downward adjustment to the costs that the Company expects to incur. He recommends the costs of outside counsel in this proceeding be based on an average level of legal-related costs from past rate cases. He also recommends a 50% disallowance for the Company's cost of capital witness, arguing that Company Witness Hevert's fees are not comparable to that of the Staff's and DPA's cost of capital witnesses. He similarly proposes not including the unamortized balance of regulatory commission expenses in rate base.

Q15. You stated that both Staff Witness Peterson and DPA Witness Watkins oppose including the unamortized balance of regulatory commission expense in rate base. Do you agree with their positions?

A15. No, I do not. The costs incurred by the Company related to regulatory proceedings, like this case, are required and necessary costs that the Company has and will actually incur prior to the Commission issuing an order in this proceeding. As a regulated Company, Delmarva is required to engage in a rate case if it seeks any adjustments to its rates, including the recovery of costs associated with investments that have and will be made by the Company in order to ensure that it may continue to provide safe and reliable service to its customers. The costs incurred with such proceedings are a required cost of doing business that must be included in the final revenue requirement in this proceeding.

Q16. Please comment on Staff Witness Peterson's use of an average level of past rate case expenses to set the rate case expense level for this proceeding.

A16. The appropriate level of rate case expenses for this proceeding as to which the Company should be allowed recovery is the level that the Company expects to incur to present its case. The average proposed by Staff Witness Peterson has no relationship to the expected level of costs as his average contains a mix of litigated and settled cases.

Q17. Please comment on DPA Witness Watkins's proposal to limit the costs associated with outside counsel to the average legal experienced in past cases as well as his disallowance of 50% of the Company's Cost of Capital witness fees

A17. DPA Witness Watkins' support for reducing outside counsel costs from the Company's proposal of $315,000 to his proposed $120,000 is his contention that the expense level should relate to the outside counsel involvement in the Company's previous three base rates cases. Given that the two previous cases were settled before a large portion of legal services are typically rendered for activities such as witness preparation, hearings and brief preparation, comparisons to those settled-case amounts cannot be assumed to be representative of this case since one cannot assume that this case will settle. In terms of the actual outside legal counsel expenses incurred in recent PHI utility litigated cases, the estimate used for this filing is reasonable.

In terms of the Cost of Capital witness fees, these are the actual costs related to the various activities required by the Company to properly support its cost of capital position. These activities include but are not limited to the preparation of testimony, the evaluation of other parties' testimony, the preparation of discovery responses, witness preparation, participation in hearings and support during the briefing process. It is the Company's position that the fees charged for these services are reasonable and thus should be included, in full, as part of the rate case expense in this filing. DPA has offered no reasonable basis for accepting the fees charged by the Staff and DPA cost of capital witnesses as a benchmark against which to compare Company Witness Hevert's fee associated with this proceeding.

Q18. Can you summarize your position on regulatory commission expense?

A18. Yes. The Company should not be precluded from recovering rate case costs that are necessary to establish rates in this proceeding. The Company is required to follow established procedures prior to re-establishing rates. The costs associated with that process are required and a necessary business expense and should be included in cost of service. The Company's supported costs associated with this proceeding are the amounts that the Company will pay to process its application. It is critical to note that the Company has the burden of proof and the costs included in the Company's request are what it expects to incur to meet its burden of proof.

<u>Adjustment No. 5, Wage and FICA Adjustment</u>

Q19. How is the Company's adjustment for the Wage and FICA increase computed?

A19. Using the method approved in Docket No. 91-20 as well as Dockets No. 05-304 and 09-414, I adjusted the test-period monthly wage levels by applying wage increases that are reasonably known and measurable. The calculation maintains the quantities that are included in the historic test period ending December 31, 2012, and adjusts for price changes only. I reflected the change in wages and resulting FICA tax for the period that the new rates will be in effect, the twelve months ending June 2014. As required by the Commission, I have reflected the effects of the wage and salary increases through the rate-effective period rather than putting the full annualized effect of all of the increases into cost of service. This adjustment is shown in Schedule (JCZ-R)-3.

Q20. Could you please summarize the Commission's past practice as it relates to the treatment of wage and FICA expenses for rate-setting purposes?

A20. Yes. The Commission has consistently recognized that reasonably known and measurable price changes, such as this wage and FICA adjustment, are to be included in the determination of the appropriate revenue requirement. Reflecting known and measurable price changes allows the Commission to ensure that rates are reflective of the Company's costs during the rate-effective period. It is consistent with Commission practice to adjust the test period to properly reflect, as closely as practical, the conditions that will exist during the first year the new rates are in effect.

Q21. Has the Commission issued any decisions that address this issue?

A21. Yes. The Commission provided guidance on this issue on page 82-83 in Order 3389 in Docket No. 91-20. The Commission stated:

> 154. The OPA did not object to Delmarva's adjustments for wage increases during the test period. Consistent with its strict adherence to the test period concept, however, the OPA recommended that the out of period December 1991 wage increase be disallowed. The OPA's adjustment increased Delmarva's test period earnings by approximately $409,000.
>
> 155. Discussion. The Hearing Examiner recommended that the OPA's proposal be rejected for the same reasons he expressed in rejecting the Tall Stack issue. As with the Tall Stack, the costs associated with the December 1991 wage increase were known and ascertainable, and were of such magnitude as to significantly affect Delmarva's ability to earn its authorized rate of return during the rate effective period. The OPA again pressed its arguments on exceptions. We agree with the Hearing Examiner, however, and adopt his recommendation on this issue.

The Commission ruled on this issue again on pages 51-54 in Order No. 6930 in Docket No. 05-304. The Commission stated:

> 112. **Discussion and Decision.** We are sympathetic to the DPA's argument regarding how far outside the test period these adjustments go. However, we recognize that several of the adjustments relate to contractually-required wage and salary increases that the Company is not free to ignore and which are known and measurable. We also recognize that the Company has reflected the effects of the wage and salary increases through the rate effective period rather than putting the full annualized effect of all of the increases into its

> expenses. Therefore, for these reasons and the reasons set forth by the Hearing Examiner, we adopt the Hearing Examiner's findings and recommendations.

It should be noted that in Docket No. 05-304, the Commission approved estimated non-union wage increases that were similar to the Company's position in this proceeding.

In Docket No. 09-414, the Commission on page 41 of Order No. 8011 once again allowed for post-test period wage and salary increases to be reflected in cost of service:

> 106. **Discussion.** We are sympathetic to the position that several of the increases take place far outside the selected test period. However, this seems to be one of those adjustments that the *Delmarva Power* decision would require us to consider in determining the cost of service. The wage increases at issue here are reasonably known and measurable, and their inclusion in the cost of service is more representative of the period during which rates set here will be in effect. The June 2009 wage increase took effect shortly after the close of the test period, and the March 1, 2010 increase took effect during the course of this case. And while we are not considering the fact that Delmarva reached new collective bargaining agreements with its unions since it is not part of the record, we do observe that in prior cases union contracts have included annual wage increases. *See Delmarva Power*, Docket No. 05-304. Thus, we reject the Hearing Examiner's recommendation, and approve Delmarva's request to include all of these wage increases in its cost of service. (Unanimous).

Q22. Please detail the specifics of the Company's adjustment for the Wage and FICA increase?

A22. The wage increases that I have included in this adjustment are either currently in effect, a result of union negotiations or are reasonably predicted based on history. Accordingly, these wage price increases are reasonably known and measurable and the Company's adjustment reflects the effect of these changes through the rate-effective period. The price increases reflected in the Company's adjustment are:

- the actual wage increase of 2.00% for International Brotherhood of Electrical Workers (IBEW) Local 1238 effective in February 2012 for 1 month,
- the actual non-union wage increase of 3.00% effective March 2012 for 2 months,
- the actual wage increase of 2.00% for IBEW Local 1307 effective in June 2012 for 6 months,
- the actual wage increase of 2.25% for IBEW Local 1238 effective in February 2013 for 12 months,
- the actual non-union wage increase of 3.00% effective March 2013 for 12 months,
- an estimated (contract negotiations currently ongoing in an effort to finalize a new contract) wage increase of 2.00% for IBEW Local 1307 effective in June 2013 for 12 months,
- the actual wage increase of 2.00% for IBEW Local 1238 effective in February 2014 for 9 months, and
- an estimated non-union wage increase of 3.00% effective March 2014 for 8 months.

Using the method approved in Docket No. 91-20, 05-304 and 09-414, I adjusted the test period monthly wage levels by applying these reasonably known and measurable wage increases. The calculation maintains the quantities that are included in the historic test period ending December 31, 2012, and adjusts for price changes only. The resulting wages and FICA tax are reflective for the period that the new rates will be in effect, the twelve months ending June 2014.

Q23. What is Staff's position on this adjustment?

A23. Staff Witness Peterson opposes the following proposed increases claiming that they are "speculative":

- 2% increase for Local 1307 in June 2013,
- 2% increase for Local 1238 in February 2014, and
- 3% increase for management employees in March 2014.

Q24. What is DPA's position on this adjustment?

A24. DPA Witness Watkins removes all of the Company's proposed Wage and FICA adjustments based on the fact that they occur beyond the end of the test period.

Q25. Please comment on Staff's and DPA's position.

A25. Staff Witness Peterson and DPA Witness Watkins fail to follow Commission precedent in Docket No. 05-304 on this issue. While these increases have not yet gone into effect, they are all reasonably known and measurable as they are reasonably predicted based on history.

The Hearing Examiner, in his decision at pages 104-105 in Docket No. 05-304, included wage increases that are either currently in effect, a result of union negotiations or are reasonably predicted based on history. The Hearing Examiner concluded that he agreed with the Company that its proposed adjustment, which included wage and salary increases that were predicted based on a comparison to historical wage and salary increases, is "reasonably known and measurable" and required by the Commission's minimum filing requirements. The Commission approved the Hearing Examiner's decision.

Q26. Are the wage increases that Staff Witness Peterson opposes here reasonably predicted based on history?

A26. Yes. The recent wage increases experienced by the Company over the last 8 years are as follows:

	LU 1238	LU 1307	Non-union
2013	2.25%	2.00%	3.00%
2012	2.00%	2.00%	3.01%
2011	2.00%	2.00%	3.01%
2010	0.00%	0.00%	3.09%
2009	3.00%	3.00%	0.00%
2008	3.00%	3.00%	3.60%
2007	3.25%	3.25%	3.49%
2006	3.25%	3.25%	3.31%
2005	3.50%	3.50%	3.34%

The two known LU 1238 and forecasted LU 1307 and non-union increases are consistent with the history of wage increases that I have identified above. Approval of the forecasts in this proceeding is consistent with the decisions of the Hearing Examiners in Docket No. 05-304 and Docket No. 09-414, as approved by the Commission.

Q27. Are Staff Witness Peterson's and DPA Witness Watkins' positions consistent with past Commission decisions?

A27. No. As I noted earlier, this Commission has consistently recognized that reasonably known and measurable price changes, such as this wage FICA adjustment, are to be included in the determination of the appropriate revenue requirement. It is appropriate to adjust the test period to properly reflect, as closely as is practical, the conditions that will exist during the first year the new rates are in effect. The wage increases that I have included in this adjustment are either currently in effect or will be in effect as a result of union contracts or are reasonably predicted based on history. These wage price increases are reasonably known and measurable and, following Commission precedent, the Company's adjustment reflects the effect of these changes only through the rate-effective period.

<u>Adjustment No. 8, Benefits Expense</u>

Q28. Please describe the adjustment made to reflect price changes related to the Company's employee medical, dental, and vision benefits expense.

A28. Consistent with the ratemaking treatment adopted in Docket No. 09-414, Order No. 8011, I have included an adjustment to account for cost increases necessary to administer employee benefits for the Company's active employee population. This adjustment reflects annual increases of 8%, 5%, and 5% for the Company's medical, dental, and vision test period expenses, respectively, to reflect the costs in the rate-effective period. This adjustment decreases test year operating income by $184,000 and is shown on Schedule (JCZ-S)-10 of my Supplemental Testimony.

Q29. What is DPA Witness Watkins' position on this adjustment?

A29. DPA Witness Watkins' adjustment is to remove the Company's proposed adjustment. DPA Witness Watkins asserts that the adjustment is "out-of-period." In addition, he rejects any reliance on the Lake Study healthcare survey letter.

Q30. What is Staff Witness Peterson's position on this adjustment?

A30. Staff Witness Peterson recommends rejection of the Company's proposed adjustment. Staff Witness Peterson suggests that the Company's adjustment to reflect price changes to the Company's benefits are not "known and measurable" and are not based on signed contracts.

Q31. Has the Commission addressed the issue of the known and measurable nature of these benefits costs in past proceedings?

A31. Yes. The Company in Docket No. 09-414, Order No. 8011, included a similar adjustment that was based on a study prepared by Lake Consulting. In that case, the Commission adhered to its practice of adjusting test period cost levels to reflect future out of period changes. In Docket No. 09-414, the Commission held:

> *The proposed increase for medical, dental and vision expense is reasonably known and measurable and more accurately reflects the costs that Delmarva will incur in the future to provide these benefits. We are bound by Delaware law requiring that rates be just and reasonable not only at the time we are setting them, but for some period thereafter (within reason, of course). Thus, we approve the adjustment to increase medical, dental and vision expense. (Unanimous).* (emphasis added)

Q32. You stated that the Company in Docket No. 09-414 relied upon a study prepared by Lake Consulting, Inc. to forecast its benefits cost increases. Did the Company rely on Lake Consulting once again here?

A32. Yes. In order for the Company to ascertain the level of cost increases to be expected during the rate-effective period, the Company once again relied upon its benefits expert, Lake Consulting, Inc., which performs a quarterly study surveying six major healthcare benefit providers in the Mid-Atlantic region, and asks for the trends that those providers are using to project cost claim changes for the upcoming year. As I stated above, the Lake Study served as the basis for forecasting the benefit increases that were approved by the Commission in Docket No. 09-414. These trends, which are forecast by actuarial experts working in the healthcare industry, afford a reasonably known and measurable estimate of how benefit costs will change over the course of the year. According to the Lake Study in the 2nd quarter of 2013, which is provided as Schedules (JCZ-R)-4.1, (JCZ-R)-4.2 and (JCZ-R)-4.3, the companies surveyed showed a mean trend of 8.8% for HMO, 9.5% for PPO, and 6.0% for Dental. The Lake Study also showed median percentages of 9.0% for HMO, 9.0% for PPO, and 5.5% for Dental. The Company has adjusted for the increased benefit costs that would be representative of the rate effective period.

Q33. Has the Company included in its adjustment the highest projected increase afforded by the Lake Study?

A33. No. The Company has chosen more conservative cost increases than either the median or mean cost trend afforded by the Lake Study. The Company's medical cost increase of 8% is below both the mean and median and its 5% cost increases for dental and vision are in the low range of trends reported in the Lake Study. These percentage increases are consistent with those used by the Company in forecasting its employee benefit increases for internal budgeting purposes.

Q34. Staff Witness Peterson states that these costs are "not based on signed contracts." Is he correct?

A34. Yes, but that fact is completely irrelevant given that the Company is self-insured. The fact that no signed contracts exist does not mean that the Company will not experience cost increases with respect to the Company's benefits nor does it mean that the costs are not known and measurable.

Q35. What is a Self-Insured Plan?

A35. A Company that is self-insured in the provision of healthcare benefits will, instead of purchasing insurance, act as its own insurer. In this type of plan, which PHI employs, the Company will directly pay health care claims to providers. Consequently, this type of plan can provide some measure of risk with respect to the Company's cash flow as the Company is fully liable for the level of claims and their associated costs. Naturally, it is extremely important for the Company to effectively forecast the extent to which the costs will change.

Q36. Please comment on Staff Witness Peterson's position on this adjustment?

A36. Staff Witness Peterson's concerns have no merit. The suggestion that the Company will not experience cost increases with respect to healthcare benefits because it is self-insured is unrealistic. Given the Company's use of a self-insured plan, the Company uses its business judgment as well as industry data provided by Lake Consulting, Inc., to estimate the increase in benefit costs over the rate-effective period. The Company's proposed increases are reasonably known and measurable, supported by industry data, and are more representative of the increased costs the Company will likely incur over the rate-effective period. In addition, the Company has chosen to incorporate increases below the surveyed average in its Company forecasts and revenue requirement. The Commission should reject Staff Witness

Peterson's "lack of signed" contracts argument as completely irrelevant and contrary to the ratemaking treatment approved by the Commission in Docket No. 09-414.

Q37. Are the Company's proposed adjustments in this case supported by the Company's actual history of medical, dental and vision expenses.

A37. Yes. The annual changes over the last five years in total Company benefit costs are as follows:

	Medical	Dental	Vision
2012	18.30%	8.15%	2.38%
2011*	-8.11%	-1.06%	-8.57%
2010	6.11%	7.73%	13.15%
2009	13.48%	0.11%	22.66%
2008	4.60%	8.55%	4.03%
5 Yr. Avg.	6.88%	4.69%	6.73%
4 Yr. Avg.*	10.62%	6.13%	10.56%

The declines in 2011 changes were driven by reduced headcounts resulting from the Organizational Review Process that reviewed and realigned resources after the 2010 divestiture of Conectiv Energy. In that regard, a 4-year average (excluding 2011 results is also shown). The benefit increases (8% - medical, 5% dental, 5% - vision) generally fall within the ranges set by the 5-year and 4-year adjusted averages.

Q38. Please summarize the Company's rebuttal position on increased expenses for medical, dental, and vision benefits.

A38. In Docket No. 09-414 Order No. 8011, the Commission approved the Company's adjustment, which was based on the Lake Study which also serves as the basis for the adjustment proposed in this case.

Given the self-insured nature of the Company's benefits plan, the Company has the risk of cost claim increases associated with the Company's medical, dental, and vision benefits. The Company's adjustment is below the average increases set forth in the Lake Survey, reflecting the Company's own business judgment. The Commission should accept the Company's adjustment, which reflects the increases costs of providing medical, vision, and dental benefits that would be representative of the rate effective period, as consistent with past Commission precedent.

Adjustment No. 9, Reliability Plant Closings (January 2013 – June 2013)

Q39. Please describe this adjustment in comparison to the one proposed in your Direct Testimony to address post-test period reliability plant closings.

A39. In terms of Adjustment No. 9 that was proposed in my Direct Testimony, I have taken the same time period's data and separated it into two adjustments. The first adjustment, (Adjustment No. 9 in my Rebuttal Testimony) details the reliability plant closings into the months which have been updated to actuals (January – June) and the other adjustment (Adjustment No. 9a) covers the period (July – December) which includes investments the majority of which will be placed into service prior to the time that the Commission issues a decision in this proceeding. The Company will provide actual reliability plant closings data updates during the course of this proceeding.

Q40. Please explain the Company's proposed ratemaking for reliability plant closings through June 2013.

A40. As approved by the Commission in Docket Nos. 05-304 and No. 09-414, this adjustment reflects the annualization of actual reliability plant added to plant during the test period through June 2013. This adjustment also reflects the removal of the associated test period level of CWIP and AFUDC and also reflects the annualization of any retirements to plant that occurred during this period. Schedules (JCZ-R)-5.2 and (JCZ-R)-5.3 provide support for the actual closings associated with this adjustment. I have attached Schedule (JCZ-R)-5, which provides the ratemaking associated with the annualization of the actual test period reliability plant closing adjustments.

Q41. What are the other parties' positions on this issue?

A41. Both Staff Witness Peterson and DPA Witness Watkins' rejected this adjustment arguing that they should be disallowed because the closings come after the test period.

Q42. Do you agree with Staff Witness Peterson and DPA Witness Watkins' comments?

A42. No. Staff Witness Peterson and DPA Witness Watkins' positions conflict with this Commission's practice of authorizing known and measurable adjustments to the test period so that the test period is representative of the rate-effective period. In his Direct Testimony, Company Witness Collacchi demonstrates that these projects are necessary to ensure safe and reliable service for all of the Gas Division customers. These additions to plant are known, measurable and are providing service to current customers, well before the beginning of the rate-effective period. To not allow these reliability projects to be included in rate base would cause a mismatch between the benefits received by customers as compared to appropriate and timely cost recovery of such investments by the Company.

Q43. Did the Commission render a decision on a similar Company adjustment in Docket No. 09-414?

A43. Yes. The Commission on Page 21 of Order No. 8011 held as follows:

> **Discussion.** We conclude that under the circumstances presented in this case, both the April-July 2009 and August-December 2009 reliability plant should be included in rate base. As previously discussed, we reject the DPA"s strict test period construction. We agree with the Company's position that the August 2009 – December 2009 reliability closings are no different from the April 2009 – July 2009 closings. We agree with Delmarva that these costs are known and measurable, and that they are necessary to make the test period more reflective of the period during which the rates approved in this case will be in effect. *See In re Delmarva Power & Light Company,* PSC Docket No. 91-20, 1992 Del. PSC LEXIS 15, Order No. 3389 (Del. PSC March 31, 1992) at 34. We are also persuaded that these plant additions are necessary to preserve the reliable operation of the distribution system and are not being made to serve future customers. While we note that the test period is there for a reason, we believe it is appropriate to include these costs in rate base based on the evidence presented. (Unanimous).

Q44. Are the reliability plant closings supported by the Company in this proceeding reasonably known and measureable?

A44. Yes, they are. As displayed on Schedule (JCZ-R)-5.3, the actual reliability plant closings are listed by project and by month.

Q45. Have the reliability plant closings supported by the Company actually occurred?

A45. Yes, they have. The reliability plant closings displayed on Schedule (JCZ-R)-5.3 have actually occurred.

Q46. Does the adjustment for reliability plant closings supported by the Company make the test period more representative of the rate effective period?

A46. Yes, these reliability plant closings are currently providing value to our customers. To exclude the effect of these reliability assets would not only cause a distortion in the benefits customers are receiving to the amount included in cost of service, but would not allow the Company the reasonable opportunity to earn its authorized return.

Q47. Did the Company provide details to the parties of the reliability plant closings?

A47. Yes. 12+0 Adjustment Workpaper #10.1 shows the 2013 forecasted reliability closings by month by project type. These projects are categorized as "Reliability" similar to those in Schedule (RMC)-2 in Company Witness Collacchi's Direct Testimony. In that schedule, projects are grouped into either "Reliability" or "New Business" categories. The Company defines Gas Reliability or Non-Revenue Projects as those projects that do not result in any new load or new revenue. These projects represent jobs that are directly related to maintaining service to existing customers and to maintaining gas pipeline safety. These projects are not for new customers or new load.

Gas reliability projects are driven by the need to provide safe reliable service to existing customers, provide no additional revenue, and the inclusion of these projects as included in the Company's adjustments is compelling.

Q48. While the concept of your post-test period reliability plant closings adjustment has not changed since your Direct and Supplemental Filings, have you modified the deferred income tax calculation for this adjustment to reflect a necessary revision given the Company's Net Operating Loss Carryforward (NOLC) position?

A48. Yes. I have corrected the deferred income tax calculations to reflect the Company's NOLC position. I discuss this issue in detail later in my Rebuttal Testimony.

Q49. Please summarize your position.

A49. Based on Commission precedent and the used and useful nature of these reliability plant closings that would be representative of the assets in service during the rate effective period, this adjustment should continue to be accepted. In addition, the deferred income taxes for this adjustment should properly reflect the Company's NOLC position.

<u>Adjustment No. 9a, Reliability Plant Closings (July 2013 – December 2013)</u>

Q50. Please describe this adjustment.

A50. As previously noted in the details related to Adjustment No. 9, this adjustment covers the post-test period reliability plant closings forecasted to occur in the period from July 2013 through December 2013. This ratemaking adjustment is shown in Schedule (JCZ-R)-5.1. Schedules (JCZ-R)-5.2 and (JCZ-R)-5.4 provide support for the forecasted closings associated with this adjustment.. As previously noted, the Company will provide actual reliability plant closings data updates during the course of this proceeding.

Q51. Do Staff Witness Peterson and DPA Witness Watkins support this adjustment?

A51. No. Their opposition of this adjustment stems from the fact that these reliability plant closings are forecasted to occur after the end of the test period.

Q52. Do you support the inclusion of these post-test period plant closings?

A52. Yes. These projects are reasonably known and measurable and are representative of the Company's costs during the rate effective period. As Company Witness Collacchi discusses, these projects enhance system reliability and do not generate incremental revenue. The projects are no different in character as those that are included in the adjustment for plant closings occurring during the period January 2013 through June 2013. Approval of these investments is consistent with the Commission's practice of ensuring that the test period is representative of the Company's costs during the rate-effective period. To not include these projects in cost of service creates a disconnect between the benefits that customers are realizing during the rate effective period from the reliability plant additions and the associated costs to provide those benefits.

Adjustment No. 11, AMI Net Plant Additions

Q53. Please describe your adjustment related to net AMI plant additions.

A53. For the AMI-related plant in service such as IMUs, communication equipment, hardware and software, a ratemaking adjustment is proposed to account for the difference in rate base and earnings related to full deployment near the start of the rate effective period compared to those same items at the end of the test period. This ratemaking adjustment is shown in Schedule (JCZ-R)-7. A large amount of the AMI plant is already deployed with a significant portion of that plant being used and useful while serving customers. The majority of the remaining plant is expected to be deployed and active later this year as discussed by Company Witness Collacchi. These balances will continue to be updated while the record in this proceeding is open.

Q54. Please discuss the recommendations of Staff Witness Peterson.

A54. Staff Witness Peterson rejects the Company's adjustment based on the premise that the 2013 AMI plant closings have or will occur after the end of the test period.

Q55. Please discuss the recommendation of DPA Witness Watkins.

A55. DPA Witness Watkins also rejects the Company's adjustment based on the same premise that Staff Witness Peterson does in terms of the closings occurring after the end of the test period. In addition, DPA Witness Watkins believes that there should be no recovery of any new AMI costs in this case. He proposes that the depreciation of currently used and useful AMI plant be deferred and recovered in future rates. He believes that the current AMI regulatory asset balances should no longer accrue a return despite the Company's investments in the various components that comprise them.

Q56. Would these AMI net plant additions have a similar NOLC-related deferred income tax position as the previously-mentioned post-test period reliability plant closings?

A56. Yes. The Company has revised the deferred income tax portion of this adjustment to reflect the Company's NOLC position described later in my testimony.

Q57. Please discuss the Company's position in regard to the recommendations of the other parties.

A57. The outside the test period position taken by the other parties goes against Commission precedent set in Docket No. 09-414 and previous cases, as discussed above with respect to reliability plant closings. The AMI plant is and will be used and useful during the rate-effective period. The Commission should reject the proposal of the other parties.

Adjustment No. 12, Meter Reading Expense

Q58. Please explain the normalization of meter reading expense.

A58. This adjustment removes a non-recurring test period reduction to meter reading expense related to a settlement with Silver Spring Networks (SSN), the manufacturer of the IMUs. The higher expense level in 2012 was incurred by the Company and not paid by customers. In addition, the Company proposed that meter reading expense savings created by the IMU deployment would be credited to the Gas AMI aggregate regulatory asset until the post IMU-deployment steady state level of meter reading expense was reflected in customers' rates.

Q59. What were the other parties' recommendations regarding the Company's proposed ratemaking for meter reading expense?

A59. Staff Witnesses Peterson and Cohen did not contest the proposed ratemaking. DPA Witness Watkins' rejected the Company's proposal.

Q60. Are you proposing different ratemaking than you did in your Direct Testimony?

A60. Yes. I removed the non-recurring SSN credit as proposed by DPA Witness Watkins to go along with the Company-proposed ratemaking of crediting meter reading expense savings beyond that amount to the Gas aggregate AMI regulatory asset until the post IMU-deployment level of meter reading expense is established as a recurring run rate in cost of service and gets factored into rates in a future base rate case. This ratemaking adjustment is shown in Schedule (JCZ-R)-8.

Q61. You discuss that AMI-related meter reading expense savings would be credited to a regulatory asset. What savings have been recorded to date?

A61. The Company began to realize meter reading expense savings in March 2013 and started recorded savings in the regulatory asset at that time. Through June 2013, the total savings are $69,074.

The Company forecasts that there would be increased levels of savings to be realized through the rate effective period and the use of the regulatory asset credits will ensure actual savings are passed on to customers as they are realized.

Q62. How do customers realize these benefits both now as well as in the future?

A62. By crediting these savings against a regulatory asset, they reduce the overall Gas aggregate AMI-related regulatory asset balance, resulting in lower customer base rates. These savings will continue to reduce this regulatory asset balance until the full extent of savings are realized and subsequently integrated into base rates in a future base rate case when the meter reading expense in cost of service would reflect the post-AMI run rate on a recurring basis. Once new base rates are set in this base rate case, the regulatory asset credits would be the difference between the meter reading expense level in the current test period cost of service and the actual amount of meter reading expense.

<u>Adjustment No. 19, Cash Working Capital</u>

Q63. Please describe your Cash Working Capital adjustment.

A63. This adjustment reflects the inclusion of the calculated cash working capital effect of all earnings ratemaking adjustments using the ratios supported in my testimony. Without this adjustment, the Company's cash working capital in rate base would only reflect the amount related to the per books balances.

Q64. Did Staff Witness Peterson recommend a similar adjustment to the Company's cash working capital adjustment?

A64. No, he did not.

Q65. Please describe DPA Witness Watkins' adjustment to your cash working capital study.

A65. DPA Witness Watkins is recommending the exclusion of cash working capital associated with purchased gas costs. He asserts that a significant amount of the Company's purchased gas is purchased and stored in the spring and summer months and withdrawn from storage and sold during the cold winter months. He also claims that "due to the nature in which the GCR operates, there may be no cash working capital requirement generated by these costs." He also states that "DPL is permitted to charge interest to ratepayers on under-recoveries in its GCR account. The fact that the Company already collects a carrying cost on this balance is another reason why DPL's cash working capital claim should be adjusted to eliminate gas costs."

Q66. Do you agree that this adjustment is appropriate?

A66. No, I do not. DPA Witness Watkins believes the Company incorrectly assumes a matching of monthly revenues and expenses. In his testimony he states that in any particular month the revenue received by the Company may be paying for purchased gas in the past or for gas to be used in the future.

In fact, however the majority of the monthly gas purchases are to serve the customers in a given month. The customer is billed monthly based on usage. The difference between when the Company pays for gas purchased and when the Company receives payment from customers clearly generates a cash working capital requirement. The fact that there are carrying costs associated with over or under recoveries does not differentiate a cash working capital requirement for purchased gas costs. The interest calculated on over or under recoveries is the FERC Gas Refund Rate of 3.25%, effective in the first quarter of 2013, which is low compared to the Company's overall rate of return presented in this proceeding of 7.53%. In addition, these amounts are rolled into the deferred fuel balance every year and are part of the GCR calculation. To exclude purchased gas costs from the lead/lag study denies the Company the appropriate level of cash working capital to be included in rate base.

Adjustments Proposed by the Other Parties

Year-End versus Average Rate Base (Year-End Customers and Adjustment No. 17 - Annualization of Depreciation Expense)

Q67. Please describe your proposed ratemaking for per books rate base?

A67. I propose that the per books rate base used in the development of the Company's revenue requirement be the test period year-end balances as of December 31, 2012.

Q68. What other adjustments were made in conjunction to the inclusion of year-end rate base?

A68. Company Witness Santacecilia adjusted revenues to include an annualization related to year-end customer counts. In addition, an adjustment to annualize depreciation expense related to year-end plant balances was made. These adjustments ensure that revenues and depreciation expense properly match the year-end balances, which would be more representative of the rate effective period. These proposed adjustments ensure that revenues and depreciation expense properly match the year-end rate base.

Q69. What are the other parties' positions in regard to the inclusion of year-end rate base and the other related adjustments?

A69. Both Staff Witness Peterson and DPA Witness Watkins proposed adjustments to use average rate base; however, DPA Witness Watkins' adjustment only pertains to AMI-related plant

Q70. What is the precedent in Delaware in terms of approved rate base?

A70. In the past, the Commission has approved the use of average rate base.

Q71. Why should the Commission consider a change in precedent in this regard?

A71. The Company's net plant in service continues to grow as shown in Schedule (JCZ-R)-11 while reliability investments to replace aging infrastructure are being made. Overall rate base has grown at a lower rate due in part to lower fuel inventory balances in recent years. At the same time, distribution revenue growth has not grown at similar rates as shown in Schedule (JCZ-R)-11. The combination of increasing rate base and lower revenue growth results in regulatory lag that has contributed to Company under-earning over the recent years. These results are shown below using data from the Company's annual rate of return reports in regard to its return on equity (ROE):

Year	Earned ROE	Adjusted ROE	Rev. Deficiency ($ Millions)
2012	6.88%	10.00%	$7.0
2011	9.18%	10.00%	$1.5

2010	6.92%	10.00%	\$5.6
2009	8.77%	10.25%	\$2.7
2008	9.38%	10.25%	\$1.6

Q72. Is year-end rate base used in other jurisdictions?

A72. Yes. There is a mix throughout the United States in terms of Commissions that use average rate base as well as ones that use year-end rate base. In PHI utilities' other jurisdictions, the New Jersey Board of Public Utilities has approved the use of end-of-period (or terminal) rate base while the District of Columbia and Maryland Commissions generally use average rate base.

In terms of Commission precedent throughout the United States in past and pending natural gas base rate cases filed in 2012 based on data from Regulatory Research Associates, 2 past cases and 4 pending cases use year-end rate base as the valuation method while 4 past cases and 18 pending cases use average rate base as the valuation method. In terms of past and pending electric base rate cases filed in 2012, 3 past cases and 18 pending cases use year-end rate base as the valuation method while 10 past cases and 24 pending cases use average rate base as the valuation method.

While the use of average rate base is more common, it should be noted there are Commissions that support the use of year-end rate base for its rate base valuation method.

Q73. Please summarize the Company's position in regard to its proposal to use year-end rate base and its related other adjustments.

A73. The dynamics of the gas business are changing. Rate base continues to grow to ensure safe and reliable service to customers yet revenue growth has not kept pace. Given this scenario, the Company believes that the use of year-end rate base better reflects the increasing net investment in rate base that would be representative of the rate effective period. As such, the Company respectfully requests that the Commission consider the use of year-end rate base its related other adjustments.

CWIP and AFUDC

Q74. Did you include Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) in the Company's per books rate base?

A74. Yes, I did.

Q75. Did Staff Witness Peterson and DPA Witness Watkins contest this ratemaking?

A75. Yes. They both made adjustments to exclude these items citing prior Commission precedent.

Q76. Please explain why CWIP and accrued AFUDC should be included in cost of service?

A76. Distribution projects are made up of thousands of work requests/work orders that, on an annual basis, account for the on-going additions to rate base in the form of new assets which comprise incremental capital units of property. These assets are characterized as having short construction durations and, on a per unit basis, a low cost when compared to major plant additions such as new gate stations. As stated earlier, the Company follows the appropriate procedure for accruing AFUDC at the work request/work order level. Many of these distribution projects collect no AFUDC and the majority of them that do, accrue it for only a few months.

The risk that these new distribution projects will not result in new units of property approaches zero. These new assets are closing to plant on a daily basis. The majority of this work is related to reliability, existing load and new customer service connections. A portion of these costs represent General plant, which, for the most part, is also characterized as lower cost, short schedule units of capital property. It is appropriate to afford rate base treatment to these projects which are now either in service and serving customers or will be in service and serving customers before a decision is rendered in this case.

Q77. Do you propose an alternative in this proceeding if CWIP and AFUDC are not included in cost of service?

A77. Yes, I do. If the Commission were to decide not to include CWIP and the associated accrued AFUDC in cost of service, I believe that there is a reasonable alternative that should be acceptable to all of the parties. The Company could record AFUDC on all CWIP. The difference between the actual accrued, recorded AFUDC and the full calculated AFUDC would be recorded as a regulatory asset. This regulatory asset would be treated in the Company's next case just as if had been actually accrued AFUDC; it would be amortized over the depreciable life and included in rate base just as if had been capitalized.

Q78. When do you propose that the calculation of this "Full AFUDC" would begin?

A78. It would seem appropriate that it would begin when final rates in this proceeding become effective. In the Company's next proceeding, the balance of this regulatory asset would be determined from the point in time that rates were established in this proceeding through the end of the test period in the Company's next proceeding. That balance would be amortized using the average book life with the regulatory asset included in rate base. The next regulatory asset would then begin at that time, starting at end of the next case's test period.

Incentive Expense

Q79. Please explain your proposed treatment of Incentive Compensation Expense.

A79. As discussed in the rebuttal testimony of Company Witness McGowan, although the Company believes that performance based incentives for Company executives are an established compensation method that benefits both customers and the Company, Delmarva decided not to seek recovery of such expenses in this case. Accordingly, I proposed removing executive incentive expense of $843,110 from cost of service.

The Company did, however, include the test period level of non-executive incentive compensation in the Company's cost of service. Such incentives are a critical element of the overall compensation package that is essential to attract and retain talent to provide safe and reliable service to our customers.

Q80. Did the Commission approve the recovery of non-executive incentives in past Delmarva cases?

A80. In Docket No. 09-414, the Company's last electric base rate proceeding, the Commission did not include the expense associated with non-executive incentives in cost of service because there it found that the Company did not separately provide a breakout of evidence establishing the level of the costs associated with the components related to safety, reliability and similar goals. The Commission, in its deliberation, discussed being its treatment of this expense item in a prior proceeding, Docket No. 05-304. In Docket No. 05-304, the Commission had included incentive costs associated with achieving safety, reliability and similar goals as part of its approved revenue requirements.

Q81. Can you provide detail of the test period non-executive Incentive expense?

A81. Yes. As provided in the response to Data Request No. PSC-RR-29, the total non-executive incentive compensation expense in the test period is $894,431. Of this total, $323,229 is related to customer satisfaction and reliability, $102,956 is related to safety, $40,404 is related to Affirmative Action and $64,210 is related Employee Recognition and other awards. The remainder, $363,632, is associated with financial-related items.

Q82. What are the other parties' positions on your proposed treatment of non-executive incentives?

A82. Both Staff and DPA propose removing some level of the non-executive incentive expense, which is mainly comprised of Annual Incentive Plan (AIP), from the cost of service. Staff Witness Peterson removes $808,072, 100% of AIP-related non-executive incentive expense, claiming that such disallowance is consistent with the Commission's treatment in Docket No. 09-414. As I explain below, Staff Witness Peterson inaccurately interprets the Commission's prior orders on that issue. DPA Witness Watkins proposes removing a significant amount ($391,450) that he states should not be included because it is not related to the achievement of safety and customer service goals.

Q83. Why is Staff Witness Peterson's representation of the Commission's prior treatment on this issue inaccurate?

A83. Staff Witness Peterson's representation of prior Commission treatment is inaccurate for several reasons. First, prior to Docket No. 05-304, the Commission allowed inclusion of all non-executive incentive expense in cost of service. Second, in Docket No. 05-304, the Commission allowed inclusion of non-executive incentive expense in cost of service related to safety, reliability and customer service goals. Finally, in Docket No. 09-414, the Commission disallowed non-executive incentive compensation not because it determined that recovery of those costs would be inappropriate, but because it determined that Delmarva did not specifically itemize the portion of the overall non-executive incentive expense that was attributable to the achievement of safety, reliability or customer service goals. The Commission did not, as Staff Witness Peterson appears to suggest, disallow the expense on the basis that none of the non-executive incentive costs may be recovered.

Q84. What is the Company's position on non-executive incentive expense?

A84. The Commission's decision in Docket No. 05-304 limited the recovery of non-executive incentive expense to those costs related to safety, reliability or customer service goals. However, the Commission, prior to Docket No. 05-304, recognized the full amount of these costs in rates. While Delmarva Power acknowledges the Commission's ruling on this issue in Docket No. 05-304, it respectfully requests that it should be permitted to recover the full amount of its non-executive incentive/AIP compensation expense, including the amount ($530,799) associated with financial-related items. In his Rebuttal Testimony, Company Witness

McGowan provides further details related to the importance of incentive compensation in regard to the overall compensation of employees that both allows the Company to attract and retain skilled employees and creates incentives to attain levels of performance that benefit customers.

Payroll Expense Factor

Q85. Did Staff Witness Peterson propose an adjustment to reduce the Company's payroll expense factor?

A85. Yes. Staff Witness Peterson proposes an adjustment to reduce the payroll expense ratio by 2.74%, or $228,267, with a like amount subsequently reclassified as capital. Staff Witness Peterson proposes this adjustment based on a five-year average because the payroll expense ratio in 2012 is higher than the five-year average.

Q86. Did Staff Witness Peterson make any adjustments to the per books payroll expense data?

A86. No. Staff Witness Peterson used the per books data provided in the response to PSC-RR-28 for the annual payroll amounts that were expensed and capitalized for the five-year payroll expense average upon his he based his adjustment.

Q87. Were there any 2012 events that would have made it less comparable to the other years that Staff Witness Peterson used for comparative purposes?

A87. Yes. The accounting method used to record gas meter reading expense changed in 2012 as a result of AMI deployment timing. In years prior to electric AMI deployment in Delaware, the Company's meter readers would read both electric and gas meters. In terms of how these meter reading costs were accounted on the Company's books, all costs were first directly charged to electric meter reading, given that the majority of meter reading was done on the electric side, and then an allocation was made to the Gas Division based on the respective Gas number of meters read compared to the total Electric and Gas meters read. Given that these gas meter reading expenses were an allocation of costs, they were not directly charged to the salaries general ledger account that Staff Witness Peterson used as a basis for his adjustment. These Gas meter reading expenses were in a Transfer Charges general ledger account in years prior to 2012 so an adjustment is required to ensure comparability of the years used by Staff Witness Peterson.

Q88. How does the 2012 payroll expense compare to the prior years when the change in gas meter reading salary expense is taken into consideration?

A88. Schedule (JCZ-R)-12 shows that after 2012 payroll expense has been adjusted for the change in accounting method, the 2012 payroll expense ratio of 68.19% is comparable to the five-year average of 66.60%. In addition, another increase from 2011 to 2012 was driven by increased Call Center resources.

Q89. Do you support the use of the test period payroll expense ratio for the rate effective period?

A89. Yes. I agree that the payroll expense ratio is higher than prior years on an unadjusted basis. 2012's higher payroll expense ratio has been primarily influenced by change in accounting method attributable to gas meter reading expense.

Q90. Should the Commission approve Staff Witness Peterson's proposed reduction to the test year payroll expense ratio?

A90. No. With the adjustment to Staff's Witness Peterson's calculation for the inclusion of the effect of the change in gas meter reading expense accounting, the

2012 payroll expense ratio is likely to be more representative of the rate effective period and is comparable to the average over the past 5 years. There is no reason to use a historical bias to the test period payroll expense ratio when an accounting change has occurred, such as the change in which gas meter reading expense is recorded on the Company's books, and will continue to occur although the amount will decrease based on the previously discussed IMU deployment and activation.

AMI Regulatory Asset Recovery

Q91. Can you provide an update in regard to the Gas AMI-related regulatory assets?

A91. Yes. As of June 2013, the Gas-related AMI regulatory asset balances were:

- The net book value of remote indexes that have been retired early due to AMI deployment of Interface Management Units (IMUs). The balance is $2.579 million.
- Deferred O&M costs incurred from August 2010 (the deferred costs incurred prior to that date were approved for recovery in Docket No. 10-237). The balance is $2.661 million.
- AMI Returns representing recovery of and on the appropriate costs associated with the AMI regulatory assets as well as AMI-related incremental net rate base that is providing service to customers. These returns have been calculated at the Company's authorized rate of return. The balance is $212,000.
- Incremental IMU depreciation expense compared to the expense related to the remote indexes. The balance is $232,000.
- Operational & Maintenance expense savings as detailed in the business case in Docket No. 07-28. The balance is a credit of $69,000.

In summary, the net balance of all of the above-mentioned regulatory assets is $5.616 million as of June 2013. As stated in my Direct Testimony, Delmarva will not be able to collect these costs until the remote meter reading benefit, the primary AMI benefit upon which the Commission based its Gas AMI approval in Order No. 7420, is achieved.

Q92. Please describe the Company's recovery plan for these AMI Regulatory Assets.

A92. The Company proposed that the recovery plan for its aggregate Gas AMI Regulatory assets would be milestone-driven similar to the approved plan for recovery of its Electric AMI Regulatory assets in Docket No. 11-528. The primary AMI-related milestone for Gas customers would be meter reading expense savings enabled by the IMUs. Subsequently, the Company proposed this single milestone as the criteria (reading at least 95% of eligible natural gas meters remotely through the IMUs) to be met prior to the Company making a filing to begin recovery of the regulatory asset costs over a 15-year amortization period with the unamortized balance included in rate base. Similar to the plan approved in Docket No. 11-528, the other parties would have a 60 day period for discovery in regard to the regulatory asset balances and the achievement of the remote meter reading savings benefit to customers.

Q93. Please describe Staff Witness Cohen's recovery plan for the AMI Regulatory Asset.

A93. Staff Witness Cohen proposes a recovery plan that is similar in concept to the one proposed by the Company; however, he proposes that the recovery should be broken into two phases and adds an additional milestone in regard to accurate and timely meter readings over a six month period. His proposal is detailed as follows:

- Phase 1: 50% of the regulatory asset balances would be eligible for recovery using an April 1, 2014 filing with a 60 day discovery period similar to the plan in Docket No. 11-528. The new rates related to this recovery would become effective June 1, 2014. The milestones that would need to be achieved for this phase would include (1) 95% of the IMUs would be installed and active at customers' premises and (2) those active IMUs would be providing 99.8% accurate and timely readings for six months. Given the forecasted full deployment date of September 2013, this timing would allow for the assessment of the IMUs performance to include the winter months when a larger portion of gas flows through the meters.
- Phase 2: the remaining regulatory asset balances would be eligible for recovery using an April 1, 2015 filing with a 60 day discovery period similar to the plan in Docket No. 11-528. The new rates related to this recovery would become effective June 1, 2015. The milestones that would need to be achieved for this phase would include (1) 99% of the IMUs would be installed and active at customers' premises and (2) those active IMUs would be providing 99.9% accurate and timely readings for six months.

Q94. Please comment on Staff Witness Cohen's proposal and the Company's response to it.

A94. The Company generally is agreeable to certain aspects of Staff Witness Cohen's plan. These include:

- Establishing two phases for the recovery plan,
- Having the remaining aggregate regulatory asset balances be eligible for recovery in the 2nd phase

The Company would propose the following modifications to Staff Witness Cohen's plan:

- Upon the Company deploying and activating at least 95% of the IMUs at customers' premises, the Company would make a filing six months later for recovery of the initial phase-in amount related to its aggregate AMI regulatory balances.
- While the Company understands the need to assess the IMU performance during the winter months, the Company proposes that the amount of the recovery should be 75% of the aggregate AMI regulatory balances, not the 50% proposed by Staff Witness Cohen, given that 100% of the IMU investment to achieve full deployment is planned to have been incurred before the October 2014 date that Staff Witness Cohen targets as the start date for the six month IMU performance assessment period.

The Company does not agree with the performance targets offered by Staff Witness Cohen as a necessary pre-condition to recovery. The timely and accurate meter reading requirement needs to factually supported and clearly defined given the change in technology. Choosing a 99.9% accuracy requirement without evidence establishing that the new technology is designed and expected to perform at that level of accuracy is arbitrary. Also, it fails to account for events that are beyond the Company's control such as storm damages which may affect the AMI infrastructure.

Staff Witness Cohen has not offered any support for his proposed criteria in this area in a post-AMI period. In additions, the definitions of timely and accurate meter reading require clarification. For example, the meter reading error criteria should not reflect meter reading issues that are (1) remedied prior to a customer receiving a bill or (2) still pending that prompt the need for an estimated bill until the meter reading issue is remedied. Staff Witness Cohen's proposal does not address these issues. The proposal does not address remedies if the criteria are not met. For example, the second phase-in should be triggered should have remedies in the event that the activation milestone is not met, or met after the prescribed date, due to unforeseen circumstances beyond the Company's control. The Company should be able to make its regulatory asset cost recovery filing six months after the milestone is met.

Based on the above-mentioned items, Staff Witness Cohen's proposed meter reading metric should be rejected; however, the Company would be willing to further discuss this issue in terms of establishing a mutually agreed-upon performance metric milestone.

Q95. Please describe the DPA Witness Watkins' proposal for the AMI Regulatory Asset.

A95. DPA Witness Watkins asserts that any AMI-related costs, such as plant in service or regulatory assets, not currently in base rates should not be included in base rates that will become effective as part of this filing. Despite these assets being used and useful and thus representative of the rate effective period, he believes that none of these costs should earn a return "until such time as the AMI program is operational and fully functioning, and ratepayers are receiving the benefits of lower meter reading cost in their base rates."

Q96. Please comment on DPA Witness Watkins' proposal.

A96. DPA Witness Watkins' proposal goes against Commission precedent in terms of used and useful tests for rate base, the concept of a rate effective period and ratemaking related AMI regulatory assets. His proposal should be rejected.

<u>Other Revenue Requirement Items</u>

Q97. Please describe correcting adjustments that you are supporting that were learned during the discovery process.

A97. There are two items, which the Company learned during the discovery process, that it determined should be corrected. These include:

1) Adjustment No. 13, Amortization of Refinancings (shown on Schedule (JCZ-R)-9: this adjustment has been updated for the August 2012 redemption of $96.74 million tax-exempt pollution control refunding revenue bonds that was not included in the original adjustment and
2) Adjustment No. 19, Cash Working Capital: in the Company's response to PSC-RR-10, the Company acknowledged that $14,514 of prepaid insurance was included in rate base as well as reflected in CWC allowance. The Company has removed this amount from rate base.

<u>Net Operating Loss Carryforward (NOLC)</u>

Q98. In preparing your rebuttal testimony, did you discover any revisions that were required to your reliability, AMI and Bloom plant-related adjustments proposed in this proceeding?

A98. Yes. The adjustments that were included with my Direct and Supplemental testimonies failed to properly reflect the fact that the Company is now in a Net Operating Loss Carryforward (NOLC) position which requires an update to the deferred tax calculations associated with the adjustments. These adjustments are shown in Schedule (JCZ-R)-5 for January 2013 - June 2013 reliability plant closings, Schedule (JCZ-R)-5.1 for July 2013 – December 2013 reliability plant closings, Schedule (JCZ-R)-6 for Bloom and Schedule (JCZ-R)-7 for AMI. The NOLC position is mainly driven by bonus depreciation that allows businesses to more quickly recover their costs than traditional accelerated tax depreciation methods. The NOLC position reflects that while the Company was able to claim certain deductions associated with its capital expenditures on its tax returns, it was not able to use the deductions to offset any tax liabilities. In other words, tax deductions can only provide a benefit to the Company, and thus to customers, to the extent the deductions offset revenues and result in a reduced tax payment. The benefit to the Company is greater cash available for additional capital investments. In this case, the Company is not able to realize benefits through reduced tax payments because it is in a net operating loss position. Another way of saying this is that the very existence of the net operating loss position establishes that the Company has not had positive taxable income against which to apply the deductions. The revision that I have made to these plant-related adjustments reverse an inappropriate passing through of benefits in the form of a rate base reduction prior to the Company having realized any benefits associated with the deductions.

Q99. Could you please explain why a reduction to rate base to reflect the Company's NOLC position would be inappropriate?

A99. Yes. The best way to illustrate this point is to compare a situation where the Company has positive taxable income with a situation in which the Company is in a NOLC position. I have attached Schedule (JCZ-R)-13 that provides these two distinct situations. Scenario 1, viewed on Column 3 on the schedule, illustrates the situation when the Company has sufficient taxable income to use all of its tax deductions. In this scenario, the Company is making a cash tax payment of $200 while it is recording a total of $300 as tax expense on the Company's books. The Company reduces its tax otherwise payable by 40% of the difference between book depreciation included in cost of service ($250) and tax depreciation expense claimed on its income tax return ($500) – that is, by $250. This tax deferral provides a cash benefit to the Company through the reduced tax payment. Because the Company has received the cash benefit, customers receive the benefit of a reduction to rate base (and the resulting revenue requirement) in the amount of this deferral to reflect the fact that the capital has no associated cost.

Scenario 2, provided in Column 4 on Schedule (JCZ-R)-13, illustrates the circumstances that the Company is in now. When the Company has negative taxable income, it does not pay taxes. In such a situation, the Company can only record an offset to the deferred tax balance signifying that the Company because it cannot use the tax deduction at this time. If the Company cannot use the deduction, it derives no benefit from the deduction. As a result, it would be improper ratemaking to pass on to customers the benefit of a reduction to rate base.

Q100. Will customers ever receive the benefits associated with these deferred taxes?

A100. Yes. When the Company is able to use the tax deduction associated with positive taxable income, the offset will be reduced and the Company will include the deferred tax balance as a reduction to rate base. Until such time as the Company benefits from associated depreciation deductions through reduced tax payments, the Company must reflect a reduction to its deferred tax balance so that customers will not receive a benefit that the Company has not realized.

Q101. Please explain why the Company is in an NOLC position.

A101. Federal tax law permits the carryback of net operating losses to the two years immediately preceding the year of the loss and their carry-forward to the twenty years immediately following the year of the loss. Prior to 2011, the Company's tax net operating losses were generally realized on a carryback basis, and, as such, did not result in an NOLC. However, due to the magnitude of the tax losses in 2011 and 2012, which were predominately caused by bonus depreciation allowances and other property related tax deductions, the Company could not use the net operating losses in those years as carrybacks (due to insufficient taxable income in the carryback years) and was, therefore, required to carry the tax losses forward.

Q102. In addition to it being improper ratemaking to pass on benefits that the Company has not realized, are there any other reasons why a reduction to rate base is inappropriate?

A102. Yes. Being ordered by a Commission to exclude the NOLC deferred tax asset from rate base while including the benefits of accelerated depreciation (including bonus depreciation) that were not, in fact, realized yet may raise Internal Revenue Code normalization concerns.

Q103. How are the normalization rules implicated if the Commission were to order the Company to reduce rate base despite the fact that the Company has not yet realized any benefit associated with bonus (accelerated) depreciation deductions?

A103. The IRS normalization rules are contained in Internal Revenue Code (IRC) Section 168(i)(9) and Treasury Regulations Sections 1.167(l)-1(h)(1)(iii) and 1.167(l)-1(h)(6)(i). The IRC provides that rate base reductions are limited to the tax actually deferred on account of claiming accelerated (including bonus) depreciation. Because some portion of the deductions at issue here did not defer any tax liability, the Company did not receive the full cash benefit of its accelerated depreciation deductions. Absent such a case benefit, a Commission order requiring the passing through of benefits through a rate base reduction may raise a normalization issue.

Q104. What are the ramifications of violating the depreciation normalization rules?

A104. If the Company is ordered to reduce rate base in this case in violation of depreciation normalization, it will no longer be able to use accelerated methods of tax depreciation - including bonus depreciation. Instead, it will be required to use its regulatory method of depreciation for tax purposes, which provides significantly less benefit to both the Company and its customers. This would apply to all jurisdictional property owned when the violating order is issued, as well as all assets the Company acquires thereafter.

Q105. How would a violation affect the Company and its customers?

A105. By foregoing all future accelerated tax depreciation benefits, the Company would pay significantly higher taxes than it otherwise would, which would increase its capital requirements. This, in turn, would increase the cost to the customer. While the Company has not quantified the impact a normalization violation would have on the Company, given its substantial annual capital budget, over time, a violation may cause the forfeiture of large quantities of valuable cost-free financing that would have resulted from reduced tax payments to the government.

Q106. Please summarize your position.

A106. Based on the Company's NOLC position, the deferred income taxes for these post-test period plant-related adjustments should properly reflect that NOLC position in regard to the Company's ability to use those accelerated tax depreciation deductions.

Revenue Requirement Summary

Q107. Can you summarize the adjustments that are included in this filing?

A107. Yes. Schedule (JCZ-R)-1, Page 3 displays the filed positions of all of the parties in this proceeding. In addition, I have included the Company's rebuttal position of a proposed revenue requirement of $12.067 million.

Q108. Does this conclude your Rebuttal Testimony?

A108. Yes, it does.

Delmarva Power & Light Company
Docket No. 12-546
12 Months Ending December 31, 2012
(000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			Company Supplemental		Company Rebuttal		Staff Filing		OPC Filing	
Line No.	Item	Company Witness	Earnings	Rate Base	Earnings	Rate Base	Earnings	Rate Base	Earnings	Rate Base
1	Per Books - 12 m/e December 2012	Ziminsky	$14,779	$251,449	$14,779	$251,435	$14,779	$251,449	$14,779	$251,449
2										
3	Uncontested Adjustments by all Parties									
4	1 Remove Employee Association	Ziminsky	$19	$0	$19	$0	$19	$0	$19	$0
5	4 Removal of Executive Incentive Compensation	Ziminsky	$500	$0	$500	$0	$500	$0	$500	$0
6	5 Remove Certain Executive Compensation	Ziminsky	$9	$0	$9	$0	$9	$0	$9	$0
7	6 Uncollectible Expense Normalization	Ziminsky	($179)	$0	($179)	$0	($179)	$0	($179)	$0
8	7 Injuries and Damages Exp Normalization	Ziminsky	$10	$0	$10	$0	$10	$0	$10	$0
9	10 Remove Bloom-Related Incremental Rate Base	Ziminsky	$1	($306)	$1	($385)	$1	($306)	$1	($306)
10	13 Amortization of Refinancings	Ziminsky	($125)	$1,205	($128)	$1,258	($125)	$1,205	($125)	$1,205
11	14 Remove Post 1980 ITC Amortization	Ziminsky	($50)	$0	($50)	$0	($50)	$0	($50)	$0
12	16 Reflect Taxes Related to Medicare Part D Subsidy	Ziminsky	($7)	$14	($7)	$14	($7)	$14	($7)	$14
13										
14										
15	**Sub-total After Uncontested Adjustments**		$14,957	$252,362	$14,953	$252,322	$14,957	$252,362	$14,957	$252,362

Delmarva Power & Light Company
Docket No. 12-546
12 Months Ending December 31, 2012
(000's)

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				Company Supplemental		Company Rebuttal		Staff Filing		DPA Filing	
Line No.		Item	Company Witness	Earnings	Rate Base	Earnings	Rate Base	Earnings	Rate Base	Earnings	Rate Base
1	Uncontested Total from Page 1			$14,957	$252,362	$14,953	$252,322	$14,957	$252,362	$14,957	$252,362
2											
3	Contested Adjustments										
4	2	Regulatory Commission Exp Normalization	Ziminsky	($143)	$250	($143)	$250	($101)	$0	($95)	($0)
5	3	Wage and FICA Expense Adjustment	Ziminsky	($380)	$0	($396)	$0	($192)	$0	$0	$0
6	8	Benefits Expense Adjustment	Ziminsky	($184)	$0	($184)	$0	$0	$0	$0	$0
7	9	Reflect Actual Reliability Closings January 2013 - June 2013	Ziminsky/Collacchi	($248)	$16,736	($91)	$9,103	$0	$0	$0	$0
8	9A	Reflect Forecasted Reliability Closings July 2013 - December 2013	Ziminsky/Collacchi			($123)	$9,217	$0	$0	$0	$0
9	11	Reflect Gas AMI Net Plant Additions	Ziminsky/Collachi	($398)	$5,398	($398)	$6,075	$35	$0	$190	($6,617)
10	12	Normalize Meter Reading Expense	Ziminsky	($681)	$0	$0	$0	($681)	$0	$0	$0
11	15	Recover Credit Facilities Expense	Ziminsky	($70)	$182	($70)	$182	$0	$0	$0	$0
12	17	Annualization of Depreciation on Year-end Plant	Ziminsky	($227)	($227)	($227)	($227)	($227)	($227)	($160)	($227)
13	18	Interest Synchronization	Ziminsky	$363	$0	$385	$0	($91)	$0	($93)	$0
14	19	Cash Working Capital	Ziminsky	$0	($32)	$0	($92)	$0	$343	$0	($6,483)
15		Remove CWIP - AFUDC	Ziminsky					($294)	($12,953)	($277)	($9,095)
16		Use of Average (Not Year-end) Rate Base	Ziminsky					$227	($10,000)		
17		Capitalized Payroll	Ziminsky					$271	$229		
18		Remove Non-Executive Incentive Compensation	Ziminsky					$480	$0	$232	$0
19		Prepaid Insurance	Ziminsky							$0	($15)
20		Customer Advances	Ziminsky							$0	($1)
21		Revenue - Customer Growth	Santacecilia							$142	$0
22		Revenue - Year-End Customers	Ziminsky/Santacecilia					($77)	$0		
23											
24											
25		Total Contested Adjustments		($1,968)	$22,308	($1,247)	$24,508	($650)	($22,608)	($61)	($22,438)
26		Adjusted Test Period		$12,988	$274,670	$13,705	$276,830	$14,307	$229,755	$14,895	$229,924

Delmarva Power & Light Company
Docket No. 12-546
12 Months Ending December 31, 2012
(000's)

(1) Line No.	(2) Item	(3) Company's Supplemental	(4) Company's Rebuttal	(5) Staff's Filing	(6) DPA's Filing
1	Pro Forma Rate Base	$274,670	$276,830	$229,755	$229,924
2					
3	Rate of Return	7.53%	7.53%	7.15%	6.66%
4					
5	Required Return	$20,683	$20,845	$16,427	$15,313
6					
7	Pro Forma Operating Income	$12,988	$13,705	$14,307	$14,895
8					
9	Return Deficiency (Excess)	$7,694	$7,140	$2,121	$418
10					
11	Revenue Conversion Factor	1.69013	1.69013	1.69013	1.69013
12					
13	Required Rate Increase	$13,005	$12,067	$3,584	$706

Delmarva Power & Light Company
Revenue Conversion Factor
Delaware Gas Retail

Schedule (JCZ-R) - 2

(1) Line No.	(2) Particulars	(3) Factor	
1	**Tax Rates**		
2	Federal Income Tax	0.35000	
3	State Income Tax	0.08700	
4			
5	Regulatory Tax	0.00300	
6			
7	**Conversion Factor**		
8	Revenue Increase	**X**	
9			
10	Regulatory Tax	0.00300	**X**
11	Total Other Tax	0.00300	**X**
12			
13	State Taxable Income	0.99700	**X**
14	State Income Tax	0.08674	**X**
15			
16	Federal Taxable Income	0.91026	**X**
17	Federal Income Tax	0.31859	**X**
18			
19	Total Additional Taxes	0.40833	**X**
20			
21	Increase in Earnings (1 - additional taxes)	0.59167	**X**
22			
23	Revenue Conversion Factor (1/Incr in Earnings)	1.69013	**X**

Schedule (JCZ-R) - 3
Adjustment No. 3

Delmarva Power & Light Company
Wage, Salary, and FICA Expense Adjustment - Gas
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item		(3) Gas
1	**Salary and Wage Adjustment**		
2	Gas O&M Expense Adjustment		$633,423
3			
4	State Income Tax		($55,108)
5	Federal Income Tax		($202,410)
6		Total Expense	$375,905
7			
8	Earnings		($375,905)
9			
10			
11			
12	**FICA Adjustment**		
13	Gas O&M Expense Adjustment		$34,551
14			
15	State Income Tax		($3,006)
16	Federal Income Tax		($11,041)
17		Total Expense	$20,504
18			
19	Earnings		($20,504)
20			
21			
22	**Total Earnings Adjustment**		**($396,409)**

Lake Consulting, Inc.
7200 Bradley Boulevard
Bethesda, MD 20817
301-365-1964

May 23, 2013

Eileen M Kennedy
Accounting Program Manager
PEPCO Holdings, Inc.
PO Box 9239
Newark, DE 19714

Dear Eileen:

Here are the results of our medical trend survey for the second quarter of 2013. This represents the projected trends in use for the second quarter of 2013. Six companies in the region participated, and we thank all of them. We present the company by company results, the mean, the median, and the range of rates in each category of plan.

- For this quarter four of the seven categories showed a change from the mean average projected first quarter 2013 trends. HMO showed a decrease of 0.6%. POS, PPO and CDHP each showed a decrease of 0.1%.
- When compared to last quarter, two of the six companies made changes to their projected trends. One company decreased HMO, PPO, POS, Pharmacy and CDHP 0.5%. Another company decreased HMO 3.3% and PPO 0.3%, increased Pharmacy 0.4% and decreased CDHP 0.3%.
- The HMO second quarter 2013 mean average trend decreased 0.6% from first quarter 2013. One company decreased this trend 3.3%, and another company decreased it 0.5%. All other companies left this trend unchanged.
- The POS second quarter 2013 mean average trend showed a 0.1% decrease from this trend for first quarter 2013. One company decreased this trend 0.5%. All other companies left this trend unchanged.
- The PPO second quarter 2013 mean average trend showed a 0.1% decrease from this trend for first quarter 2013. One company decreased this trend 0.5% and another company decreased it 0.3%. All other companies left this trend unchanged.
- The Indemnity second quarter 2013 mean average trend shows no change from this trend for first quarter 2013. All five companies with Indemnity business left their trends unchanged.
- The Dental second quarter 2013 mean average trend showed no change from this trend for first quarter 2013. All companies left this trend unchanged.

- The Pharmacy second quarter 2013 mean average trend showed no change from this trend for first quarter 2013. One company decreased it 0.5% and another company increased it 0.4%. All other companies left this trend unchanged.
- The Consumer Driven Health Plan second quarter 2013 mean average trend showed a 0.1% decrease from this trend for first quarter 2013. One company decreased this trend 0.5% and another company decreased it 0.3%. All other companies left this trend unchanged.
- In the second quarter 2013 trend survey, no companies reported CDHP Pharmacy trend being different from the trend for CDHP base plans.

This quarter, the mean average projected CDHP trend is the lowest medical trend at 8.8% with trends ranging from 5.4% to 11.5%. HMO trend is also at 8.8% with trends ranging from 5.2% to 11.5%. POS has the next lowest trend at 9.2% with trends ranging from 7.1% to 11.5%. The PPO trend is the next lowest at 9.5% with trends ranging from 7.4% to 11.5%. Current Indemnity trends are still the highest of the medical trends at 11.1%, with a range of 9.0% to 16.5%. Dental trends are lower than medical, 6.0% mean average, with a range from 5.0% to 7.8%. Pharmacy trends, at 8.8% mean average, have a range from 5.0% to 11.5%.

We also want to show you these trends over time, so we have summarized by type of medical plan the trends since we began this survey. You will be able to see at a glance how your plan has compared with other plans. During the fifty-seven quarters we have collected data for all but CDHP (of which sixteen are displayed), we see the following changes:

- The mean average of HMO trends has increased from 5.3% to 8.8%.
- The mean average of POS trends has increased from 6.6% to 9.2%.
- The mean average of PPO trends has increased from 9.3% to 9.5%.
- The mean average of Indemnity trends is still at a low of 11.1%.
- The mean average of Pharmacy trends is at its low of 8.8%.
- The mean average of CDHP trends is lower at 8.8%.

We hope you will find these results both interesting and of value. We will send another survey soon, asking for third quarter 2013. Again, we thank you for your interest.

Sincerely,

Gary D. Lake, FSA

Jon R. Jennings

Gary D. Lake, FSA
Consulting Actuary

Jon R. Jennings
Consultant

Enclosures

Participating Companies

Aetna/USHealthCare

CareFirst of Maryland

CareFirst of Washington, DC

CIGNA HealthCare, Mid Atlantic

Kaiser Foundation of the Mid-Atlantic States

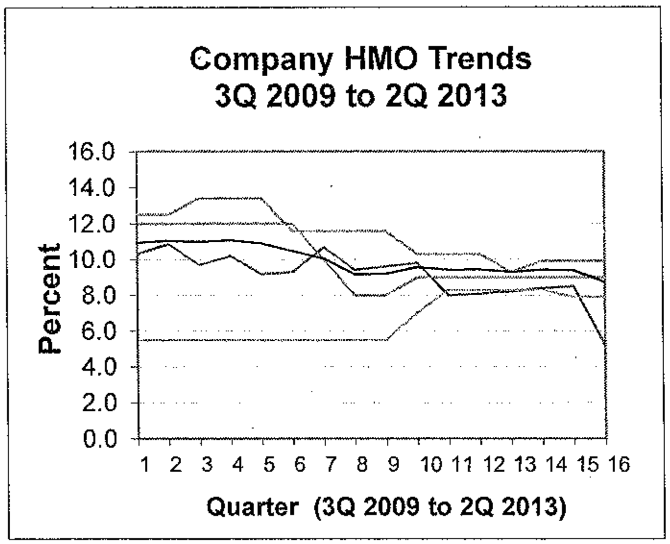
UnitedHealth Group

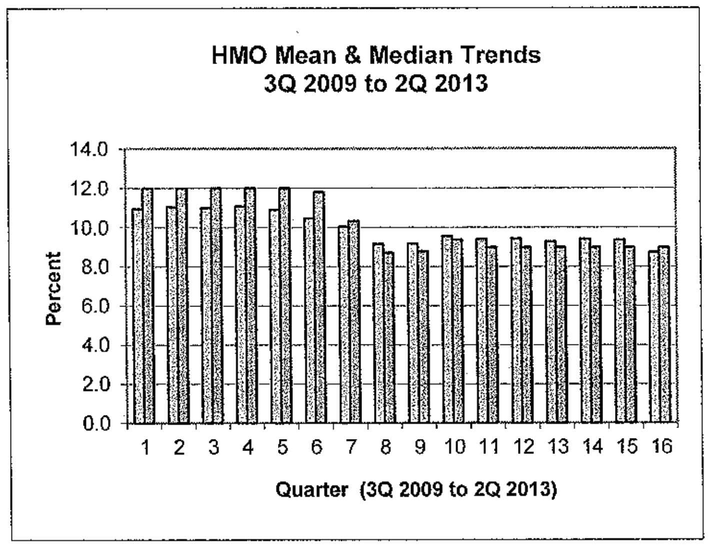
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

HMO Summary for 3Q 2009 to 2Q 2013

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2009	13.4	12.0	10.8	5.5	12.5	12.0	11.0	12.0	5.5	13.4
4 Q 2009	13.4	12.0	10.9	5.5	12.5	12.0	11.1	12.0	5.5	13.4
1 Q 2010	13.4	12.0	9.7	5.5	13.4	12.0	11.0	12.0	5.5	13.4
2 Q 2010	13.4	12.0	10.2	5.5	13.4	12.0	11.1	12.0	5.5	13.4
3 Q 2010	13.4	[illegible]	9.2	5.5	13.4	12.0	10.9	12.0	5.5	13.4
4 Q 2010	12.5	12.0	9.8	5.5	11.6	12.0	10.5	11.8	5.5	12.5
1 Q 2011	12.5	10.0	10.7	5.5	11.6	10.0	10.1	10.4	5.5	12.5
2 Q 2011	12.5	8.0	9.4	5.5	11.6	8.0	9.2	8.7	5.5	12.5
3 Q 2011	12.5	8.0	9.6	5.5	11.6	8.0	9.2	8.8	5.5	12.5
4 Q 2011	12.3	9.0	9.8	7.0	10.3	9.0	9.6	9.4	7.0	12.3
1 Q 2012	12.0	9.0	8.0	8.3	10.3	9.0	9.4	9.0	8.0	12.0
2 Q 2012	12.0	9.0	8.1	8.3	10.3	9.0	9.5	9.0	8.1	12.0
3 Q 2012	12.0	9.0	8.2	8.3	9.3	9.0	9.3	9.0	8.2	12.0
4 Q 2012	12.0	9.0	8.4	8.3	9.9	9.0	9.4	9.0	8.3	12.0
1 Q 2013	12.0	9.0	8.5	7.9	9.9	9.0	9.4	9.0	7.9	12.0
2 Q 2013	11.5	9.0	5.2	7.9	9.9	9.0	8.8	9.0	5.2	11.5



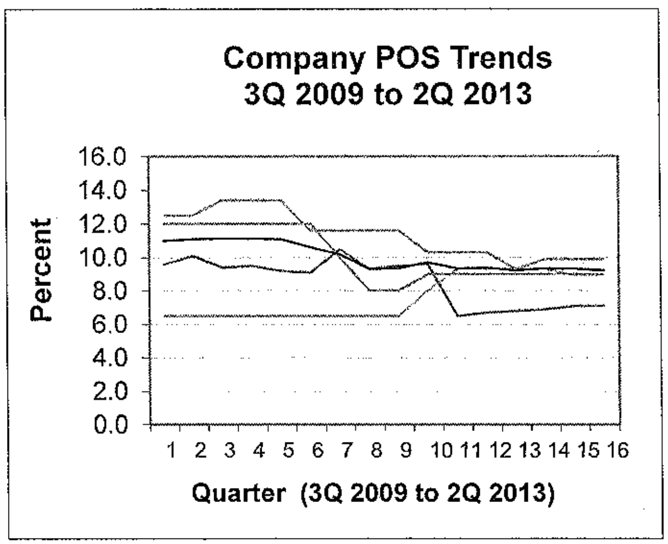


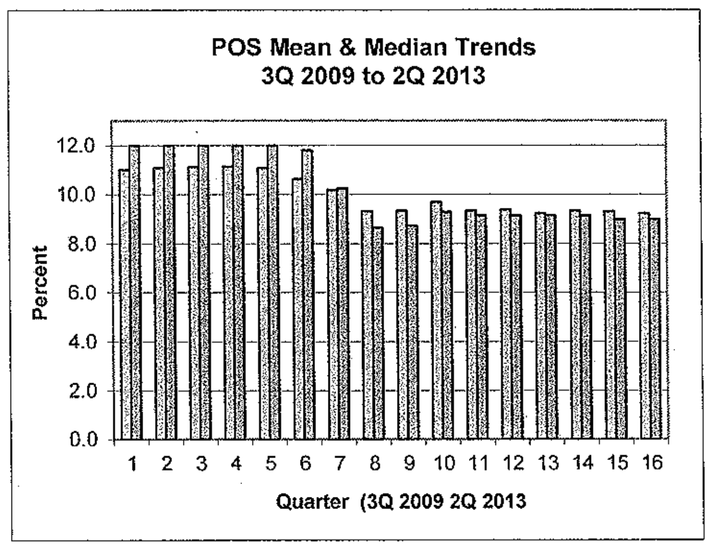
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

POS Summary for 3Q 2009 to 2Q 2013

									Range of Rates	
	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Low	High
3 Q 2009	13.4	[redacted]	[redacted]	6.5	12.5	12.0	11.0	12.0	6.5	13.4
4 Q 2009	13.4	[redacted]	[redacted]	6.5	12.5	12.0	11.1	12.0	6.5	13.4
1 Q 2010	13.4	[redacted]	[redacted]	6.5	13.4	12.0	11.1	12.0	6.5	13.4
2 Q 2010	13.4	[redacted]	[redacted]	6.5	13.4	12.0	11.1	12.0	6.5	13.4
3 Q 2010	13.4	[redacted]	[redacted]	6.5	13.4	12.0	11.1	12.0	6.5	13.4
4 Q 2010	12.5	[redacted]	[redacted]	6.5	11.6	12.0	10.6	11.8	6.5	12.5
1 Q 2011	12.5	[redacted]	[redacted]	6.5	11.6	10.0	10.2	10.3	6.5	12.5
2 Q 2011	12.5	[redacted]	[redacted]	6.5	11.6	8.0	9.3	8.7	6.5	12.5
3 Q 2011	12.5	[redacted]	[redacted]	6.5	11.6	8.0	9.4	8.8	6.5	12.5
4 Q 2011	12.3	[redacted]	[redacted]	8.0	10.3	9.0	9.7	9.3	8.0	12.3
1 Q 2012	12.0	[redacted]	[redacted]	9.3	10.3	9.0	9.4	9.2	6.5	12.0
2 Q 2012	12.0	[redacted]	[redacted]	9.3	10.3	9.0	9.4	9.2	6.7	12.0
3 Q 2012	12.0	[redacted]	[redacted]	9.3	9.3	9.0	9.2	9.2	6.8	12.0
4 Q 2012	12.0	[redacted]	[redacted]	9.3	9.9	9.0	9.4	9.2	6.9	12.0
1 Q 2013	12.0	[redacted]	[redacted]	8.9	9.9	9.0	9.3	9.0	7.1	12.0
2 Q 2013	11.5	[redacted]	[redacted]	8.9	9.9	9.0	9.2	9.0	7.1	11.5



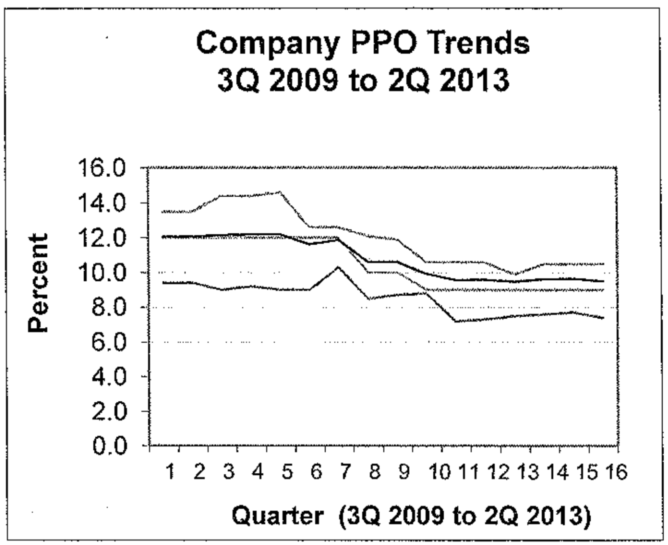


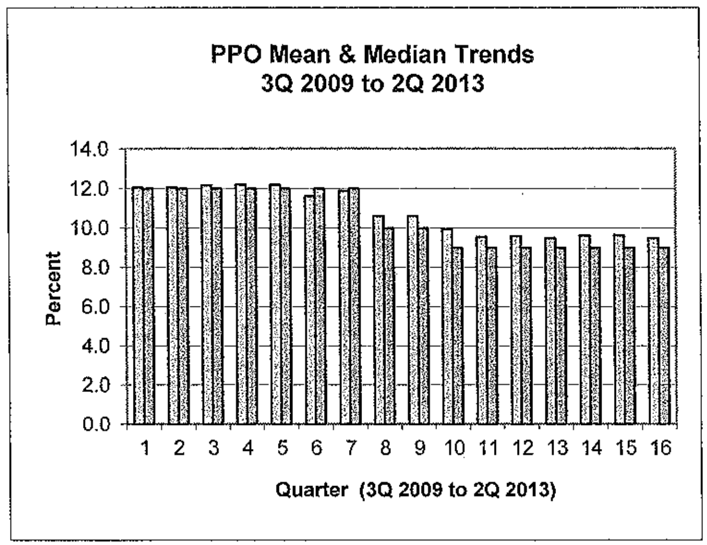
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

PPO Summary for 3Q 2009 to 2Q 2013

	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates	
									Low	High
3 Q 2009	13.4	[redacted]	[redacted]		13.5	12.0	12.1	12.0	9.4	13.5
4 Q 2009	13.4	[redacted]	[redacted]		13.5	12.0	12.1	12.0	9.4	13.5
1 Q 2010	13.4	[redacted]	[redacted]		14.4	12.0	12.2	12.0	9.0	14.4
2 Q 2010	13.4	[redacted]	[redacted]		14.4	12.0	12.2	12.0	9.2	14.4
3 Q 2010	13.4	[redacted]	[redacted]		14.6	12.0	12.2	12.0	9.0	14.6
4 Q 2010	12.5	[redacted]	[redacted]		12.6	12.0	11.6	12.0	9.0	12.6
1 Q 2011	12.5	[redacted]	[redacted]		12.6	12.0	11.9	12.0	10.3	12.6
2 Q 2011	12.5	[redacted]	[redacted]		12.4	10.0	10.6	10.0	8.5	12.5
3 Q 2011	12.5	[redacted]	[redacted]		11.9	10.0	10.6	10.0	8.7	12.5
4 Q 2011	12.3	[redacted]	[redacted]		10.6	9.0	9.9	9.0	8.8	12.3
1 Q 2012	12.0	[redacted]	[redacted]		10.6	9.0	9.6	9.0	7.2	12.0
2 Q 2012	12.0	[redacted]	[redacted]		10.6	9.0	9.6	9.0	7.3	12.0
3 Q 2012	12.0	[redacted]	[redacted]		9.9	9.0	9.5	9.0	7.5	12.0
4 Q 2012	12.0	[redacted]	[redacted]		10.5	9.0	9.6	9.0	7.6	12.0
1 Q 2013	12.0	[redacted]	[redacted]		10.5	9.0	9.6	9.0	7.7	12.0
2 Q 2013	11.5	[redacted]	[redacted]		10.5	9.0	9.5	9.0	7.4	11.5



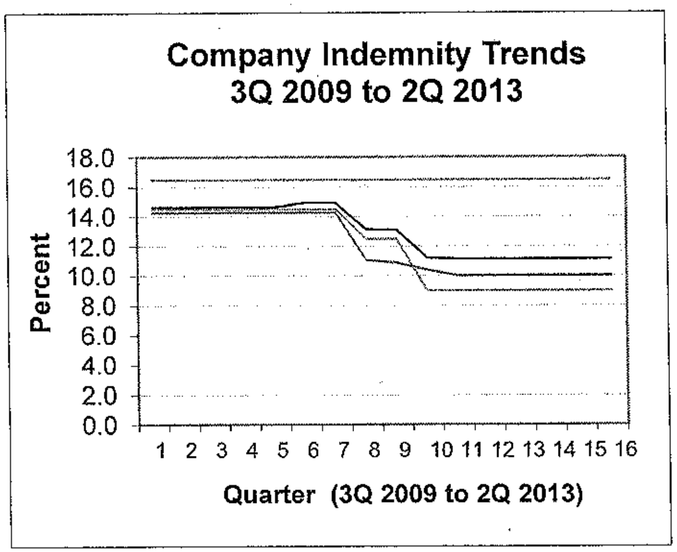


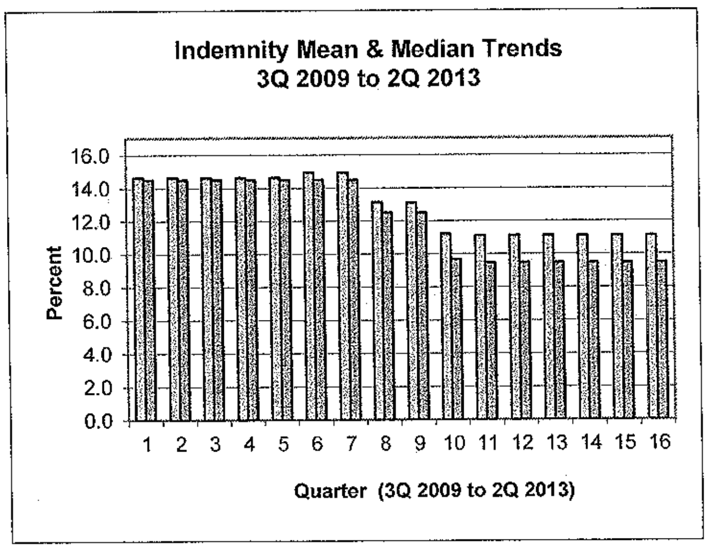
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Indemnity Summary for 3Q 2009 to 2Q 2013

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2009	13.4	[illegible]	[illegible]		16.5	14.5	14.6	14.5	13.4	16.5
4 Q 2009	13.4	[illegible]	[illegible]		16.5	14.5	14.6	14.5	13.4	16.5
1 Q 2010	13.4	[illegible]	[illegible]		16.5	14.5	14.6	14.5	13.4	16.5
2 Q 2010	13.4	[illegible]	[illegible]		16.5	14.6	14.6	14.5	13.4	16.5
3 Q 2010	13.4	[illegible]	[illegible]		16.5	14.5	14.6	14.5	13.4	16.5
4 Q 2010		[illegible]	[illegible]		16.5	14.5	15.0	14.5	14.3	16.5
1 Q 2011		[illegible]	[illegible]		16.5	14.5	15.0	14.5	14.3	16.5
2 Q 2011		[illegible]	[illegible]		16.5	12.5	13.1	12.5	11.1	16.5
3 Q 2011		[illegible]	10.9		16.5	12.5	13.1	12.5	10.9	16.5
4 Q 2011		9.0	10.4		16.5	9.0	11.2	9.7	9.0	16.5
1 Q 2012		[illegible]	10.0		16.5	9.0	11.1	9.5	9.0	16.5
2 Q 2012		9.0	10.0		16.5	9.0	11.1	9.5	9.0	16.5
3 Q 2012		9.0	10.0		16.5	9.0	11.1	9.5	9.0	16.5
4 Q 2012		9.0	10.0		16.5	9.0	11.1	9.5	9.0	16.5
1 Q 2013		9.0	10.0		16.5	9.0	11.1	9.5	9.0	16.5
2 Q 2013		9.0	10.0		16.5	9.0	11.1	9.5	9.0	16.5



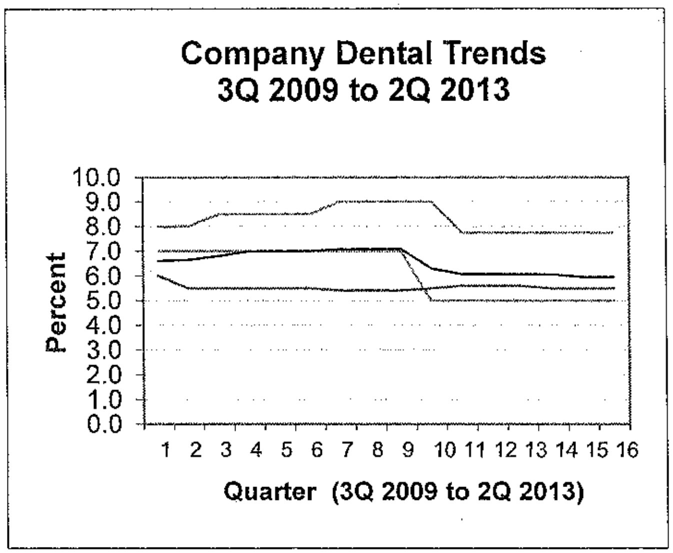


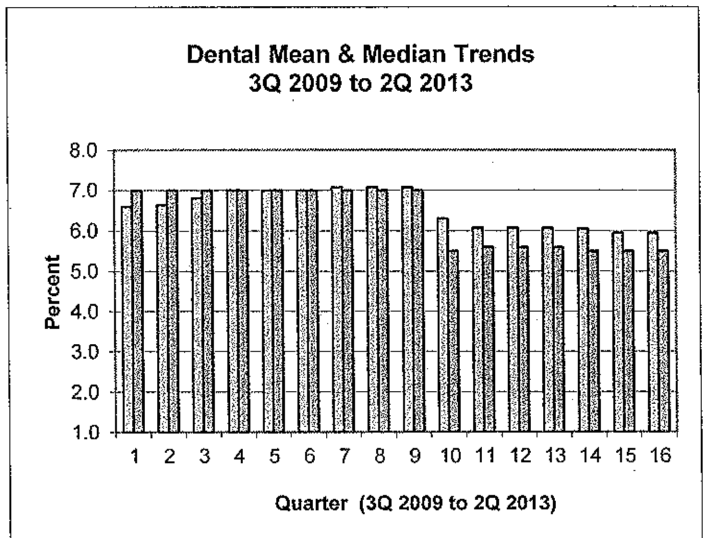
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Dental Summary for 3Q 2009 to 2Q 2013

									Range of Rates	
	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Low	High
3 Q 2009	5.0	[redacted]	[redacted]		8.0	7.0	6.6	7.0	5.0	8.0
4 Q 2009	5.7	[redacted]	[redacted]		8.0	7.0	6.6	7.0	5.5	8.0
1 Q 2010	6.0	[redacted]	[redacted]		8.5	7.0	6.8	7.0	5.5	8.5
2 Q 2010	7.0	[redacted]	[redacted]		8.5	7.0	7.0	7.0	5.5	8.5
3 Q 2010	7.0	[redacted]	[redacted]		8.5	7.0	7.0	7.0	5.5	8.5
4 Q 2010	7.0	[redacted]	[redacted]		8.5	7.0	7.0	7.0	5.5	8.5
1 Q 2011	7.0	[redacted]	[redacted]		9.0	7.0	7.1	7.0	5.4	9.0
2 Q 2011	7.0	[redacted]	[redacted]		9.0	7.0	7.1	7.0	5.4	9.0
3 Q 2011	7.0	[redacted]	[redacted]		9.0	7.0	7.1	7.0	5.4	9.0
4 Q 2011	7.0	[redacted]	[redacted]		9.0	5.0	6.3	5.5	5.0	9.0
1 Q 2012	7.0	[redacted]	[redacted]		7.75	5.0	6.1	5.6	5.0	7.8
2 Q 2012	7.0	[redacted]	[redacted]		7.75	5.0	6.1	5.6	5.0	7.8
3 Q 2012	7.0	[redacted]	[redacted]		7.75	5.0	6.1	5.6	5.0	7.8
4 Q 2012	7.0	[redacted]	[redacted]		7.75	5.0	6.1	5.5	5.0	7.8
1 Q 2013	6.5	[redacted]	[redacted]		7.75	5.0	6.0	5.5	5.0	7.8
2 Q 2013	6.5	[redacted]	[redacted]		7.75	5.0	6.0	5.5	5.0	7.8



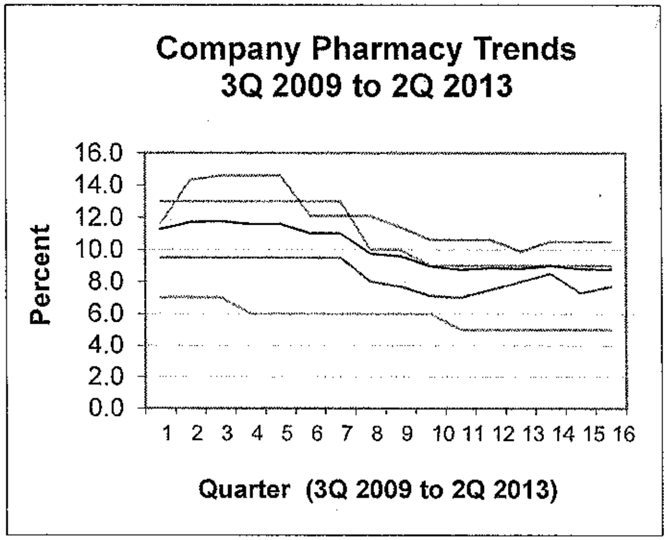


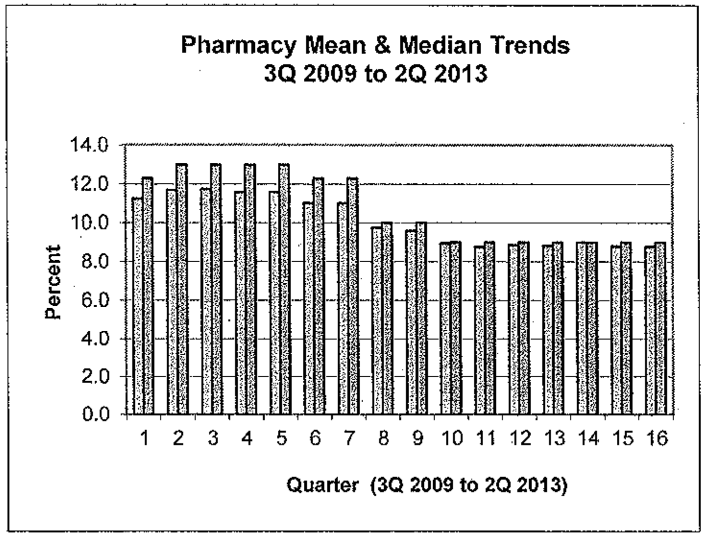
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Pharmacy Summary for 3Q 2009 to 2Q 2013

	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2009	13.4	[redacted]	[redacted]	7.0	11.6	13.0	11.3	12.3	7.0	13.4
4 Q 2009	13.4	[redacted]	[redacted]	7.0	14.3	13.0	11.7	13.0	7.0	14.3
1 Q 2010	13.4	[redacted]	[redacted]	7.0	14.6	13.0	11.8	13.0	7.0	14.6
2 Q 2010	13.4	[redacted]	[redacted]	6.0	14.6	13.0	11.6	13.0	6.0	14.6
3 Q 2010	13.4	[redacted]	[redacted]	6.0	14.6	13.0	11.6	13.0	6.0	14.6
4 Q 2010	12.5	[redacted]	[redacted]	6.0	12.1	13.0	11.0	12.3	6.0	13.0
1 Q 2011	12.5	[redacted]	[redacted]	6.0	12.1	13.0	11.0	12.3	6.0	13.0
2 Q 2011	12.5	[redacted]	[redacted]	6.0	12.1	10.0	9.8	10.0	6.0	12.5
3 Q 2011	12.5	[redacted]	[redacted]	6.0	11.4	10.0	9.6	10.0	6.0	12.5
4 Q 2011	12.0	[redacted]	[redacted]	6.0	10.6	9.0	9.0	9.0	6.0	12.0
1 Q 2012	12.0	[redacted]	[redacted]	5.0	10.6	9.0	8.8	9.0	5.0	12.0
2 Q 2012	12.0	[redacted]	[redacted]	5.0	10.6	9.0	8.9	9.0	5.0	12.0
3 Q 2012	12.0	[redacted]	[redacted]	5.0	9.9	9.0	8.8	9.0	5.0	12.0
4 Q 2012	12.0	[redacted]	[redacted]	5.0	10.5	9.0	9.0	9.0	5.0	12.0
1 Q 2013	12.0	[redacted]	[redacted]	5.0	10.5	9.0	8.8	9.0	5.0	12.0
2 Q 2013	11.5	[redacted]	[redacted]	5.0	10.5	9.0	8.8	9.0	5.0	11.5



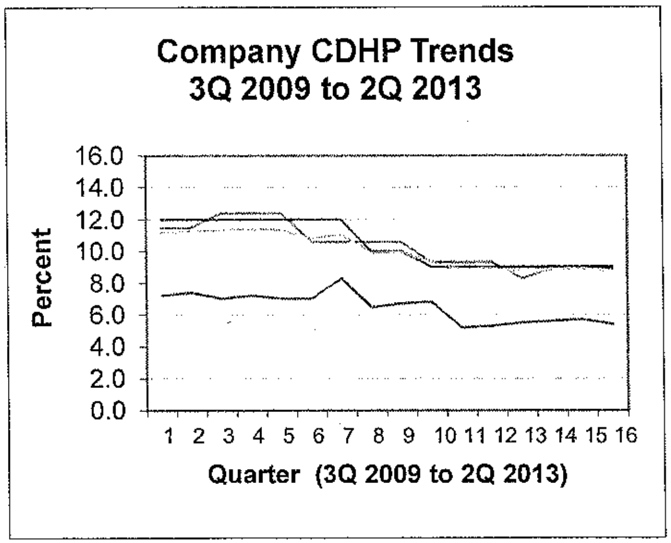


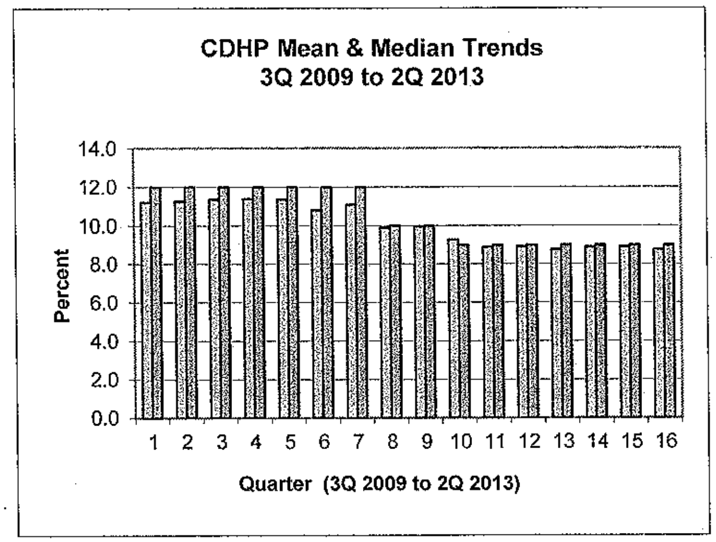
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

CDHP Summary for 3Q 2009 to 2Q 2013

	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2009	13.4	[redacted]	[redacted]		11.5	12.0	11.2	12.0	7.2	13.4
4 Q 2009	13.4	[redacted]	[redacted]		11.5	12.0	11.3	12.0	7.4	13.4
1 Q 2010	13.4	[redacted]	[redacted]		12.4	12.0	11.4	12.0	7.0	13.4
2 Q 2010	13.4	[redacted]	[redacted]		12.4	12.0	11.4	12.0	7.2	13.4
3 Q 2010	13.4	[redacted]	[redacted]		12.4	12.0	11.4	12.0	7.0	13.4
4 Q 2010	12.5	[redacted]	[redacted]		10.6	12.0	10.8	12.0	7.0	12.5
1 Q 2011	12.5	[redacted]	[redacted]		10.6	12.0	11.1	12.0	8.3	12.5
2 Q 2011	12.5	[redacted]	[redacted]		10.6	10.0	9.9	10.0	6.5	12.5
3 Q 2011	12.5	[redacted]	[redacted]		10.6	10.0	10.0	10.0	6.7	12.5
4 Q 2011	12.3	[redacted]	[redacted]		9.3	9.0	9.3	9.0	6.8	12.3
1 Q 2012	12.0	[redacted]	[redacted]		9.3	9.0	8.9	9.0	5.2	12.0
2 Q 2012	12.0	[redacted]	[redacted]		9.3	9.0	8.9	9.0	5.3	12.0
3 Q 2012	12.0	[redacted]	[redacted]		8.3	9.0	8.8	9.0	5.5	12.0
4 Q 2012	12.0	[redacted]	[redacted]		8.9	9.0	8.9	9.0	5.6	12.0
1 Q 2013	12.0	[redacted]	[redacted]		8.9	9.0	8.9	9.0	5.7	12.0
2 Q 2013	11.5	[redacted]	[redacted]		8.9	9.0	8.8	9.0	5.4	11.5



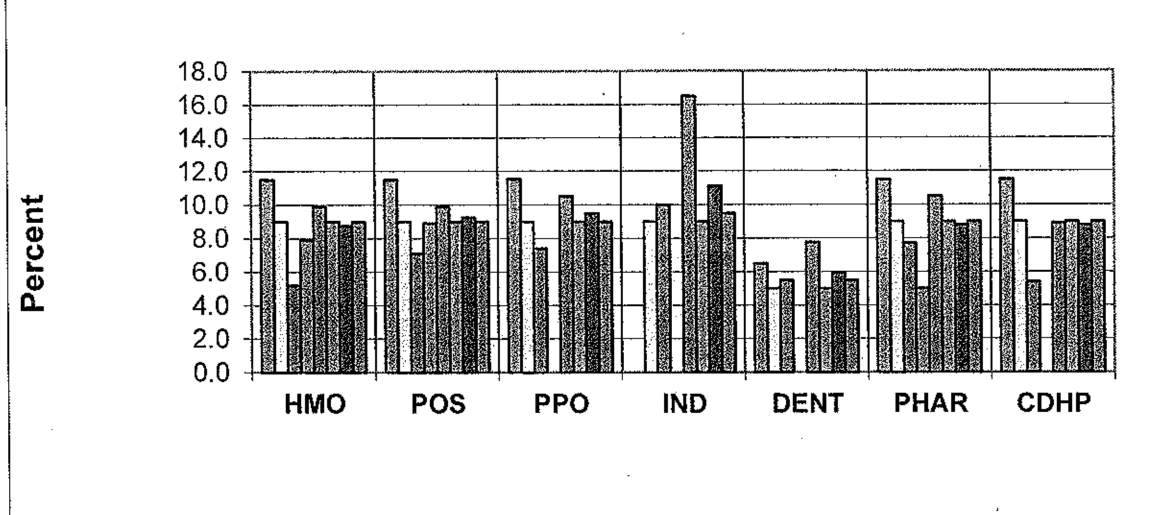


LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Annual Medical Trends Being Used for 2nd Quarter 2013

	Company C	Company D	Company E	Company F	Company G	Company I	Mean/Ave	Median	Range of Rates	
									Low	High
HMO	11.5	9.0	5.2	7.9	9.9	9.0	8.8	9.0	5.2	[illegible]
POS	11.5	9.0	7.1	8.9	9.9	9.0	9.2	9.0	7.1	[illegible]
PPO	11.5	9.0	7.4		10.5	9.0	9.5	9.0	7.4	[illegible]
Indemnity		9.0	10.0		16.5	9.0	11.1	9.5	9.0	[illegible]
Dental	6.5	5.0	5.5		7.75	5.0	6.0	5.5	5.0	[illegible]
Pharmacy	11.5	9.0	7.7	5.0	10.5	9.0	8.8	9.0	5.0	[illegible]
CDHP	11.5	9.0	5.4		8.9	9.0	8.8	9.0	5.4	[illegible]



2013 Medical Trends as of 2Q 2013

Schedule (JCZ-R) - 5
Adjustment No. 9

Delmarva Power & Light
January 2013 to June 2013 Actual Reliability Closings - Gas
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) $
1	**Rate Base**	
2	Plant in Service	
3	Actual reliability closings January 2013 - June 2013	$9,179,266
4	Actual retirements January 2013 - June 2013	($3,620,753)
5	Adjustment to Plant in Service	$5,558,513
6		
7	Depreciation reserve	
8	Actual retirements January 2013 - June 2013	($3,620,753)
9	Depreciation expense	$76,447
10	Adjustment to Depreciation Reserve	($3,544,307)
11		
12	Net Plant	$9,102,819
13		
14	Deferred Taxes	($901,878)
15	Adjustment to Deferred Taxes for NOL Offset	$901,878
16		
17	Total Rate Base	$9,102,819
18		
19	**Earnings**	
20	Depreciation Expense	
21	Actual reliability closings January 2013 - June 2013	$252,486
22	Actual retirements January 2013 - June 2013	($99,593)
23	Adjustment to Depreciation	$152,893
24		
25	State Income Tax	($399,298)
26	Federal Income Tax	($1,466,617)
27	Deferred State Income Tax	$385,996
28	Deferred Federal Income Tax	$1,417,760
29		
30	Operating Expense	$90,735
31		
32	Operating Income	($90,735)
33		
34	Total Earnings	($90,735)

Delmarva Power & Light
July 2013 to December 2013 Forecasted Reliability Closings - Gas
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) $
1	**Rate Base**	
2	Plant in Service	
3	Forecasted reliability closings July 2013 - December 2013	$9,320,143
4	Forecasted retirements July 2013 - December 2013	($1,800,000)
5	Adjustment to Plant in Service	$7,520,143
6		
7	Depreciation reserve	
8	Forecasted retirements July 2013 - December 2013	($1,800,000)
9	Depreciation expense	$103,425
10	Adjustment to Depreciation Reserve	($1,696,575)
11		
12	Net Plant	$9,216,718
13		
14	Deferred Taxes	($905,229)
15	Adjustment to Deferred Taxes for NOL Offset	$905,229
16		
17	Total Rate Base	$9,216,718
18		
19	**Earnings**	
20	Depreciation Expense	
21	Forecasted reliability closings July 2013 - December 2013	$256,361
22	Forecasted retirements July 2013 - December 2013	($49,511)
23	Adjustment to Depreciation	$206,850
24		
25	State Income Tax	($405,426)
26	Federal Income Tax	($1,489,126)
27	Deferred State Income Tax	$387,430
28	Deferred Federal Income Tax	$1,423,027
29		
30	Operating Expense	$122,755
31		
32	Operating Income	($122,755)
33		
34	Total Earnings	($122,755)

Schedule (JCZ-R) - 5.2
Adjustment Nos. 9 & 9A

Delmarva Power & Light
Gas Delivery 2013 Actual & Projected Closings
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Project	(3) Actual January 2013	(4) Actual February 2013	(5) Actual March 2013	(6) Actual April 2013	(7) Actual May 2013	(8) Actual June 2013	(9) Actual Jan - Jun 2013
1	RGCR-1:Gas Service Renewals	$ 144,331	$ 425,619	$ 204,820	$ 471,937	$ 1,462,073	$ 265,746	$ 2,974,527
2	RGCR-2:Cast Iron Renewals	$ 287,703	$ 61,072	$ 182,040	$ 748,526	$ 247,615	$ 71,058	$ 1,598,014
3	RGCR-3:Steel Main Renewals	$ 64,695	$ 142,333	$ 196,287	$ 13,466	$ 63,110	$ 14,753	$ 494,644
4	RGCR-6:Cathodic Protection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	RGCR-12:Transmission Main Renewal	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	RGCR-14:Plastic Main Renewal	$ 12,713	$ 17,306	$ 28,097	$ 17,318	$ 58,367	$ 11,410	$ 145,211
7	RGCR-15:Gas Reimbursable	$ (3,889)	$ 456	$ 21,626	$ 15,366	$ 3,413	$ 907	$ 37,878
8	RGEF-2:Gas Equipment & Facilities	$ 15,478	$ 46,073	$ 14,204	$ (25)	$ 257,503	$ -	$ 333,232
9	RGHW-1:Minor Highway Relocates	$ (6)	$ 162,122	$ -	$ 30	$ (165)	$ 249,555	$ 411,537
10	RGMR-2:Gas Meter Purchases	$ 495,639	$ 224,983	$ (3,325)	$ 413,659	$ 454,399	$ 353,743	$ 1,939,099
11	RGUP-1:Capacity & Regulator	$ 16,972	$ 436,289	$ 386,041	$ 45,550	$ 278,326	$ 81,946	$ 1,245,123
12	RITG20:GAS IT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13								
14	Total	$ 1,033,637	$ 1,516,253	$ 1,029,789	$ 1,725,827	$ 2,824,641	$ 1,049,119	$ 9,179,266
14								
14		Forecasted	Forecasted	Forecasted	Forecasted	Forecasted	Forecasted	Forecasted
16	Project	July 2013	August 2013	September 2013	October 2013	November 2013	December 2013	Jul - Dec 2013
17								
18	RGCR-1:Gas Service Renewals	$ 709,545	$ 650,954	$ 540,082	$ 520,568	$ 448,599	$ 328,844	$ 3,198,592
19	RGCR-2:Cast Iron Renewals	$ 798,830	$ 900,976	$ 597,466	$ 410,523	$ 199,962	$ 180,820	$ 3,088,577
20	RGCR-3:Steel Main Renewals	$ 100,733	$ 80,933	$ 118,830	$ 95,383	$ 44,133	$ 53,352	$ 493,364
21	RGCR-6:Cathodic Protection	$ 9,490	$ 12,867	$ 12,331	$ 9,628	$ 13,361	$ 12,120	$ 69,797
22	RGCR-12:Transmission Main Renewal	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	RGCR-14:Plastic Main Renewal	$ 35,256	$ 30,350	$ 28,983	$ 34,135	$ 30,647	$ 31,515	$ 190,886
24	RGCR-15:Gas Reimbursable	$ 4,789	$ 4,777	$ 4,770	$ -	$ 4,385	$ 4,474	$ 23,195
25	RGEF-2:Gas Equipment & Facilities	$ 151,616	$ 162,713	$ 99,942	$ 53,401	$ 55,316	$ 25,256	$ 548,244
26	RGHW-1:Minor Highway Relocates	$ 100,733	$ 75,874	$ 74,833	$ 100,397	$ 49,431	$ 55,138	$ 456,406
27	RGMR-2:Gas Meter Purchases	$ 11,096	$ 238,737	$ 197,634	$ 10,885	$ 219,953	$ -	$ 678,305
28	RGUP-1:Capacity & Regulator	$ 70,416	$ 101,166	$ 99,958	$ 150,596	$ 24,715	$ 31,279	$ 478,130
29	RITG20:GAS IT	$ 15,994	$ 21,031	$ 15,405	$ 21,010	$ 10,976	$ 10,231	$ 94,647
30								
31	Total	$ 2,008,498	$ 2,280,378	$ 1,790,234	$ 1,406,526	$ 1,101,478	$ 733,029	$ 9,320,143

Delmarva Power & Light
Gas Delivery 2013 Actual Closings
12+0 Months Ending December 31, 2012

Schedule (JCZ-R) - 5.3
Adjustment Nos. 9

(1) Line No.	(2) Project #	Project	(3) Actual January 2013	(4) Actual February 2013	(5) Actual March 2013	(6) Actual April 2013	(7) Actual May 2013	(8) Actual June 2013	(9) Actual Jan - Jun 2013
	RGCR-1:Gas Service Renewals								
1	RGCR-1.1	Gas Service Renewals a/c Leak	$ 44,815	$ 137,710	$ 98,250	$ 108,939	$ 145,408	$ 67,550	$ 602,672
2	RGCR-1.2	Gas Service Renewals a/c Customer	$ 6,215	$ 225	$ 1,654	$ 26,782	$ 2,911	$ 11,713	$ 49,500
3	RGCR-1.3	Gas Service Retirement		$ 5,090	$ 3,194	$ 1,445	$ 94		$ 9,823
4	RGCR-1.4	Gas Service Retirement a/c Demoliti							$ -
5	RGCR-1.5	Gas Service Renewal a/c Engineering	$ 66,225	$ 55,383	$ 82,060	$ 96,232	$ 79,376	$ 181,692	$ 560,968
6	RGCR-1.6	Gas Service Renewal in Main Project	$ 27,076	$ 227,211	$ 19,662	$ 238,539	$ 1,234,285	$ 4,792	$ 1,751,565
7	RGCR-1	Total	$ 144,331	$ 425,619	$ 204,820	$ 471,937	$ 1,462,073	$ 265,746	$ 2,974,527
8									
9	RGCR-2:Cast Iron Renewals								
10	RGCR-2.1	Gas C.I. Main Renewal - Installs	$ 283,241	$ 3,067	$ 87,559	$ 684,729	$ 179,237	$ 58,029	$ 1,295,862
11	RGCR-2.2	Gas Bell Joint Encapsulation	$ 4,462	$ 58,005	$ 94,481	$ 63,796	$ 68,378	$ 13,029	$ 302,152
12	RGCR-2.3	Gas C.I. Main Renewal - Retirement							$ -
13	RGCR-2.4	Gas Service - Installation							$ -
14	RGCR-2	Total	$ 287,703	$ 61,072	$ 182,040	$ 748,526	$ 247,615	$ 71,058	$ 1,598,014
15									
16	RGCR-3:Steel Main Renewals								
17	RGCR-3.1	Gas Steel Main Renewals - Install	$ 61,759	$ 120,954	$ 189,350	$ 10,358	$ 37,626	$ 1,549	$ 421,596
18	RGCR-3.2	Gas Steel Main Renewals - Retire						$ 6,866	$ 6,866
19	RGCR-6.2	CP Installation Distribution System	$ 2,936	$ 13,585	$ 6,908	$ 3,108	$ 25,484	$ 6,339	$ 58,359
20	RGCR-6.3	CP Installation Service System		$ 7,795	$ 29				$ 7,823
21	RGCR-3	Total	$ 64,695	$ 142,333	$ 196,287	$ 13,466	$ 63,110	$ 14,753	$ 494,644
22									
23	RGMR-6:Cathodic Protection								
24	RGCR-6.1	CP Installation Transmission System							$ -
25	RGCR-6.1	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26									
27	RGCR-14:Plastic Main Renewal								
28	RGCR-14.1	Plastic Main Install	$ 12,713	$ 17,306	$ 28,097	$ 17,318	$ 58,367	$ 11,410	$ 145,211
29	RGCR-14.2	Plastic Main Retirement							$ -
30	RGCR-14	Total	$ 12,713	$ 17,306	$ 28,097	$ 17,318	$ 58,367	$ 11,410	$ 145,211
31									
32	RGCR-15:Gas Reimbursable								
33	RGCR-15.1	Capital Uncollectible Claims - Gas							$ -
34	RGCR-15.2	Capital Unbillable Claims - Gas							$ -
35	RGCR-15.4	Capital Recoveries - Gas	$ (4,151)		$ (695)		$ (771)		$ (5,617)
36	RGCR-15.5	Capital Uncoll/Unbill Claims - Gas	$ 262	$ 456	$ 22,321	$ 15,366	$ 4,184	$ 907	$ 43,495
37	RGCR-15	Total	$ (3,889)	$ 456	$ 21,626	$ 15,366	$ 3,413	$ 907	$ 37,878
38									
39	RGEF-2:Gas Equipment & Facilities								
40	RGEF-2	Regulator/Valves - Distribution							$ -
41	RGEF-2	HL Elctronic Recorder ERX - Dist	$ 1,042	$ 197	$ 510	$ (6)			$ 1,743
42	RGEF-2	TH Electronic Recorder ERX - Dist	$ 375		$ 1,530	$ (19)			$ 1,886
43	RGEF-2	Remote Recifiier Read & Control - Dist							$ -
44	RGEF-2	Control Room Recorders - Install							$ -
45	RGEF-2	LNG HVAC							$ -
46	RGEF-2	Install TT-8 Jordan Actuator - Trans		$ 11,773					$ 11,773
47	RGEF-2	Gas Plant & Facilities							$ -
48	RGEF-2	Ridge Road Lighting System							$ -
49	RGEF-2	Remote Recifiier Read & Control -Trans	$ 27,190						$ 27,190
50	RGEF-2	Regulator/Valves - Transmission	$ (13,356)	$ 34,101			$ 6,638		$ 27,383
51	RGEF-2	Gas Tools & Equipment 2012	$ 226	$ 1	$ 12,164				$ 12,390
52	RGEF-2	Motor Control Center for LNG (MCC)					$ 250,865		$ 250,865
53	RGEF-2	Total	$ 15,478	$ 46,073	$ 14,204	$ (25)	$ 257,503	$ -	$ 333,232
54									
55	RGHW-1:Minor Highway Relocates								
56	RGHW-1.3	Highway Distribution Installation		$ 162,122		$ 24	$ (165)	$ 249,555	$ 411,537
57	RGHW-1.5	Highway Service Installation							$ -
58	RGHW-1.8	Highway Distribution Reimbursable	$ (6)			$ 6			$ -
59	RGHW-1.9	Highway Service Reimbursable							$ -
60	RGHW-1	Total	$ (6)	$ 162,122	$ -	$ 30	$ (165)	$ 249,555	$ 411,537
61									
62	RGMR-2:Gas Meter Purchases								
63	RGMR-1.1	Gas Meters							$ -
64	RGMR-2.1	Gas Meter Purchases	$ 495,639	$ 224,983	$ (3,325)	$ 413,659	$ 454,399	$ 353,743	$ 1,939,099
65	RGMR-2.2	Gas Meters - Removal							$ -
66	RGMR-2	Total	$ 495,639	$ 224,983	$ (3,325)	$ 413,659	$ 454,399	$ 353,743	$ 1,939,099
67									
68	RGMR-12:Gas Transmission								
69	RGCR-12.1	Transmission Main Renewal							$ -
70	RGCR-12	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71									
72	RGUP-1:Capacity & Regulator								
73	RGUP-1.1	Gas Capacity Improvements		$ 214,061	$ 53,135	$ 3,047			$ 270,244
74	RGUP-1.1.3	Distribution Improvements Install	$ 184	$ 220,649	$ 332,906	$ 42,502	$ 15,544	$ 79,302	$ 691,088
75	RGUP-1.1.5	Distribution Easements							$ -
76	RGUP-1.2.1	Gas Dist Regulator Improvements	$ 16,788	$ 1,579			$ 262,782	$ 2,644	$ 283,792
77	RGUP-1	Total	$ 16,972	$ 436,289	$ 386,041	$ 45,550	$ 278,326	$ 81,946	$ 1,245,123
78									
79	RITG20:GAS IT								
80	RITG20	Gas Hardware/Software							$ -
81	RITG20	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82									
83		Total - Reliability Plant Closings	$ 1,033,637	$ 1,516,253	$ 1,029,789	$ 1,725,827	$ 2,824,641	$ 1,049,119	$ 9,179,266

Delmarva Power & Light
Gas Delivery 2013 Forecasted Closings
12+0 Months Ending December 31, 2012

Schedule (JCZ-R) - 5.4
Adjustment Nos. 9A

(1) Line No.	(2) Project #	Project	(3) Forecasted July 2013	(4) Forecasted August 2013	(5) Forecasted September 2013	(6) Forecasted October 2013	(7) Forecasted November 2013	(8) Forecasted December 2013	(9) Forecasted Jul - Dec 2013
	RGCR-1:Gas Service Renewals								
1	RGCR-1.1	Gas Service Renewals a/c Leak	$ 100,000	$ 100,000	$ 50,000		$ 60,000		$ 310,000
2	RGCR-1.2	Gas Service Renewals a/c Customer	$ 10,000	$ 10,000	$ 10,000		$ 30,000		$ 60,000
3	RGCR-1.3	Gas Service Retirement							$ -
4	RGCR-1.4	Gas Service Retirement a/c Demoliti							$ -
5	RGCR-1.5	Gas Service Renewal a/c Engineering	$ 150,000	$ 150,000	$ 100,000	$ 100,000	$ 150,000	$ 200,000	$ 850,000
6	RGCR-1.6	Gas Service Renewal in Main Project	$ 449,545	$ 390,954	$ 380,082	$ 420,568	$ 208,599	$ 128,844	$ 1,976,592
7	RGCR-1	Total	$ 709,545	$ 650,954	$ 540,082	$ 520,568	$ 448,599	$ 328,844	$ 3,196,592
8									
9	RGCR-2:Cast Iron Renewals								
10	RGCR-2.1	Gas C.I. Main Renewal - Installs	$ 748,830	$ 800,976	$ 547,466	$ 410,523	$ -	$ 180,820	$ 2,688,615
11	RGCR-2.2	Gas Bell Joint Encapsulation	$ 50,000	$ 100,000	$ 50,000		$ 199,962		$ 399,962
12	RGCR-2.3	Gas C.I. Main Renewal - Retirement							$ -
13	RGCR-2.4	Gas Service - Installation							$ -
14	RGCR-2	Total	$ 798,830	$ 900,976	$ 597,466	$ 410,523	$ 199,962	$ 180,820	$ 3,088,577
15									
16	RGCR-3:Steel Main Renewals								
17	RGCR-3.1	Gas Steel Main Renewals - Install	$ 100,733	$ 80,933	$ 98,830	$ 85,383	$ 34,133	$ 33,352	$ 433,364
18	RGCR-3.2	Gas Steel Main Renewals - Retire							$ -
19	RGCR-6.2	CP Installation Distribution System			$ 20,000	$ 10,000	$ 10,000	$ 20,000	$ 60,000
20	RGCR-6.3	CP Installation Service System							$ -
21	RGCR-3	Total	$ 100,733	$ 80,933	$ 118,830	$ 95,383	$ 44,133	$ 53,352	$ 493,364
22									
23	RGMR-6:Cathodic Protection								
24	RGCR-6.1	CP Installation Transmission System	$ 9,490	$ 12,867	$ 12,331	$ 9,628	$ 13,361	$ 12,120	$ 69,797
25	RGCR-6.1	Total	$ 9,490	$ 12,867	$ 12,331	$ 9,628	$ 13,361	$ 12,120	$ 69,797
26									
27	RGCR-14:Plastic Main Renewal								
28	RGCR-14.1	Plastic Main Install	$ 35,256	$ 30,350	$ 28,983	$ 34,135	$ 30,647	$ 31,515	$ 190,886
29	RGCR-14.2	Plastic Main Retirement							$ -
30	RGCR-14	Total	$ 35,256	$ 30,350	$ 28,983	$ 34,135	$ 30,647	$ 31,515	$ 190,886
31									
32	RGCR-15:Gas Reimbursable								
33	RGCR-15.1	Capital Uncollectible Claims - Gas							$ -
34	RGCR-15.2	Capital Unbillable Claims - Gas							$ -
35	RGCR-15.4	Capital Recoveries - Gas							$ -
36	RGCR-15.5	Capital Uncoll/Unbill Claims - Gas	$ 4,789	$ 4,777	$ 4,770	$ -	$ 4,385	$ 4,474	$ 23,195
37	RGCR-15	Total	$ 4,789	$ 4,777	$ 4,770	$ -	$ 4,385	$ 4,474	$ 23,195
38									
39	RGEF-2:Gas Equipment & Facilities								
40	RGEF-2	Regulator/Valves - Distribution							$ -
41	RGEF-2	HL Elctronic Recorder ERX - Dist							$ -
42	RGEF-2	TH Electronic Recorder ERX - Dist							$ -
43	RGEF-2	Remote Recifiier Read & Control - Dist							$ -
44	RGEF-2	Control Room Recorders - Install							$ -
45	RGEF-2	LNG HVAC							$ -
46	RGEF-2	Install TT-8 Jordan Actuator - Trans							$ -
47	RGEF-2	Gas Plant & Facilities	$ 151,616	$ 162,713	$ 99,942		$ 55,316	$ 25,256	$ 494,843
48	RGEF-2	Ridge Road Lighting System							$ -
49	RGEF-2	Remote Recifiier Read & Control -Trans							$ -
50	RGEF-2	Regulator/Valves - Transmission							$ -
51	RGEF-2	Gas Tools & Equipment 2012				$ 53,401			$ 53,401
52	RGEF-2	Motor Control Center for LNG (MCC)							$ -
53	RGEF-2	Total	$ 151,616	$ 162,713	$ 99,942	$ 53,401	$ 55,316	$ 25,256	$ 548,244
54									
55	RGHW-1:Minor Highway Relocates								
56	RGHW-1.3	Highway Distribution Installation	$ 100,733	$ 75,874	$ 74,833	$ 100,397	$ 49,431	$ 55,138	$ 456,406
57	RGHW-1.5	Highway Service Installation							$ -
58	RGHW-1.8	Highway Distribution Reimbursable							$ -
59	RGHW-1.9	Highway Service Reimbursable							$ -
60	RGHW-1	Total	$ 100,733	$ 75,874	$ 74,833	$ 100,397	$ 49,431	$ 55,138	$ 456,406
61									
62	RGMR-2:Gas Meter Purchases								
63	RGMR-1.1	Gas Meters	$ 11,096	$ 238,737	$ 197,634	$ 10,885	$ 219,953	$ -	$ 678,305
64	RGMR-2.1	Gas Meter Purchases							$ -
65	RGMR-2.2	Gas Meters - Removal							$ -
66	RGMR-2	Total	$ 11,096	$ 238,737	$ 197,634	$ 10,885	$ 219,953	$ -	$ 678,305
67									
68	RGMR-12:Gas Transmission								
69	RGCR-12.1	Transmission Main Renewal							$ -
70	RGCR-12	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71									
72	RGUP-1:Capacity & Regulator								
73	RGUP-1.1	Gas Capacity Improvements					$ 24,715		$ 24,715
74	RGUP-1.1.3	Distribution Improvements Install	$ 70,416	$ 101,166	$ 99,958	$ 150,596		$ 31,279	$ 453,415
75	RGUP-1.1.5	Distribution Easements							$ -
76	RGUP-1.2.1	Gas Dist Regulator Improvements							$ -
77	RGUP-1	Total	$ 70,416	$ 101,166	$ 99,958	$ 150,596	$ 24,715	$ 31,279	$ 478,130
78									
79	RITG20:GAS IT								
80	RITG20	Gas Hardware/Software	$ 15,994	$ 21,031	$ 15,405	$ 21,010	$ 10,976	$ 10,231	$ 94,647
81	RITG20	Total	$ 15,994	$ 21,031	$ 15,405	$ 21,010	$ 10,976	$ 10,231	$ 94,647
82									
83	Total - Reliability Plant Closings		$ 2,008,498	$ 2,280,378	$ 1,790,234	$ 1,406,526	$ 1,101,478	$ 733,029	$ 9,320,143

Delmarva Power
Remove Bloom-Related Incremental Rate Base - Gas
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) $
1	**Rate Base**	
2	Plant in Service	
3	Brookside Unit	($229,284)
4	Red Lion Unit	($157,653)
5	Adjustment to Plant in Service	($386,936)
6		
7	Depreciation reserve	
8	Brookside Unit	($2,138)
9	Red Lion Unit	($123)
10	Adjustment to Depreciation Reserve	($2,261)
11		
12	Net Plant	($384,676)
13		
14	Deferred Taxes	$78,195
15	Adjustment to Deferred Taxes for NOL Offset	($78,195)
16		
17	Total Rate Base	($384,676)
18		
19	**Earnings**	
20	Depreciation Expense	
21	Brookside Unit	($2,138)
22	Red Lion Unit	($123)
23	Adjustment to Depreciation	($2,261)
24		
25	State Income Tax	$33,663
26	Federal Income Tax	$123,646
27	Deferred State Income Tax	($33,467)
28	Deferred Federal Income Tax	($122,923)
29		
30	Operating Expense	($1,342)
31		
32	Operating Income	$1,342
33		
34	Total Earnings	$1,342

Delmarva Power
AMI Net Plant Additions - Gas
12+0 Months Ending December 2012

(1) Line No.	(2) Item	(3) $
1	**Rate Base**	
2	Proforma Plant in Service	
3	Delmarva Power - IMU	5,957,812
4	Delmarva Power - Communication Equipment	702,000
5	Service Company - IT Hardware and Software	1,398,201
6	Adjustment to Plant in Service	8,058,013
7		
8	Depreciation reserve	
9	Delmarva Power - IMU	443,987
10	Delmarva Power - Communication Equipment	25,071
11	Service Company - IT Hardware and Software	377,490
12	Adjustment to Depreciation Reserve	846,548
13		
14	Net Plant	$7,211,465
15		
16	CWIP	(1,136,366)
17		
18	Deferred Taxes	($676,650)
19	Adjustment to Deferred Taxes for NOL Offset	$676,650
20		
21	Total Rate Base	$6,075,099
22		
23	**Earnings**	
24	Depreciation Expense	
25	Delmarva Power - IMU	387,125
26	Delmarva Power - Communication Equipment	33,429
27	Service Company - IT Hardware and Software	279,712
28	Adjustment to Depreciation	700,266
29		
30	State Income Tax	($350,524)
31	Federal Income Tax	($1,287,469)
32	Deferred State Income Tax	$289,600
33	Deferred Federal Income Tax	$1,063,699
34		
35	Operating Expense	$415,573
36		
37	Operating Income	($415,573)
38		
39	AFUDC	17,300
40		
41	Total Earnings	($398,272)

Schedule (JCZ-R) - 8
Adjustment No. 12

Delmarva Power & Light Company
Normalize Meter Reading Expense- Gas
12 + 0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Amount
1	Remove Meter Reading Expense - SSN Credit	
2	Delaware Gas	$0
3		
4	Income Taxes	
5	State Income Tax	$0
6	Federal Income Tax	$0
7	Total Income Taxes	$0
8		
9	Earnings	$0

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancings - Gas
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Amount	(4) First Mortgage Bonds Aug-93	(5) Demand Rate Bonds Nov-93	(6) Tax Exempt Bonds Sep-00	(7) Tax Exempt Bonds Sep-00
	Total Company	$33,107,672	$702,894	$348,751	$576,741	$1,438,608
1	Gas Amount Refinanced	$4,034,036	$42,174	$20,925	$45,216	$112,787
2	Deferred SIT	($350,961)	($3,669)	($1,820)	($3,934)	($9,812)
3	Deferred FIT	($1,289,076)	($13,477)	($6,687)	($14,449)	($36,041)
4						
5	**Earnings**					
6	Amortization	$215,903	$1,745	$996	$3,014	$5,784
7	DSIT	($18,784)	($152)	($87)	($262)	($503)
8	DFIT	($68,992)	($558)	($318)	($963)	($1,848)
9	Total Expense	$128,128	$1,036	$591	$1,789	$3,432
10	Earnings	($128,128)	($1,036)	($591)	($1,789)	($3,432)
11						
12	**Rate Base**					
13	Amortizable Balance - 12/31/11	$2,095,980	$10,034	$2,823	$11,053	$47,236
14	Amortizable Balance - 12/31/12	$2,119,032	$8,289	$1,827	$8,038	$41,452
15	Average Balance	$2,107,506	$9,162	$2,325	$9,546	$44,344
16						
17	Deferred SIT - 12/31/11	($182,350)	($873)	($246)	($962)	($4,109)
18	Deferred SIT - 12/31/12	($184,356)	($721)	($159)	($699)	($3,606)
19	Average Balance	($183,353)	($797)	($202)	($830)	($3,858)
20						
21	Deferred FIT - 12/31/11	($669,771)	($3,206)	($902)	($3,532)	($15,094)
22	Deferred FIT - 12/31/12	($677,137)	($2,649)	($584)	($2,569)	($13,246)
23	Average Balance	($673,454)	($2,928)	($743)	($3,050)	($14,170)
24						
25	Net Year End Balance	$1,257,540	$4,919	$1,084	$4,770	$24,599
26						
27	Amortization begin date (a)		August-93	November-93	September-00	September-00
28	Amortization period (months)		290	252	180	234
29	Amortization as of 12/31/11		221	218	136	136
30	Amortization as of 12/31/12		233	230	148	148

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Tax Exempt Bonds Sep-00	(4) Tax Exempt Bonds Oct-00	(5) Tax Exempt Bonds Jul-01	(6) Tax Exempt Bonds Jul-01	(7) First Mortgage Bonds Jul-01
	Total Company	$558,772	$235,481	$490,000	$690,000	$3,762,881
1	Gas Amount Refinanced	$43,808	$18,462	$38,416	$54,096	$295,010
2	Deferred SIT	($3,811)	($1,606)	($3,342)	($4,706)	($25,666)
3	Deferred FIT	($13,999)	($5,899)	($12,276)	($17,286)	($94,270)
4						
5	**Earnings**					
6	Amortization	$3,245	$1,086	$1,921	$3,182	$20,702
7	DSIT	($282)	($94)	($167)	($277)	($1,801)
8	DFIT	($1,037)	($347)	($614)	($1,017)	($6,615)
9	Total Expense	$1,926	$644	$1,140	$1,888	$12,286
10	Earnings	($1,926)	($644)	($1,140)	($1,888)	($12,286)
11						
12	**Rate Base**					
13	Amortizable Balance - 12/31/11	$7,031	$6,154	$18,248	$20,684	$77,634
14	Amortizable Balance - 12/31/12	$3,786	$5,068	$16,327	$17,502	$56,932
15	Average Balance	$5,408	$5,611	$17,287	$19,093	$67,283
16						
17	Deferred SIT - 12/31/11	($612)	($535)	($1,588)	($1,799)	($6,754)
18	Deferred SIT - 12/31/12	($329)	($441)	($1,420)	($1,523)	($4,953)
19	Average Balance	($471)	($488)	($1,504)	($1,661)	($5,854)
20						
21	Deferred FIT - 12/31/11	($2,247)	($1,966)	($5,831)	($6,609)	($24,808)
22	Deferred FIT - 12/31/12	($1,210)	($1,619)	($5,217)	($5,593)	($18,193)
23	Average Balance	($1,728)	($1,793)	($5,524)	($6,101)	($21,500)
24						
25	Net Year End Balance	$2,247	$3,008	$9,689	$10,386	$33,786
26						
27	Amortization begin date (a)	September-00	October-00	July-01	July-01	July-01
28	Amortization period (months)	162	204	240	204	171
29	Amortization as of 12/31/11	136	136	126	126	126
30	Amortization as of 12/31/12	148	148	138	138	138

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Medium Term Notes Jul-01	(4) First Mortgage Bonds Jul-01	(5) Medium Term Notes Jul-01	(6) Medium Term Notes Jul-01
	Total Company	$3,058,389	$1,634,283	$1,073,753	($595,660)
1	Gas Amount Refinanced	$239,778	$128,128	$84,182	($46,700)
2	Deferred SIT	($20,861)	($11,147)	($7,324)	$4,063
3	Deferred FIT	($76,621)	($40,943)	($26,900)	$14,923
4					
5	**Earnings**				
6	Amortization	$12,349	$6,225	$5,402	($2,816)
7	DSIT	($1,074)	($542)	($470)	$245
8	DFIT	($3,946)	($1,989)	($1,726)	$900
9	Total Expense	$7,329	$3,694	$3,206	($1,671)
10	Earnings	($7,329)	($3,694)	($3,206)	$1,671
11					
12	**Rate Base**				
13	Amortizable Balance - 12/31/11	$110,113	$62,767	$27,461	($17,131)
14	Amortizable Balance - 12/31/12	$97,763	$56,542	$22,058	($14,315)
15	Average Balance	$103,938	$59,655	$24,759	($15,723)
16					
17	Deferred SIT - 12/31/11	($9,580)	($5,461)	($2,389)	$1,490
18	Deferred SIT - 12/31/12	($8,505)	($4,919)	($1,919)	$1,245
19	Average Balance	($9,043)	($5,190)	($2,154)	$1,368
20					
21	Deferred FIT - 12/31/11	($35,186)	($20,057)	($8,775)	$5,474
22	Deferred FIT - 12/31/12	($31,240)	($18,068)	($7,049)	$4,574
23	Average Balance	($33,213)	($19,063)	($7,912)	$5,024
24					
25	Net Year End Balance	$58,018	$33,555	$13,091	($8,495)
26					
27	Amortization begin date (a)	July-01	July-01	July-01	July-01
28	Amortization period (months)	233	247	187	199
29	Amortization as of 12/31/11	126	126	126	126
30	Amortization as of 12/31/12	138	138	138	138

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Medium Term Notes Jul-01	(4) First Mortgage Bonds Feb-02	(5) Tax Exempt Bonds Jun-02	(6) Tax Exempt Bonds Jun-02
	Total Company	$1,340,233	$1,388,233	$944,292	$1,313,393
1	Gas Amount Refinanced	$105,074	$222,117	$151,087	$210,143
2	Deferred SIT	($9,141)	($19,324)	($13,145)	($18,282)
3	Deferred FIT	($33,576)	($70,978)	($48,280)	($67,151)
4					
5	**Earnings**				
6	Amortization	$4,107	$11,060	$7,523	$12,301
7	DSIT	($357)	($962)	($655)	($1,070)
8	DFIT	($1,312)	($3,534)	($2,404)	($3,931)
9	Total Expense	$2,437	$6,563	$4,465	$7,300
10	Earnings	($2,437)	($6,563)	($4,465)	($7,300)
11					
12	**Rate Base**				
13	Amortizable Balance - 12/31/11	$61,949	$112,441	$78,991	$92,258
14	Amortizable Balance - 12/31/12	$57,842	$101,381	$71,468	$79,957
15	Average Balance	$59,896	$106,911	$75,230	$86,107
16					
17	Deferred SIT - 12/31/11	($5,390)	($9,782)	($6,872)	($8,026)
18	Deferred SIT - 12/31/12	($5,032)	($8,820)	($6,218)	($6,956)
19	Average Balance	($5,211)	($9,301)	($6,545)	($7,491)
20					
21	Deferred FIT - 12/31/11	($19,796)	($35,931)	($25,242)	($29,481)
22	Deferred FIT - 12/31/12	($18,483)	($32,396)	($22,838)	($25,550)
23	Average Balance	($19,140)	($34,163)	($24,040)	($27,516)
24					
25	Net Year End Balance	$34,326	$60,165	$42,413	$47,450
26					
27	Amortization begin date (a)	July-01	February-02	June-02	June-02
28	Amortization period (months)	307	241	241	205
29	Amortization as of 12/31/11	126	119	115	115
30	Amortization as of 12/31/12	138	131	127	127

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) First Mortgage Bonds May-03	(4) Tax Exempt Bonds Aug-03	(5) Trust Preferred May-04	(6) First Mortgage Bonds Jun-05
	Total Company	$1,298,560	$1,347,719	$1,943,173	$4,497,500
1	Gas Amount Refinanced	$207,770	$215,635	$310,908	$719,600
2	Deferred SIT	($18,076)	($18,760)	($27,049)	($62,605)
3	Deferred FIT	($66,393)	($68,906)	($99,351)	($229,948)
4					
5	**Earnings**				
6	Amortization	$16,733	$8,086	$9,591	$35,980
7	DSIT	($1,456)	($704)	($834)	($3,130)
8	DFIT	($5,347)	($2,584)	($3,065)	($11,497)
9	Total Expense	$9,930	$4,799	$5,692	$21,352
10	Earnings	($9,930)	($4,799)	($5,692)	($21,352)
11					
12	**Rate Base**				
13	Amortizable Balance - 12/31/11	$62,749	$147,575	$237,377	$482,732
14	Amortizable Balance - 12/31/12	$46,016	$139,489	$227,786	$446,752
15	Average Balance	$54,383	$143,532	$232,581	$464,742
16					
17	Deferred SIT - 12/31/11	($5,459)	($12,839)	($20,652)	($41,998)
18	Deferred SIT - 12/31/12	($4,003)	($12,136)	($19,817)	($38,867)
19	Average Balance	($4,731)	($12,487)	($20,235)	($40,433)
20					
21	Deferred FIT - 12/31/11	($20,052)	($47,158)	($75,854)	($154,257)
22	Deferred FIT - 12/31/12	($14,704)	($44,574)	($72,789)	($142,759)
23	Average Balance	($17,378)	($45,866)	($74,321)	($148,508)
24					
25	Net Year End Balance	$27,308	$82,780	$135,180	$265,125
26					
27	Amortization begin date (a)	May-03	Aug-03	May-04	Jun-05
28	Amortization period (months)	149	320	389	240
29	Amortization as of 12/31/11	104	101	92	79
30	Amortization as of 12/31/12	116	113	104	91

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Preferred Stock Jan-07	(4) Tax Exempt Bonds Mar-08	(5) Tax Exempt Bonds Mar-08	(6) Tax Exempt Bonds Mar-08
	Total Company	$740,468	$439,979	$668,515	$790,973
1	Gas Amount Refinanced	$118,475	$70,397	$106,962	$126,556
2	Deferred SIT	($10,307)	($6,125)	($9,306)	($11,010)
3	Deferred FIT	($37,859)	($22,495)	($34,180)	($40,441)
4					
5	**Earnings**				
6	Amortization	$11,847	$3,140	$4,411	$4,149
7	DSIT	($1,031)	($273)	($384)	($361)
8	DFIT	($3,786)	($1,004)	($1,409)	($1,326)
9	Total Expense	$7,031	$1,864	$2,618	$2,462
10	Earnings	($7,031)	($1,864)	($2,618)	($2,462)
11					
12	**Rate Base**				
13	Amortizable Balance - 12/31/11	$59,237	$58,359	$90,054	$110,650
14	Amortizable Balance - 12/31/12	$47,390	$55,218	$85,643	$106,500
15	Average Balance	$53,314	$56,788	$87,849	$108,575
16					
17	Deferred SIT - 12/31/11	($5,154)	($5,077)	($7,835)	($9,627)
18	Deferred SIT - 12/31/12	($4,123)	($4,804)	($7,451)	($9,266)
19	Average Balance	($4,638)	($4,941)	($7,643)	($9,446)
20					
21	Deferred FIT - 12/31/11	($18,929)	($18,648)	($28,777)	($35,358)
22	Deferred FIT - 12/31/12	($15,143)	($17,645)	($27,367)	($34,032)
23	Average Balance	($17,036)	($18,147)	($28,072)	($34,695)
24					
25	Net Year End Balance	$28,124	$32,769	$50,825	$63,203
26					
27	Amortization begin date (a)	Jan-07	Mar-08	Mar-08	Mar-08
28	Amortization period (months)	120	269	291	366
29	Amortization as of 12/31/11	60	46	46	46
30	Amortization as of 12/31/12	72	58	58	58

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Tax Exempt Bonds Apr-08	(4) Tax Exempt Bonds Apr-08	(5) Tax Exempt Bonds Nov-08	(6) Tax Exempt Bonds Dec-10
	Total Company	$176,784	$655,565	$84,228	$148,731
1	Gas Amount Refinanced	$28,285	$104,890	$13,476	$23,797
2	Deferred SIT	($2,461)	($9,125)	($1,172)	($2,070)
3	Deferred FIT	($9,039)	($33,518)	($4,306)	($7,604)
4					
5	**Earnings**				
6	Amortization	$1,267	$4,528	$2,344	$1,632
7	DSIT	($110)	($394)	($204)	($142)
8	DFIT	($405)	($1,447)	($749)	($521)
9	Total Expense	$752	$2,687	$1,391	$968
10	Earnings	($752)	($2,687)	($1,391)	($968)
11					
12	**Rate Base**				
13	Amortizable Balance - 12/31/11	$23,536	$87,912	$6,055	$0
14	Amortizable Balance - 12/31/12	$22,270	$83,384	$3,711	$20,397
15	Average Balance	$22,903	$85,648	$4,883	$10,199
16					
17	Deferred SIT - 12/31/11	($2,048)	($7,648)	($527)	$0
18	Deferred SIT - 12/31/12	($1,937)	($7,254)	($323)	($1,775)
19	Average Balance	($1,993)	($7,451)	($425)	($887)
20					
21	Deferred FIT - 12/31/11	($7,521)	($28,092)	($1,935)	$0
22	Deferred FIT - 12/31/12	($7,116)	($26,645)	($1,186)	($6,518)
23	Average Balance	($7,319)	($27,369)	($1,560)	($3,259)
24					
25	Net Year End Balance	$13,216	$49,484	$2,202	$12,105
26					
27	Amortization begin date (a)	Apr-08	Apr-08	Nov-08	Dec-10
28	Amortization period (months)	268	278	69	175
29	Amortization as of 12/31/11	45	45	38	13
30	Amortization as of 12/31/12	57	57	50	25

(a) rounded to nearest full month

Delmarva Power & Light Company
Amortization of Actual Loss/Gain on Refinancing
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Tax Exempt Bonds Dec-10	(4) Tax Exempt Bonds Jun-11	(5) Tax Exempt Bonds Aug-12	(6) Total
	Total Company	$171,299	$634,231	$548,903	$33,107,672
1	Gas Amount Refinanced	$27,408	$101,477	$93,698	$4,034,036
2	Deferred SIT	($2,384)	($8,829)	($8,152)	($350,961)
3	Deferred FIT	($8,758)	($32,427)	($29,941)	($1,289,076)
4					
5	**Earnings**				
6	Amortization	$1,559	$6,803	$6,006	$215,903
7	DSIT	($136)	($592)	($523)	($18,784)
8	DFIT	($498)	($2,174)	($1,919)	($68,992)
9	Total Expense	$925	$4,037	$3,564	$128,128
10	Earnings	($925)	($4,037)	($3,564)	($128,128)
11					
12	**Rate Base**				
13	Amortizable Balance - 12/31/11	$0	$0	$0	$2,095,980
14	Amortizable Balance - 12/31/12	$24,160	$90,706	$87,691	$2,119,032
15	Average Balance	$12,080	$45,353	$43,846	$2,107,506
16					
17	Deferred SIT - 12/31/11	$0	$0	$0	($182,350)
18	Deferred SIT - 12/31/12	($2,102)	($7,891)	($7,629)	($184,356)
19	Average Balance	($1,051)	($3,946)	($3,815)	($183,353)
20					
21	Deferred FIT - 12/31/11	$0	$0	$0	($669,771)
22	Deferred FIT - 12/31/12	($7,720)	($28,985)	($28,022)	($677,137)
23	Average Balance	($3,860)	($14,493)	($14,011)	($673,454)
24					
25	Net Year End Balance	$14,338	$53,829	$52,041	$1,257,540
26					
27	Amortization begin date (a)	Dec-10	Jun-11	Aug-12	
28	Amortization period (months)	211	179	78	
29	Amortization as of 12/31/11	13	7	0	
30	Amortization as of 12/31/12	25	19	5	

(a) rounded to nearest full month

Delmarva Power & Light Company
Cash Working Capital - Interest Synchronization - Gas
12+0 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Revenue	(4) O & M	(5) Depr/Amort	(6) Other Taxes	(7) SIT	(8) FIT	(9) Def Tax/ITC/AFC	(10) Total Expenses	(11) Interest	(12) Earnings
1	Remove Employee Association	$0	($31,452)	$0	$0	$2,736	$10,050	$0	($18,665)		$18,665
2	Regulatory Commission Exp Normalization	$0	$241,180	$0	$0	($20,983)	($77,069)	$0	$143,128		($143,128)
3	Wage and FICA Expense Adjustment	$0	$633,423	$0	$34,551	($58,114)	($213,451)	$0	$396,409		($396,409)
4	Removal of Executive Incentive Compensation	$0	($843,110)	$0	$0	$73,351	$269,416	$0	($500,344)		$500,344
5	Remove Certain Executive Compensation	$0	($14,918)	$0	$0	$1,298	$4,767	$0	($8,853)		$8,853
6	Uncollectible Expense Normalization	$0	$301,917	$0	$0	($26,267)	($96,477)	$0	$179,172		($179,172)
7	Injuries and Damages Exp Normalization	$0	($16,206)	$0	$0	$1,410	$5,179	$0	($9,618)		$9,618
8	Benefits Expense Adjustment	$0	$310,059	$0	$0	($26,975)	($99,079)	$0	$184,004		($184,004)
9	Reflect actual reliability closings January 2013 - June 2013	$0	$0	$152,893	$0	($13,302)	($48,857)	$0	$90,735		($90,735)
10	Reflect forecasted reliability closings July 2013 - December 2013	$0	$0	$206,850	$0	($17,996)	($66,099)	$0	$122,755		($122,755)
11	Remove Bloom-Related Incremental Rate Base	$0	$0	($2,261)	$0	$197	$722	$0	($1,342)		$1,342
12	Reflect Gas AMI Net Plant Additions	$0	$0	$700,266	$0	($60,923)	($223,770)	$0	$415,573	$17,300	($398,272)
13	Remove Meter Reading Expense Silver Spring Network Credit	$0	$0	$0	$0	$0	$0	$0	$0		$0
14	Amortization of Refinancings	$0	$0	$215,903	$0	$0	$0	($87,775)	$128,128		($128,128)
15	Remove Post 1980 ITC Amortization	$0	$0	$0	$0	$0	$0	$50,470	$50,470		($50,470)
16	Recover Credit Facilities Expense	$0	$118,094	$0	$0	($10,274)	($37,737)	$0	$70,083		($70,083)
17	Reflect Taxes Related to Medicare Part D Subsidy	$0	$0	$11,907	$0	($1,036)	($3,805)	$0	$7,066		($7,066)
18	Annualization of Depreciation on Year-end Plant	$0	$0	$382,802	$0	($33,304)	($122,324)	$0	$227,174		($227,174)
19	Total	$0 $0	$698,986	$1,668,361	$34,551	($190,182)	($698,535)	($37,306)	$1,475,876	$17,300	($1,458,576)
20									Int Exp		
21	Rate		0.0729	0.0000	0.1402	0.2206	0.0116		(0.0741)	(0.32685)	
22	Working Capital		$50,963	$0	$4,844	($41,945)	($8,131)		($70,393)	($5,655)	($70,316)
23											
24	Interest Synch 1					($272,784)	($1,001,934)				
25	Working Capital		$50,963	$0	$4,844	($60,163)	($11,663)		($70,263)	($5,655)	($91,936)
26											
27	Interest Synch 2					($272,632)	($1,001,375)				
28	Working Capital		$50,963	$0	$4,844	($60,129)	($11,656)		($70,223)	($5,655)	($91,856)
29											
30	Interest Synch 3					($272,585)	($1,001,203)				
31	Working Capital		$50,963	$0	$4,844	($60,119)	($11,654)		($70,223)	($5,655)	($91,844)
32											
33											
34		Interest Synchronization				Rate Base			Earnings		
35	Per Books Interest	$5,949,867	$5,949,867	$5,949,867	$5,949,867	Per Books Rate Base for COS		$251,434,682	Earning Adjustment w/o Int synch		($1,458,576)
36	Adjusted Rate Base	$276,921,622 (1)	$276,851,306	$276,829,686	$276,829,766	Regulatory Commission Exp Norm.		$250,278	Per Books Earnings for COS		$14,778,975
37	Wtd COD - Proforma Cap Str	0.0249	0.0249	0.0249	0.0249	Reliability Plant Closings Jan 13 - Jun 13		$9,102,819	Sub-Total Earnings		$13,320,399
38	Proforma Interest	$6,895,348	$6,893,598	$6,893,059	$6,893,061	Reliability Plant Closings Jul 13 - Dec 13		$9,216,718			
39	IOCD	$3,977	$3,977	$3,977	$3,977	Remove Bloom Incremental Rate Base		($384,676)	Interest Synchronization		$385,073
40	Total Proforma Interest	$6,899,326	$6,897,575	$6,897,037	$6,897,039	Reflect Gas AMI Net Plant Additions		$6,075,099	Adjusted Earnings		$13,705,471
41	Difference	$949,459	$947,708	$947,169	$947,171	Refinancings		$1,257,540			
42	SIT @ 8.7 %	($82,603)	($82,451)	($82,404)	($82,404)	Recover Credit Facilities Expense		$182,203			
43	FIT @ 35 %	($303,400)	($302,840)	($302,668)	($302,669)	Reflect Taxes Related to Medicare Part D		$14,133			
44						Annualization of Deprec. on Year-end Plant		($227,174)			
45	Earnings	$386,002	$385,291	$385,072	$385,073	Sub-total		$276,921,622			
46						CWC Adjustment		($91,844)			

Schedule (JCZ-R)-11

DELMARVA POWER & LIGHT COMPANY
GAS RATE BASE & REVENUES
12 MONTHS ENDING DECEMBER YEAR-END
($000)

LINE NO.	DESCRIPTION	2008	2009	2010	2011	2012	5 YR. AVERAGE
	RATE BASE						
1	PLANT IN SERVICE	403,604	416,331	430,102	451,482	480,539	
2	DEPRECIATION RESERVE	166,627	173,491	181,818	192,202	200,633	
3	NET PLANT	236,978	242,841	248,284	259,280	279,906	
4							
5	CWIP	3,864	3,725	11,714	14,563	10,231	
6	GAS FUEL INVENTORY	30,210	19,076	16,514	16,037	13,471	
7	PLANT MATERIALS AND SUPPLIES	892	758	822	816	948	
8	MISC RATE BASE ITEMS	7,874	3,973	10,513	10,229	17,642	
9	CASH WORKING CAPITAL	10,450	8,436	12,004	13,120	12,499	
10	DEFERRED FIT	(44,311)	(47,246)	(56,650)	(66,210)	(64,279)	
11	DEFERRED SIT	(12,333)	(12,540)	(14,816)	(13,250)	(14,126)	
12	ITC	(716)	(659)	(602)	(546)	(489)	
13	CUSTOMER ADVANCES	(219)	(219)	(14)	(14)	(1)	
14	CUSTOMER DEPOSITS	(4,082)	(3,799)	(3,990)	(3,927)	(3,342)	
15							
16	NET RATE BASE	228,608	214,346	223,778	230,098	252,460	
17							
18							
19	REVENUES						
20	DISTRIBUTION REVENUES	68,016	70,107	69,116	71,150	72,066	
21							
22							
23	ANNUAL INCREASE/DECREASE %						
24	NET PLANT	6.92%	2.47%	2.24%	4.43%	7.96%	4.80%
25							
26	NET RATE BASE	-1.36%	-6.24%	4.40%	2.82%	9.72%	1.87%
27							
28	DISTRIBUTION REVENUES	2.27%	3.07%	-1.41%	2.94%	1.29%	1.63%

Delmarva Power & Light Company
Expense Ratio

Schedule (JCZ-R)-12

DE 12-546 PSC-RR-28 Attachment
Updated for 2012 Account 902-Related Adjustment

Source: FERC Form 1 page 354 - 355

(1) Line No.	(2)	(3) 2012	(4) 2011	(5) 2010	(6) 2009	(7) 2008	(8) 2007	(9) 5 Year Average
1	**Total Payroll**	**90,170,669**	**84,700,643**	**79,074,902**	**77,356,255**	**76,614,928**	**74,511,735**	
2								
3	**GAS**							
4	O&M Salaries & Wages Gas	11,178,246	9,350,263	9,866,116	9,502,031	9,493,456	9,318,783	
5								
6	Net Gas O&M	11,178,246	9,350,263	9,866,116	9,502,031	9,493,456	9,318,783	
7								
8	Gas Plant Construction	4,251,416	4,305,528	4,457,273	4,769,355	96,046	5,384,229	
9	Gas Plant Removal	386,493	331,194	318,377	340,668	96,046	12,245	
10	Other Capital (101,181,186)					3,777,828	221,386	
11	Capital amounts in O&M					147,911		
12	Net Gas Capitalized	4,637,909	4,636,722	4,775,650	5,110,023	4,117,831	5,617,860	
13								
14								
15	**ELECTRIC**							
16	O&M Salaries & Wages Electric	36,363,142	39,468,106	34,733,588	31,765,569	32,046,446	31,726,145	
17								
18	Net Electric O&M	36,363,142	39,468,106	34,733,588	31,765,569	32,046,446	31,726,145	
19								
20								
21	Electric Plant Construction	27,440,962	25,170,776	24,833,377	26,231,453	9,892,785	23,393,121	
22	Electric Plant Removal	6,570,372	3,311,945	2,228,637	2,725,345	576,279	406,211	
23	Other Capital (101,181,186)					16,519,990	1,760,917	
24	Capital amounts in O&M					908,599		
25	Net Electric Capitalized	34,011,334	28,482,721	27,062,014	28,956,798	27,897,653	25,560,249	
26								
27								
28	**NON-UTILITY/OTHER**							
29	Salaries charged expenses	3,980,038	2,762,831	2,637,534	2,021,834	3,059,542	2,288,698	
30								
31	Net Non-Utility/Other	3,980,038	2,762,831	2,637,534	2,021,834	3,059,542	2,288,698	
32								
33								
34	Total Payroll Charged	90,170,669	84,700,643	79,074,902	77,356,255	76,614,928	74,511,735	
35								
36	Gas O&M and Capital %							
37	Net Gas O&M	11,178,246	9,350,263	9,866,116	9,502,031	9,493,456	9,318,783	
38	Net Gas Capitalized	4,637,909	4,636,722	4,775,650	5,110,023	4,117,831	5,617,860	
39	Net Gas Total	15,816,155	13,986,985	14,641,766	14,612,054	13,611,287	14,936,643	
40								
41	O&M %	70.68%	66.85%	67.38%	65.03%	69.75%	62.39%	67.01%
42	Capital %	29.32%	33.15%	32.62%	34.97%	30.25%	37.61%	32.99%
43								
44								
45	2012 vs. 2011 Accounting Change Variance							
46	Account 902 Salaries	1,235,496						
47								
48	Net Gas O&M	9,942,750	9,350,263	9,866,116	9,502,031	9,493,456	9,318,783	
49	Net Gas Capitalized	4,637,909	4,636,722	4,775,650	5,110,023	4,117,831	5,617,860	
50	Net Gas Total	14,580,659	13,986,985	14,641,766	14,612,054	13,611,287	14,936,643	
51								
52	O&M %	68.19%	66.85%	67.38%	65.03%	69.75%	62.39%	66.60%
53	Capital %	31.81%	33.15%	32.62%	34.97%	30.25%	37.61%	33.40%

Schedule (JCZ-R)-13

Delmarva Power & Light Company
Docket No. 12-546
Example of NOL Impact on Deferred Tax Balance

(1) Line No.	(2) Item	(3) Scenerio 1 With Taxable Income		(4) Scenerio 2 Without Taxable Income	
1	**Revenues**	$ 1,000		$ 1,000	
2					
3	**Expense**				
4	Book depreciation	$ 250 a)		$ 250 a)	
5					
6	Current Tax Expense	$ 200 c)		$ - c)	
7	Deferred Tax Expense	$ 100 d)		$ 300 d)	
8					
9	Total expense	$ 550		$ 550	
10					
11	Earnings	$ 450		$ 450	
12					
13					
14	**Rate Base**				
15	Deferred Tax Balance	$ 100 d)		$ 900 d)	
16	NOL Deferred tax			$ (600)	
17	Net Rate Base	$ (100)		$ (300)	
18					
19					
20	a) Plant asset	$ 5,000		$ 5,000	
21	book depreciation rate	5%		5%	
22	Book Depreciation expense	250		250	
23					
24	b) Plant asset	$ 5,000		$ 5,000	
25	tax depreciation rate	10%		50%	
26	tax depreciation	$ 500		$ 2,500	
27					
28					
29	EBIT	$ 750	line 1 - line 4	$ 750	line 1 - line 4
30	<u>Tax Calculation</u>				
31	add back book depreciation exp	$ 250 a)		$ 250 a)	
32	subtract tax depreciation exp	$ (500) b)		$ (2,500) b)	
33	Taxable Income pre carry-forward	$ 500		$ (1,500)	
34	NOLC	$ -		$ (1,500)	
35	Taxable Income	$ 500		$ -	
36					
37	Current Tax	$ 200	line 35 * 40%	$ -	line 35 * 40%
38	Deferred Tax	$ 100	(line 32 - line 31) * 40%	$ 900	(line 32 - line 31) * 40%
39	NOL Deferred Tax	$ -	line 34 * 40%	$ (600)	line 34 * 40%
40	Total Tax	$ 300 40%		$ 300 40%	
41					
42					
43	Note: for illustrative purposes assumes a 40% composite tax rate, a 5% book depreciation rate and the same tax depreciation rate for both state and federal returns				

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMMISSION
REBUTTAL TESTIMONY OF ROBERT M. COLLACCHI
DOCKET NO. 12-546

Q1. Please state your name and position.

A1. My name is Robert M. Collacchi and I am Director of Gas Operations & Engineering. I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What is the purpose of your Rebuttal Testimony?

A2. The purpose of my testimony is to address the recommendations of various witnesses that seek to disallow rate base treatment for much needed investment that is designed to continue Delmarva's efforts to provide safe and reliable service to its Delaware customers. I will provide an update on the IMU Deployment and activation in Delaware. I also will address issues raised in the direct testimonies of PSC Witness Michael J. McGarry Sr. and DPA Witness Glenn A. Watkins with regard to main extension issues.

Q3. DPA Witness Watkins and Staff Witness Peterson both oppose the recovery of post-test year reliability plant adjustments in this proceeding. Do you have any comment?

A3. Yes. The Company's application seeks recovery for the costs of investments in its natural gas distribution system that are necessary to ensure safe and reliable service for all of its customers. The reliability plant additions that are included in the Company's adjustments discussed in Company Witness Ziminsky's testimony are not designed to serve new load nor will they generate new revenue for the Company. In fact, no party to this proceeding has offered any testimony that questions whether or not the Company should be making the investments that it has to ensure reliability and replace aging infrastructure.

The General Data Request PSC-GEN-4 asked the Company to "Provide any DOT assessments or filings that identify projects determined to be "critical need." There were several letters in the data request regarding the impact of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. There is a letter from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to the Delaware Public Service Commission (PSC) that urged State public utility commissions to accelerate the repair, rehabilitation, and replacement of high-risk pipeline infrastructure. In the August 7, 2012 response, the Delaware PSC Chair acknowledged "Over the past ten years, Delmarva Power has eliminated 28% of the cast iron from its system, replacing eight miles in 2011 alone. Delmarva Power has invested an average of $10 million per year as part of its rehabilitation and replacement program and it projects that all of its cast iron will be rehabilitated or eliminated within the next twenty years. Under its rehabilitation and replacement program, Delmarva Power works closely with other utility companies, municipalities, and state highway officials to coordinate its work with road or other excavation activities, and it promptly responds to lines that are analyzed to be obsolete based on leakage analysis and other continuous surveillance activities."

In addition to cast iron and steel gas mains, the Company has reliability and replacement programs for certain plastic gas mains, metallic service lines, regulator stations, and necessary upgrades for gas storage facilities. These are on-going projects that often provide immediate benefits to customers and the general public. To complete the rehabilitation and replacement program recognized by the Delaware PSC will require continued investments.

AMI

Q4. DPA Witness Watkins at page 17 of his Direct Testimony cites to your Direct Testimony regarding the number of installed and activated/operational meters as support for his recommendation for "no rate recognition of the Company's AMI plant in service" for purposes of this rate case. Could you please provide an update on the IMU deployment and activation?

A4. The total number of gas meters at customer premises is 130,324. Approximately 90% (117,272) of gas IMU's have been installed on these meters as of June 26, 2013, of which 66% (77,960) have been optimized and activated for over the air meter reading. The remaining 13,052 gas meters without an IMU includes 1,619 large meter sizes for which Silver Spring Network and the gas meter manufacturer are expected to deliver an AMI solution by first quarter 2014. The remaining 11,433 small meters without an IMU are planned to be equipped with an IMU by the end of the fourth quarter 2013.

Q5. Do you concur with DPA Witness Watkins' recommendation that there should be no rate recognition of these costs until the program is fully operational and savings are realized by ratepayers?

A5. No, I do not. The majority of the IMU's will be deployed, activated and providing service to customers before this case concludes; therefore the Company seeks rate recognition of these costs.

Q6. Do you agree with Staff Witness Cohen's proposal for recovery of the AMI regulatory asset associated with the deployment of the Gas IMUs?

A6. Not entirely. The Company's modified proposal is that upon the deployment and activation of at least 95% of IMU's at customer premises, the Company will make a filing six months later for recovery of the initial phase-in amount related to aggregate AMI regulatory balance as discussed by Witness Ziminsky.

Main Extension

Q7. DPA Witness Watkins cites to what he characterizes as a similar main extension approach proposed by Chesapeake Utilities Corporation (Chesapeake) in Docket No. 12-292 as part of his recommendation to conduct workshops concerning the Company's proposal. Do you agree with this recommendation?

A7. Not entirely. Working group meetings are not necessary to address the issues raised by the Company's proposal; however, if the Commission feels strongly that such a process should be followed we will not oppose it. The Company does not believe that working group meetings are necessary because the issues have been thoroughly discussed by the affected parties. First, the Company's proposal takes what has been in existence in Chesapeake's tariff since at least September 2, 2008, and makes a slight modification to it in order address some of the differences that exist in the Company's service territory. In addition, during the Chesapeake working group meetings in which changes to their tariff provisions pertaining to service extension were discussed, some who attended questioned why the Chesapeake proposal had not been part of a base rate case. With the opportunities for discovery and a full examination of the issues raised, a working group is not necessary at this time. Contrary to DPA Witness Watkins' characterization, the Company's proposal does contain differences from that offered by Chesapeake and does not raise the same issues that justified convening a working group there. As Intervenor Caesar Rodney Institute (CRI) has noted, the separate strategies of Chesapeake and Delmarva "sets up a perfect one to one comparison of strategies so we can compare future results." (Direct Testimony of David Stevenson, Lines 84-85)

To convene a working group would only serve to unnecessarily delay the implementation of a program that serves to meet the objective of making natural gas available to all Delawareans.

Q8. Why is Delmarva proposing a different main extension approach than that offered by Chesapeake?

A8. The Company's proposal is mainly in response to requests from our customers to make natural gas available to their subdivisions. Delmarva initially sought to request the same 100 feet per customer as exists in the current (pre-working group) Chesapeake tariff (Third Revised Sheet No. 12). Delmarva then intervened in Chesapeake Docket No. 12-292 to maintain awareness of Chesapeake's new tariff proposal. During the workshops it became apparent that Chesapeake's proposed tariff changes were ideally suited to Chesapeake's rural infrastructure. For Delmarva's reticulated (looped and integrated) infrastructure, 100 feet of main per customer is reasonable and provides efficiencies. As Staff Witness McGarry notes that "individual company demographics, circumstances, and costs should be evaluated in their own context and decisions made based on the particular situation." (Direct Testimony of Michael J. McGarry, Page 12, Lines 14-16).

The rural composition of Chesapeake's service territory in Kent and Sussex counties frequently requires that long approach mains must be installed before reaching the first customer. In contrast, Delmarva's service territory features an existing and already significantly developed infrastructure. As a result, the length of new required approach mains is significantly less in Delmarva's service territory.

A majority of the Delmarva service territory is highly reticulated providing the opportunity for growth with much less approach main than would typically be required in Chesapeake's territory to the south. Expanding this reticulation affords additional pipe looping which further strengthens the system, allowing for more growth on already existing approach mains. Not all service territories would be suitable for Delmarva's proposed main expansion initiative, but for Delmarva it provides a unique opportunity. Delmarva and its customers benefit from the urban and suburban build out of New Castle County that has preceded this main extension tariff change request.

Q9. Following the reasoning presented above, can you provide an example of current housing developments in Delmarva's service territory that have expressed an interest the main extension policy as proposed by the Company?

A9. Several residential subdivisions, including Hillstream II, Edenridge, and Chestnut Hill Estates, have met with or contacted Delmarva recently expressing their interest in the main extension proposal. For each of these three subdivisions there are existing gas mains on one-third to one-half of the homes. Therefore, little to no approach main would need to be constructed in order to connect the first homes. Hillstream II notes that "(There is...) value of natural gas service to a Delaware resident. Not only does natural gas provide an economic alternative to other fuels, but it is much better for our environment. However, this pales in comparison to the impact on marketability of a residence with natural gas versus one without this service. Property owners of all types without natural gas are at a significant disadvantage to similarly situated properties. The depressing effect on sales and pricing must have a measurable impact on the Delaware economy."[1]

Q10. Does the existing main extension policy result in new customers subsidizing future customers?

A10. At times, it does. Under the current tariff structure, a new customer pays the whole cost of getting gas service to their home. CRI notes that "with the current tariff structure a new customer pays the whole cost to get to their home and the next customers along the way get their service for free. That is the real unfair subsidy." (Direct Testimony of David Stevenson, Lines 70-72). The existing main extension policy creates a free-rider problem that exists when the initial customer who requests the extension bears the full cost of the extension. As a result, the existing policy acts as an impediment to promoting the increased use of natural gas as customers may be reluctant to be the first in line for an extension. Delmarva's proposed main extension policy attempts to bring the economic and societal benefits to the general public while spreading any costs greater than 100 feet per home across a wider customer base.

Q11. Does the Company expect that the new main extension policy will result in more than one customer being served by a 100 foot main extension?

A11. In many cases, yes. When installing main in existing residential subdivisions it is typical that a single main be installed on any given street. It is also typical that

[1] See Kim Robert Scovill email to Attorney General 6/9/2013 08:08AM attached as Schedule (RMC-R)-1.

the street has homes along each side of the newly installed gas main. Therefore 100 feet of main is in place to serve at least two customers. But in certain circumstances even more customers are served. For example, in single family residential subdivisions with property frontage less than 100 feet, three to four customers can be served through a single 100 foot main extension. In townhome developments, still more customers are reached. Therefore economic and societal benefits are often brought within reach of several customers through a single 100 foot main extension.

Witness McGarry presents an example of 25 homes requiring exactly 2500 feet of main. This example must also be compared with the reality of the existing single family homes in Chestnut Hill Estates which have less than 100 foot of frontage and homes on both sides of the road. That same 2500 feet of main allows up to 75 single family homes in Chestnut Hill Estates to convert to natural gas service, and that same 2500 feet of main has the potential to reach 200 townhomes.

Such opportunities are recognized and supported by the other parties to this proceeding. For example, CRI notes that "fuel switching is encouraged by Delaware Code and is a specific goal of DNREC." (Direct Testimony of David Stevenson, Lines 42-43). Witness Watkins at page 39 of his Direct Testimony supports the objective of making natural gas available to more Delawareans. He notes, however, that due to "timing" issues "conversion may be delayed and that "little revenue will be generated to offset the investment costs." (Direct Testimony of Glen Watkins, Page 41 Lines 19-21). The fact that two, three, or more residences per 100 foot of main extension will have access to natural gas mitigates the "timing" concerns raised by Witness Watkins. In fact, making natural gas service available to two, three or more residences will put Delmarva in a better position to receive revenue from more than one customer for each 100 foot main extension.

Q12. Do you have any additional comments due to the timing concerns raised by DPA Witness Watkins?

A12. Witness Watkins at page 39 of his testimony states that even if natural gas service is available to more customers "a high percentage of residences are not likely to convert to natural gas for at least several years." He reasons that customers will not convert their heating sources until the time that replacement is necessary. Witness Watkins, therefore raises two distinct yet interrelated "timing" issues. First is the timing of the replacement of the resident's home heating system. Second is the timing of the main installations. While Witness Watkins claims that there may be delay in customer switching, the more important point is that if mains are not installed in advance of the "residents need to replace their heaters," the proportion of the public policy benefits realized is reduced substantially.

In his State of the State address (January 17, 2013) Governor Markell noted that "we need to expand natural gas infrastructure across our state. Too many in Delaware are paying too much for energy because they are too far from a pipeline to bring them affordable natural gas. The energy savings from fuel switching are substantial and can cover the costs of new infrastructure. To help businesses and residents save money, we are working with both Delmarva and Chesapeake to make it easier for businesses to switch to cheaper and cleaner energy." Witness McGarry agrees, noting that "allowing the Company to implement these changes will be consistent with the State's desire to allow flexibility with respect to choice of energy providers, reduce the dependence on foreign oil, and provide end users who would otherwise not have a choice of the type of energy with the opportunity to lower their energy costs in using natural gas." (Direct Testimony of Michael McGarry, Page 3 Lines 18-22).

Realistically, the benefits stated by Governor Markell and Witness McGarry in the above paragraph cannot be realized if the potential natural gas user does not already have a gas main in front of their home. While Witness Watkins notes that "there is a strong tendency for residences to not convert their existing heating sources until such time as replacement is necessary" the fact remains that the realization of economic and societal benefits of the main extension proposal will be enhanced if the pipe is in place before the residents are faced with the critical decision and expense of replacing their fuel consuming domestic appliances.

Conversion of an entire residential subdivision, as the Company's policy is designed to promote, permits higher level coordination than a piecemeal approach. Residents of Delaware will experience less inconvenience under this aggregated approach because, for example, construction necessitated road interruptions will be greatly minimized. In addition, by allowing the civic association to act on behalf of the residents there is a single point of contact and Delmarva's internal processes become seamless to the average customer, who at the end of the process will have a gas line in-place when they are ready to convert.

Q13. What is your opinion about the requirement for a surety bond or some similar financial instrument in connection with the 100 foot extension as suggested in Witness McGarry's testimony?

A13. Requiring a homeowners association or civic organization to post a surety bond or similar financial instrument for the cost of the 100 foot extension is problematic. Homeowners associations and civic organizations are not always created as legal entities, and, therefore, do not have the ability to secure such instruments. Further, if they are legal entities with the right to borrow and have funds on hand, the amount of those funds are usually small, and not sufficient to provide security or collateral for a surety bond or other financial instrument. It is doubtful that a bonding company or financial institution would be willing to consider these associations/organizations as qualifying for such instruments. In addition, these organizations are staffed by volunteer homeowners who normally do not have the financial sophistication necessary to understand the requirements of such financial instruments.

Q14. Does this conclude your Rebuttal Testimony?

A14. Yes, it does.

RE: Delmarva Gas Rate Case - Opposition of Extension of Natual Gas Service By Attorney General
Iorii, Regina (DOS)
to:
Kim Robert Scovill
06/10/2013 09:46 AM
Cc:
"Adams, James (DOJ)", "Price, Ruth A (DOS)", "Maucher, Andrea (DOS)", Glenn Watkins, "Todd Goodman (todd.goodman@pepcoholdings.com)", "PJScott@pepcoholdings.com", "James McC. Geddes (jamesgeddes@mac.com)", "David Stevenson (davidstevenson1948@gmail.com)", "Kowalko, John (LegHall)"
Hide Details
From: "Iorii, Regina (DOS)" <regina.iorii@state.de.us> Sort List...
To: Kim Robert Scovill <kimrobertscovill@yahoo.com>,
Cc: "Adams, James (DOJ)" <James.Adams@state.de.us>, "Price, Ruth A (DOS)" <ruth.price@state.de.us>, "Maucher, Andrea (DOS)" <andrea.maucher@state.de.us>, Glenn Watkins <watkinsg@tai-econ.com>, "Todd Goodman (todd.goodman@pepcoholdings.com)" <todd.goodman@pepcoholdings.com>, "PJScott@pepcoholdings.com" <PJScott@pepcoholdings.com>, "James McC. Geddes (jamesgeddes@mac.com)" <jamesgeddes@mac.com>, "David Stevenson (davidstevenson1948@gmail.com)" <davidstevenson1948@gmail.com>, "Kowalko, John (LegHall)" <John.Kowalko@state.de.us>
History: This message has been forwarded.

Dear Mr. Scovill:

The AG's witness did not oppose expansion; he simply does not want current customers to be subsidizing that expansion. He has recommended formation of a working group to discuss the options – as was done with Chesapeake Utilities Corporation.

If you intend to submit testimony opposing our position, you will need to ask the Hearing Examiner for leave to do so. The current schedule does not permit such testimony. The only provision for rebuttal is for Delmarva to rebut the direct testimony of the interveners.

Sincerely, Gina

Regina A. Iorii
Deputy Attorney General
Delaware Department of Justice
820 N. French Street, 4th Floor
Wilmington, DE 19801
(302) 577-8159
regina.iorii@state.de.us

From: Kim Robert Scovill [mailto:kimrobertscovill@yahoo.com]
Sent: Monday, June 10, 2013 8:08 AM
To: Iorii, Regina (DOS)
Subject: Delmarva Gas Rate Case - Opposition of Extension of Natual Gas Service By Attorney General

June 9, 2013

Regina A. Iorii
Deputy Attorney General
Delaware Department of Justice
820 N. French Street, 4th Floor
Wilmington, DE 19801
(302) 577-8159
regina.iorii@state.de.us

Dear Gina:

I am a resident of the Hillstream II neighborhood in New Castle County and have intervened as a such in the DPSC Docket 12-546, Delmarva's natural gas rate case, as a voice for the Hillstream II community, and other homeowners who do not have natural gas service.

We read with great interest the testimony of your witness, Glenn Watkins (attached). Mr. Watkins, beginning on page 40 of his testimony, argues <u>against</u> the extension of gas service in Delmarva's service area. As a neighborhood without natural gas, a situation of such economic impact that we felt it necessary to legally intervene in this rate case, we are very disturbed by this position.

As citizens and voters in Delaware, we have dificulty reconciling that the AG has sponsored the <u>only witness</u> in this matter to testify against service expansion. I hope we do not need to convince you of the value of natural gas service to a Delaware resident. Not only does natural gas provide an economic alternative to other fuels, but it is much better for our environment. However, this pails in comparison to the impact on marketability of a residence with natural gas versus one without this service.

Property owners of all types without natural gas are at a significant disadvantage to similarly situated properties. The depressing effect on sales and pricing must have a measurable impact on the Delaware economy - one that the Attorney General apparently does not fully appreciate.

We plan to oppose this point in Mr. Watkin's testimony, and hope to rally others to do the same both in the rate case and directly to the Attoney General.

Sincerely,

Kim

Kim Robert Scovill
1 Radburn Lane
Newark, DE 19711
302-239-2553
kimrobertscovill@yahoo.com

Rebuttal Testimony of
Marlene C. Santacecilla

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMMISSION
REBUTTAL TESTIMONY OF MARLENE C. SANTACECILIA
DOCKET NO. 12-546

Q1. Please state your name and position.

A1. My name is Marlene C. Santacecilia. I am a Regulatory Affairs Lead in the Rate Economics Department of Pepco Holdings Inc. (PHI). I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What is the purpose of your Rebuttal Testimony?

A2. The purpose of my Rebuttal Testimony is to discuss:

1. Delaware Public Service Commission Staff (Staff) Witness Davis' identification of a typo on Tariff Leaf No.81 Rider "UFRC" Utility Facility Relocation Charge Rider (rider UFRC).
2. Staff Witness Peterson's characterizations of the revenue impact.
3. Staff Witness Kalcic rate design modifications and the reasonableness of the proposed $50 unauthorized overrun penalty during Non-Operational Flow Order periods and $60 unauthorized overrun penalty during Operational Flow Order (OFO) periods.
4. Delaware Public Advocate (DPA) Witness Watkins assertions that certain revenue adjustments were incomplete or non-transparent; that certain rate design proposals were not appropriate; and that the main extension policy should be analyzed in a working group.

5. Staff Witness McGarry and DPA Witness Watkins comments regarding the proposed modifications to the Main Extension Policy.
6. The effect of Company Witness Ziminsky's rebuttal testimony support of a reduced revenue requirement on the filed tariffs.

Q3. Do you have any corrections to the Tariffs found in Appendix A of the Application Book?

A3. Staff Witness Davis correctly pointed out a minor error in Leaf No. 81 Rider "UFRC" Utility Facility Relocation Charge Rider. The corrected tariff leaf is attached as Schedule (MCS-R)-1.

Q4. Please address Staff Witness Peterson's claim, on page 4 of his Direct Testimony, that the Company's proposal is *more accurately* (emphasis added) stated as a 17.1 percent increase versus the 7.87 percent increase stated in the application. Page 4.

A4. Neither presentation is more or less accurate. The increase requested here is both a 7.87% increase on a customer's total bill and, as stated in the original filing in Schedule (MCS)-1, a 17.39% increase in delivery revenues. A customer's Delmarva bill contains more than a simple delivery charge. Delivery charges are less than 50% of an average customer's total bill.

Q5. Please comment on Staff Witness Kalcic's Direct Testimony regarding the Company's rate design.

A5. While Staff Witness Kalcic, on page 13 of his Direct testimony, accepts the Company's filed rate structure recommendation, including the addition of a demand charge for the LVG-QFCP service classification, the allocation of the revenue increase offered varies slightly. In my Direct Testimony, I used a two-part dead band formulation which produces both increases and decreases for the various service classifications. This is in an effort to move every service classification closer to the overall rate of return. Staff Witness Kalcic chooses to maintain the rate of return for rate classes that are earning more than the allowed rate of return so that there are no service classes receiving a decrease. This serves to further perpetuate "subsidization" by those service classifications of service classifications that are earning below the allowed rate of return but does share the burden of the increase across all the service classifications.

Q6. Please discuss the Company's proposal to increase its unauthorized overrun penalty to $50 during non-Operational Flow Order periods and $60 during Operational Flow Order (OFO) periods.

A6. At this time the Company agrees with Staff Witness Kalcic's recommendation to increase the unauthorized overrun penalty to $50 regardless of system conditions including during OFO situations.

Q7. Do you agree with DPA Witness Watkins' statement that there is additional revenue that should be included in the Year-end Customer Revenue Adjustment.

A7. At page 6 of his direct testimony, DPA Witness Watkins asserts that Delmarva "erred by not including all revenues that coincide with this [end of test year rate base] valuation." While I agree that the Company adjusted revenues based on customer charge revenues only, the adjustment does not require modification. Much of any change in customer count in the medium and large customer classes can be correctly attributed to customer migration between rate classes as noted by DPA

Witness Watkins. For the Residential and General Gas Service Classifications changes in the number of customers is generally attributable to entrance and exit to the system. The discernible (and quantifiable) effect of that migration establishes the difference in customer charge revenues. When changes in customer count are the only known and measurable cause of the difference in customer charge revenues, making a revenue adjustment using only customer charge revenue is reasonable. These new and/or exiting customers are not necessarily average customers, a fact that would have to be established prior to approval of DPA Witness Watkins' average use adjustment. Without knowing who these customers are and what their usage pattern will be, it seems contrary to the known and measurable standard to use average usage.

Q8. Please discuss the reasonableness of Delmarva's weather normalization adjustment.

A8. On October 19, 1994, the Commission accepted a settlement in Delaware Gas Docket No. 94-22 Order No. 3876 which specified weather normalization parameters. Delmarva has been using the same methodology in every gas and electric base case since that time. Additionally, Staff took no issue with the Company's weather normalization adjustment.

Q9. Do you agree with DPA Witness Watkins assertion that "there is no support whatsoever as to how this adjustment was made in either the Minimum Filing Requirements or the Company witnesses' schedules."

A9. No. Schedule (MCS) – 4 shows the weather normalization revenue adjustment by Service Classification and the response to PSC-RR-15 shows how those revenue amounts were calculated. Using the weather correction data provided by the Company's Economic Forecasting team and provided as tab "Sales Weather Adj" in the Attachment to PSC-RR-15, billing determinants were adjusted to reflect the weather correction and then billed out to create the revenue adjustment (see tab "Determinant – Adjustments".) Further, although the methodology for calculating the weather correction data was outlined in my Direct Testimony, DPA did not ask any follow-up data requests that identified a need for more information specifically related to that testimony, Schedule (MCS)-4 or the response provided in PSC-RR-15.

Q10. Please discuss the rate design changes suggested in the Direct Testimony of DPA Witness Watkins.

A10. DPA Witness Watkins makes a few minor modifications to the Company's rate design proposal. Although he agrees with the concept of gradualism, DPA Witness Watkins disagreed with the Company's gradual customer charge increase for the residential class. While the concept of gradualism is somewhat subjective, it should be noted that the approximately 29% increase in customer charge proposed by the Company allows the residential rate to fully reflect the customer cost allocation that the Cost of Service Study (COSS) suggests.

Additionally, DPA Witness Watkins disagrees with the maintenance of the declining block structure traditionally reflected in the residential rate structure. Although the Company does not disagree that the Residential rate structure may warrant redesign, the Company is reluctant to modify the rate structure too dramatically without further study. Using the "as filed" rate design and setting the "declining block" charge at 90% of the first block charge would increase the first block rate by 6% while a Residential Space Heating customer would experience a rate increase of close to 19% in the declining block charge. Due to the fixed nature of the distribution system costs, any rate based on volume might create or exacerbate intra class subsidization. An analysis of the distribution system cost differential, if any, of serving residential and residential space heating customers should be undertaken before considering any rate structure changes. Several area utilities do offer the flat residential distribution rate that DPA Witness Watkins suggests, other providers still maintain rates which offer substantial discounts for usage greater than 50 ccf.

Q11. Please discuss Delmarva's main extension tariff in the context of the Direct Testimony of Staff Witness McGarry and DPA Witness Watkins.

A11. Company Witness Collachi addresses modifications proposed by Staff Witness McGarry and DPA Witness Watkins. The Company maintains its filed position and no substantive changes are necessary to the proposed tariff language.

Q12. Have you adjusted the Company's proposed tariffs to reflect Company Witness Ziminsky's rebuttal revenue requirement?

A12. No. Company Witness Ziminsky's rebuttal testimony supports a reduction in revenue requirement of $.107 million from the Company's original application, testimony and exhibits. Although this reduction would decrease the level of rates, I continue to support a rate structure that reflects the guidelines outlined in my direct testimony. Ultimately, upon Commission approval, revised rate design and compliance tariffs would be filed that incorporate the approved revenue requirement.

Q13. Does this conclude your Rebuttal Testimony?

A13. Yes, it does.

RIDER "UFRC"
UTILITY FACILITY RELOCATION CHARGE RIDER

A. Purpose

The Utility Facility Relocation Charge (UFRC) is intended to allow Delmarva Power to recover the cost of relocation of existing facilities required or necessitated by Department of Transportation or other government agency projects.

B. Applicablity

This Rider is applicable to any Customer served under Service Classifications "RG", "GG", "GL", "MVG", "LVG", "LVG-QFCP", "PM", "GVFT", "MVFT", "LVFT", "SBS", "QFT", "MVIT", "LVIT", "FPS" and "NCR."

The rate is applicable to the portion of the Customer's charges related to the delivery or distribution of gas.

C. Definitions

1. "Eligible Utility Facility Relocations" mean new, used and useful plant or facilities of a gas utility that:

   i. Do not include that portion of any plant or facilities used to increase capacity of or connect to the system to serve new or additional load;

   ii. Are in service; and

   iii. Were not included in the utility's rate base in its most recent general rate case; and which

   iv. Relocate, as required or necessitated by Department of Transportation or other government agency projects without reimbursement, existing Company facilities, including but not limited to, mains, lines and services, whether underground or aerial. For purposes of this section, "existing facilities" and "relocate" include the physical relocation of existing facilities and also include removal, abandonment or retirement of existing facilities and the construction of new facilities in a relocated location.

2. "Pretax return" means the revenues necessary to:

   a. Produce net operating income equal to the Company's weighted cost of capital as established in the most recent general rate proceeding multiplied by the net original cost of eligible utility facility relocations. At any time the Commission by its own motion, or by motion of the Company, Commission staff or the Public Advocate, may determine to revisit and, after hearing without the necessity of a general rate filing reset the UFRC rate to reflect the Company's current cost of capital. The UFRC rate shall be adjusted back to the date of the motion to reflect any change in the cost of capital determined by the Commission through this process;

   b. Provide for the tax deductibility of the debt interest component of the cost of capital; and

   c. Pay state and federal income taxes applicable to such income.

RIDER "UFRC"

UTILITY FACILITY RELOCATION CHARGE RIDER - continued

C. Definitions (continued)

3. "UFRC costs" means depreciation expenses and pretax return associated with eligible utility facility relocations.

4. "UFRC rate" refers to utility facility relocation charge.

5. "UFRC revenues" means revenues produced through a UFRC exclusive of revenues from all other rates and charges.

D. Filing

1. The UFRC rate shall be adjusted semiannually for eligible relocation expenses placed in service during the 6-month period ending 2 months prior to the effective date of changes in the UFRC rate .

2. The effective date of changes in the UFRC rate shall be January 1 and July 1 every year.

3. The Company shall file any request for a change in the UFRC rate and supporting data with the Commission at least 30 days prior to its effective date.

4. The UFRC rate applied between base rate filings shall be capped at 7.5% of the portion of the Customer's charge related to the delivery or distribution of gas, but the UFRC rate increase applied shall not exceed 5% within any 12-month period.

5. The UFRC rate will be subject to annual reconciliation based on a period consisting of the 12 months ending December 31st of each year. The revenue received under the UFRC for the reconciliation period shall be compared to the Company's eligible costs for that period with the difference between revenue received and eligible costs for the period recouped or refunded, as appropriate, over a 1-year period commencing July 1 of each year. If the UFRC revenues exceeded the UFRC eligible costs, such over-collections shall be refunded with interest.

6. The UFRC rate shall be reset to zero as of the effective date of new base rates that provide for the prospective recovery of the annual costs theretofore recovered under the UFRC rate.

RIDER "UFRC"

UTILITY FACILITY RELOCATION CHARGE RIDER – continued

E. Filing (Continued)

7. The UFRC rate shall also be reset to zero if, in any quarter, data filed with the Commission by the Company show that the electric utility will earn a rate of return that exceeds the rate of return established in its last general rate filing or by Commission order as described in paragraph 2.a of this Rider, if such was determined subsequent to the final order in the company's last general rate filing. Further, the UFRC rate shall be reinstated when such data show that the established rate of return is not exceeded and will not be exceeded if the UFRC rate is reinstated and reset.

The UFRC is set forth as follows: 0.00%