Delmarva Power & Light Company

Application for an Increase in Electric Base Rates

Direct Testimony of Boyle, Hevert, Maxwell and Ziminsky
(Book 2 of 3)

Before the Delaware Public Service Commission

March 22, 2013

TESTIMONY OF FREDERICK J. BOYLE

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF FREDERICK J. BOYLE
DOCKET NO. _____

Q1. Please state your name and position.

A1. My name is Frederick J. Boyle. I am Senior Vice President and Chief Financial Officer of Pepco Holdings, Inc. (PHI). I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What are your responsibilities in your role as Senior Vice President and Chief Financial Officer?

A2. I am responsible for all financial matters related to PHI and its three utility subsidiaries, including Delmarva. My responsibilities include: accounting and financial reporting; treasury operations; pension administration; strategic planning; and investor relations.

Q3. Please state your educational background and professional experience.

A3. I hold a Bachelor of Science degree in Business Administration from The Ohio State University and a Master of Tax from Capital University. I am a Certified Public Accountant.

I joined PHI in April 2012 as Senior Vice President and Chief Financial Officer. Prior to joining PHI, I was Senior Vice President and Chief Financial Officer of Dayton Power and Light Company (Dayton), an Ohio-based electric company serving over 500,000 customers in West Central Ohio with a market capitalization of $3.5 billion. At Dayton, I was responsible for all finance, accounting, tax, risk management, treasury, planning, and development activities. Prior to joining Dayton, I served as Vice President of Finance for Direct Energy and as Chief Financial Officer for Accent Energy; both companies are retailers of energy and related services in North America. Prior to these roles, from 1984 to 2002, I served in financial and accounting roles at American Electric Power Service Corporation one of the nation's largest energy companies, serving in leadership roles in the areas of tax, corporate planning, budgeting, and corporate development with the most senior role as Vice President of Financial Services for the corporate development department. I began my career with the accounting firm of Deloitte & Touche.

Q4. What is the purpose of your Direct Testimony?

A4. The purpose of my Direct Testimony is to: (a) provide an overview of the Company's application for an increase in base distribution rates; (b) briefly summarize the testimony of the Company's witnesses; (c) discuss why it is important for Delmarva's customers that the Company have access to capital on reasonable terms and from where that capital comes; (d) discuss Delmarva's proposed capital structure and proposed rate of return; and (e) discuss the economic impacts that the Company provides to the State of Delaware.

This testimony was prepared by me or under my direct supervision and control. The source documents for my testimony are Company records and public documents. I also rely upon my personal knowledge and experience.

Q5. What are the main factors driving this filing?

A5. Delmarva has been investing and plans to continue to invest in its infrastructure to enhance reliability and harden its electric distribution system for its customers. As demonstrated in the Direct Testimony of Company Witness Maxwell, the investment is showing real and measureable results for customers. However, Delmarva is not now earning, and has not for a significant period of time earned, its authorized return on equity. Despite this cycle of under earning, Delmarva has continued its implementation of major reliability enhancements, requiring significant amounts of capital, which address both infrastructure replacement and system enhancements. This case is driven by these on-going investments on behalf of Delmarva's customers and by the fact that, during periods of low customer growth and significant capital investment, the use of historic rate base ensures that the Company will not have an opportunity to earn its authorized rate of return. In addition, the Company has incurred significant costs to respond to recent severe storms, including Hurricane Sandy, which impacted Delaware on October 29, 2012.

Q6. Please describe the Company's application.

A6. This filing consists of the application for an increase in base distribution rates, together with my Direct Testimony and the Direct Testimony of six other witnesses. As described more fully below, those witnesses and the topics they address are as follows:

- Mr. Robert B. Hevert, Managing Partner, Sussex Economic Advisors, LLC, provides testimony and schedules in support of the Company's proposed cost of equity.
- Mr. Michael W. Maxwell, Vice President, Asset Management, provides testimony and schedules on Delmarva's significant investments in reliability.

- Mr. Jay C. Ziminsky, Manager, Revenue Requirements, provides testimony and schedules in support of the Company's revenue requirement, the test year selection, and proposed ratemaking adjustments.
- Ms. Marlene C. Santacecilia, Regulatory Affairs Lead, provides testimony and schedules in support of the proposed rate design and Delmarva's proposed tariffs.
- Ms. Kathleen A. White, Assistant Controller, provides testimony and schedules in support of the Company's accounting books and records and PHI's cost and accounting procedures.
- Mr. Elliott P. Tanos, Manager, Cost Allocation, provides testimony and schedules in support of the Company's cost of service studies.

Q7. Please summarize the Company's rate increase request.

A7. The Company is requesting a $42.044 million increase in base distribution revenue based on a calendar year 2012 test period consisting of twelve months of actual results. The Company is requesting recognition in rate base of reliability and plant additions that will be placed into service through December 31, 2013 to allow Delmarva to recover costs associated with the important reliability and capital investments as those investments are used to provide service to customers.

The request is also based on a rate of return on equity (ROE) of 10.25%. This ROE represents the lower end of the range of returns that Company Witness Hevert found reasonable.

Q8. Why is it necessary for the Company to file for an increase in distribution rates only fifteen months after the Company filed its last case?

A8. The Company filed its prior distribution base rate proceeding, Docket No. 11-528 on December 2, 2011. The Company's test period in that case reflected operating expenses through December 2011. Docket No. 11-528 was concluded through final Commission Order No. 8265, issued on December 18, 2012. In the 15 months that have passed since the filing of that case, and despite the fact that Delmarva is not currently earning its authorized rate of return, Delmarva continues to make significant investments in Delaware's electric system and plans to make infrastructure investments of approximately $397 million in Delaware over the next five years to serve Delmarva's customers. This level of investment, which is required to address infrastructure replacement and to enhance and maintain the reliability of the Company's system, is far in excess of the book depreciation the Company is recovering in rates.

As a consequence, rate base is growing. While significant capital is needed to maintain and upgrade the system, Delmarva is not realizing sufficient growth in the number of customers and load served to offset this pace of investment. Therefore, these investments are being funded on the front end by the Company's debt and equity investors with an expectation that they will receive an opportunity to earn a reasonable return on their investment. Because Delmarva competes with other companies when attempting to raise capital, it is important for Delmarva to be able to demonstrate to its investors that there is a realistic opportunity to earn a rate of return that is commensurate with the rate of return earned by other companies of similar risks. In fact, as Company Witness Ziminsky demonstrates in his Direct Testimony, after annualizing the rates authorized by the Commission in Docket No. 11-528, Delmarva will only earn a 5.59% return on equity during the 2012 test period, which is significantly below the currently authorized ROE of 9.75%.

Q9. What is the potential impact on customers and the Company if Delmarva is unable to receive a reasonable opportunity to earn its authorized rate of return?

A9. Delmarva is concerned that it will not be able to satisfy the needs of its customers, the communities it serves, and its investors if appropriate rate relief is not provided. As discussed in the Direct Testimony of Company Witness Maxwell, Delmarva has demonstrated that it has made, and continues to make, significant enhancements in system reliability. While the Company remains committed to continue those improvements, the ability to do so will become limited and more costly if Delmarva's access to the capital markets on reasonable terms is constrained. No company can continue to function efficiently if forced into an indefinite period of earning returns significantly below market. Such a condition threatens a company's ability to attract capital on reasonable terms, and could also contribute to credit downgrades and other operating constraints which will ultimately result in increased costs to customers.

Q10. What overall rate of return is Delmarva requesting?

A10. As shown in Schedule (FJB)-1, the Company is requesting an overall rate of return (ROR) of 7.53% on its distribution rate base.

Q11. On what capital structure is the overall rate of return based?

A11. The overall ROR is the weighted average cost of capital, based on the Company's December 31, 2012 capital structure ratios of 49.22% common equity and 50.78% long-term debt, its embedded long-term debt cost of 4.91% (see Schedule

(FJB)-1) and its proposed return on common equity of 10.25%, as determined by Company Witness Hevert. This capital structure is consistent with Delmarva's goals and objectives including maintaining its current credit ratings.

Q12. Is this capital structure consistent with industry practice and averages?

A12. Yes. The Company's recommended capital structure is consistent with the 2011 full-year and 2012 year-to-date reported averages of 47.97% and 50.55%, respectively, of the common equity ratios of electric utilities as published in the January 17, 2013 edition of Regulatory Research Associates' "Regulatory Focus: Major Rate Case Decisions."

Q13. Are there other reasons this capital structure is appropriate for use in this proceeding?

A13. Yes. As indicated in the Direct Testimony of Company Witness Hevert, the Company's recommended capital structure is reasonable given a mean common equity ratio of 52.05% and 47.95% long term debt (range between 48.30% and 60.00%) for the 12 companies comprising his peer group for the purpose of determining the cost of equity in this proceeding.

Q14. What are the Company's credit ratings by the major rating agencies?

A14. Delmarva's long-term corporate credit ratings (unsecured debt ratings) are BBB+, Baa2 and A- from Standard & Poor's (S&P), Moody's and Fitch, respectively. As noted in S&P's "Industry Report Card," dated October 22, 2012, 63% of U.S. investor-owned electric utilities carry ratings from BBB- to BBB+, with an additional 35% rated A- or better.

Q15. Please briefly describe the importance of the Company's credit ratings.

A15. As previously stated, the Company's credit ratings indicate the rating agencies' assessment of Delmarva's ability to meet its obligations to its long-term debt holders. The higher the credit rating, the greater the perceived likelihood that debt investors will receive their interest and principal payments as expected. As such, a company with a higher credit rating has access to a larger investor base, faces fewer restrictive covenants and can issue long-term debt at lower cost. This is particularly advantageous today given the Company's plans to invest a significant amount of capital in system reliability, demand response and customer service enhancements, as addressed in the testimonies of Company Witnesses Maxwell and Ziminsky.

Conversely, lower credit ratings reflect increased investor risk. As a result, investors expect to be paid more to provide funds to such an issuer. In addition, lower credit ratings typically result in investors demanding more restrictive terms and covenants from the issuer. Lower credit ratings also limit the pool of investors that may otherwise invest in the Company due to ratings restrictions imposed by some institutional investors. These additional costs associated with lower credit ratings will only increase the costs to Delmarva's customers.

Q16. What is the impact of the requested rate increase on an average residential customer?

A16. The impact of the requested rate increase on a typical residential customer's total monthly bill is $7.63. This equates to $0.25 a day in increased electric rates. The Company acknowledges that any increase can be difficult for customers.

Q17. Does the Company plan to place an interim increase of $2.5 million into effect as permitted under 26. Del. C. § 306 (c)?

A17. Yes. If the Commission chooses to suspend the proposed rate changes for the full suspension period, the Company plans to place in effect, on June 1, 2013, subject to refund, an interim annual increase of approximately $2.5 million. Modified Tariff Leafs reflecting the interim increase are supported by Company Witness Santacecilia and are included in this Application. With the proposed interim base rate increase, on June 1, 2013, a typical residential customer using 1,000 kWh would see a bill increase of $0.53 or 0.38%, from $141.23 to $141.76.

Q18. What economic impact does Delmarva have on the Delaware economy?

A18. As of December 31, 2012, Delmarva provided full-time employment to 1,456 people who work in Delaware and remitted $5.7 million in state and local payroll taxes from their compensation. In addition, Delmarva paid $12.4 million in school and property taxes, which are an important source of public funding for Delaware.

While it would be difficult to tie exact numbers to the following, it is clear that a reliable electric system is critical to the economy. With the advent of the digital age, the economy becomes more dependent every day upon a reliable electric system. When the power is out: communication systems do not operate, computer systems go down, and cash registers do not function. Businesses need a reliable electric distribution system to function successfully. Accordingly, while enhanced system reliability is an important issue for public safety, convenience and quality of life, it is also clear that system reliability is critical to the economy of the state.

Q19. Is Delmarva working with Commission Staff and the Public Advocate on any initiatives arising out of the settlement in Delmarva's last rate case?

A19. Yes. Among the provisions in the settlement in Docket No. 11-528 was an agreement among Commission Staff, the Division of the Public Advocate (DPA) and Delmarva to meet and discuss several issues after that case was concluded. Those issues include: (1) the establishment of a mechanism(s) for reporting on reliability projects going forward; (2) an agreement to meet and discuss alternative regulatory methodologies, including a multi-year rate plan; and (3) continued discussions with Commission Staff on improving financial reporting. Delmarva has been working with Staff and DPA on those issues. It is possible that these meetings could result in proposals that would require Commission review. As discussed in the Application in this filing, to the extent any such proposals are developed and the timing of this docket is such that the proposal(s) could be considered as part of this case, Delmarva will supplement its filing to include any such proposals.

Q20. Please describe the Company's community support initiatives.

A20. Delmarva focuses on providing safe and reliable electric service to its customers. All other customer and community relationships flow from this central principle and provide many opportunities over the course of a year for the Company and its employees to interact with its customers and the communities it serves. Delmarva and The PHI Community Foundation contributed approximately $642,000 to Delaware organizations during the December 31, 2012 test year period. The corporate contributions benefited over 255 organizations to help them meet their goals.

Whether promoting improvements in education, emergency services, health and human services, programs for children and youth, or tackling the issues of hunger and homelessness, Delmarva's giving is meant to help non-profit organizations positively impact community life. These contributions are made by the Company and PHI's shareholders. The contributions are expensed below-the-line and are not funded by Delmarva's customers.

Community involvement is a core value in Delmarva's culture. It is in the best interests of Delmarva's customers and communities that the Company remains financially healthy and continues its efforts as an active member of the community and strong corporate citizen.

Q21. Please summarize your testimony.

A21. Safely serving Delmarva's customers and its communities with reliable electric service is the Company's top priority. There are many challenges ahead to address the realities of necessary infrastructure replacement and electric reliability needs of Delmarva's customers. Meeting those needs involves significant costs and a financially healthy utility is better positioned to navigate through the challenges ahead. This rate request will allow Delmarva the opportunity to earn a reasonable return on equity and to continue to invest in the electric distribution system on behalf of its customers.

Q22. Does this conclude your Direct Testimony?

A22. Yes, it does.

Delmarva Power & Light Company
Overall Rate of Return
December 31, 2012
Delaware

	DPL Delaware		
Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.78%	4.91%	2.49%
Common Equity	49.22%	10.25%	5.04%
Total	100.00%		7.53%

Delmarva Power & Light Company
Capital Structure and Capitalization Ratios
December 31, 2012
Delaware

	Actual	
	December 31, 2012	
Type of Capital	Amount ($)	Ratios
Long-Term Debt	1,023,230,000	
Unamortized Net Discount	(1,749,344)	
Unamortized Debt Issuance Expense	(5,526,574)	
Total Long-Term Debt	1,015,954,082	50.78%
Common Equity	984,604,304	49.22%
Total	2,000,558,387	100.00%

Delmarva Power & Light Company
Weighted Cost of Debt
December 31, 2012
Delaware

Issue	Coupon Rate	Maturity	Offering Date	Current Principal Amount Outstanding	Current Unamortized Debt Issuance Expense	Current Unamortized (Premium)/ Discount	Current Net Amount Outstanding	Effective Cost Rate	Annual Net Cost
First Mortgage Bonds									
	6.40%	12/1/2013	11/25/2008	$250,000,000	$407,477	$108,214	$249,484,309	6.63%	$16,543,935
	4.00%	6/1/2042	6/26/2012	$250,000,000	$2,633,474	$1,365,421	$246,001,105	4.09%	$10,062,249
Total First Mortgage Bonds				$500,000,000	$3,040,952	$1,473,635	$495,485,414		$26,606,183
Unsecured Notes									
	5.00%	11/15/2014	11/19/2004	$100,000,000	$172,095	$91,553	$99,736,351	5.12%	$5,106,276
	5.00%	6/1/2015	6/1/2005	$100,000,000	$209,419	$97,460	$99,693,121	5.11%	$5,094,348
	5.22%	12/30/2016	12/20/2006	$100,000,000	$286,652	$0	$99,713,348	5.30%	$5,282,479
Total Unsecured Notes				$300,000,000	$668,166	$189,013	$299,142,821		$15,483,103
Tax Exempt Fixed Rate Bonds									
	5.40%	2/1/2031	4/1/2010	$78,400,000	$1,299,460	$0	$77,100,540	5.55%	$4,275,718
Total Tax Exempt Fixed Rate Bonds				$78,400,000	$1,299,460	$0	$77,100,540		$4,275,718
Tax-Exempt Variable Rate Bonds									
	0.32%	10/1/2017	10/1/1987	$8,000,000	$49,743	$0	$7,950,257	0.46%	$36,638
	0.32%	10/1/2017	9/28/1988	$18,000,000	$44,479	$0	$17,955,521	0.37%	$67,269
	0.39%	10/1/2028	10/14/1993	$15,500,000	$129,756	$0	$15,370,244	0.45%	$68,399
	0.32%	10/1/2029	10/12/1994	$30,000,000	$180,247	$0	$29,819,753	0.36%	$108,780
	0.43%	7/1/2024	7/28/1999	$22,330,000	$92,045	$0	$22,237,955	0.56%	$124,334
	0.50%	7/1/2024	7/28/1999	$11,000,000	$0	$0	$11,000,000	0.59%	$64,500
Total Tax Exempt Variable Rate Bonds				$104,830,000	$496,269	$0	$104,333,731		$469,920
Medium-Term Notes Series C									
	7.58%	2/1/2017	2/10/1997	$2,000,000	$2,699	$0	$1,997,301	7.65%	$152,864
	7.56%	2/1/2017	2/18/1997	$12,000,000	$16,195	$0	$11,983,805	7.63%	$914,749
	6.81%	1/9/2018	1/9/1998	$4,000,000	$257	$7,521	$3,992,222	6.88%	$274,648
	7.61%	12/2/2019	2/12/1997	$12,000,000	$2,576	$79,175	$11,918,249	7.68%	$915,153
	7.72%	2/1/2027	2/7/1997	$10,000,000	$0	$0	$10,000,000	7.78%	$778,476
Total Medium-Term Notes Series C				$40,000,000	$21,727	$86,696	$39,891,577		$3,035,891
Total Long-Term Debt Balance - ACTUAL				$1,023,230,000	$5,526,574	$1,749,344	$1,015,954,082	4.91%	$49,870,815

Delmarva Power & Light Company
Effective Cost Rate
Long-Term Debt
December 31, 2012
Delaware

				Original				Net	
Issue	Coupon Rate	Maturity	Offering Date	Principal Amount Issued	Expense of Issuance	(Premium)/ Discount	Net Amount to Company	Amount Per Unit	Yield to Maturity
First Mortgage Bonds									
	6.40%	12/1/2013	11/25/2008	$250,000,000	$1,925,105	$512,500	$247,562,395	$99.02	6.63%
	4.00%	6/1/2042	6/26/2012	$250,000,000	$2,506,150	$1,377,500	$246,116,350	$98.45	4.09%
Unsecured Notes									
	5.00%	11/15/2014	11/19/2004	$100,000,000	$928,224	$0	$99,071,776	$99.07	5.12%
	5.00%	6/1/2015	6/1/2005	$100,000,000	$853,194	$0	$99,146,806	$99.15	5.11%
	5.22%	12/30/2016	12/20/2006	$100,000,000	$600,000	$0	$99,400,000	$99.40	5.30%
Tax Exempt Fixed Rate Bonds									
	5.40%	2/1/2031	4/1/2010	$78,400,000	$1,406,618	$0	$76,993,382	$98.21	5.55%
Tax-Exempt Variable Rate Bonds									
	0.32%	10/1/2017	10/1/1987	$8,000,000	$315,360	$0	$7,684,640	$96.06	0.46%
	0.32%	10/1/2017	9/28/1988	$18,000,000	$270,107	$0	$17,729,893	$98.50	0.37%
	0.39%	10/1/2028	10/14/1993	$15,500,000	$275,796	$0	$15,224,204	$98.22	0.45%
	0.32%	10/1/2029	10/12/1994	$30,000,000	$440,787	$0	$29,559,213	$98.53	0.36%
	0.43%	7/1/2024	7/28/1999	$22,330,000	$669,900	$0	$21,660,100	$97.00	0.56%
	0.50%	7/1/2024	7/28/1999	$11,000,000	$220,000	$0	$10,780,000	$98.00	0.59%
Medium-Term Notes Series C									
	7.58%	2/1/2017	2/10/1997	$2,000,000	$15,000	$0	$1,985,000	$99.25	7.65%
	7.56%	2/1/2017	2/18/1997	$15,000,000	$112,500	$0	$14,887,500	$99.25	7.63%
	6.81%	1/9/2018	1/9/1998	$33,000,000	$247,500	$0	$32,752,500	$99.25	6.88%
	7.61%	12/2/2019	2/12/1997	$12,000,000	$90,000	$0	$11,910,000	$99.25	7.68%
	7.72%	2/1/2027	2/7/1997	$30,000,000	$225,000	$0	$29,775,000	$99.25	7.78%

TESTIMONY OF ROBERT B. HEVERT

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF ROBERT B. HEVERT
DOCKET NO. _____

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, Massachusetts 01701.

Q2. On whose behalf are you submitting this Direct Testimony?

A2. I am submitting this Direct Testimony before the Delaware Public Service Commission (Commission) on behalf of Delmarva Power & Light Company (Delmarva or the Company), a wholly-owned operating subsidiary of Pepco Holdings, Inc. (PHI).

Q3. Please describe your educational background.

A3. I hold a Bachelor's degree in Business and Economics from the University of Delaware, and an MBA with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q4. Please describe your experience in the energy and utility industries.

A4. I have worked in regulated industries for over twenty five years, having served as an executive and manager with consulting firms, a financial officer of a publicly-traded natural gas utility (at the time, Bay State Gas Company), and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues, including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in approximately 100 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies and the Federal Energy Regulatory Commission. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Attachment A to my Direct Testimony.

II. Purpose and Overview of Testimony

Q5. What is the purpose of your Direct Testimony?

A5. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Company's Cost of Equity (sometimes referred to as the Return on Equity or ROE) and to provide an assessment of the capital structure to be used for ratemaking purposes, as proposed in the Direct Testimony of Company Witness Boyle. My analyses and conclusions are supported by the data presented in Schedule (RBH)-1 through Schedule (RBH)-8, which have been prepared by me or under my direction.

Q6. What are your conclusions regarding the appropriate Cost of Equity and capital structure for the Company?

A6. My analyses indicate that the Company's Cost of Equity currently is in the range of 10.25% to 11.00%, and within that range, it is my view that an ROE of 10.50% is reasonable and appropriate. Consequently, the Company's proposed ROE, 10.25%, lies at the low end of that range. As such, I conclude that the Company's proposal is reasonable, if not conservative. As to its proposed capital structure, which includes 49.22% common equity and 50.78% long-term debt, I conclude that the Company's proposal is consistent with the capital structures that have been in place over several fiscal quarters at comparable operating utility companies. In light of its ongoing need to access external capital, and given the consistency of its proposal with similarly-situated utility companies, I conclude that the Company's proposed capital structure is reasonable and appropriate.

Q7. Please provide a brief overview of the analyses that led to your ROE recommendation.

A7. Equity analysts and investors use multiple methods to develop their return requirements for investments. In order to develop my ROE recommendation, I relied on three widely-accepted approaches: the Constant Growth Discounted Cash Flow (DCF) model; the Capital Asset Pricing Model (CAPM); and the Bond Yield Plus Risk Premium approach.

My recommendations and conclusions also consider the risks associated with (1) the Company's comparatively small size; and (2) flotation costs associated with equity issuances. While I did not make any explicit adjustments to my ROE estimates for those factors, I did take them into consideration in determining the range in which the Company's Cost of Equity likely falls.

Q8. How is the remainder of your Direct Testimony organized?

A8. The remainder of my Direct Testimony is organized as follows:

- <u>Section III</u> – Discusses the regulatory guidelines and financial considerations pertinent to the development of the cost of capital;

- Section IV – Explains my selection of the proxy group used to develop my analytical results;
- Section V – Explains my analyses and the analytical bases for my ROE recommendation;
- Section VI – Provides a discussion of specific business risks that have a direct bearing on the Company's Cost of Equity;
- Section VII – Highlights the current capital market conditions and their effect on the Company's Cost of Equity;
- Section VIII – Addresses the reasonableness of the Company's proposed capital structure; and
- Section IX – Summarizes my conclusions and recommendations.

III. Regulatory Guidelines and Financial Considerations

Q9. Please provide a brief summary of the guidelines established by the United States Supreme Court (the Court) for the purpose of determining the ROE.

A9. The Supreme Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia* (*Bluefield*); and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* (*Hope*).[1] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the

[1] *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

company's credit and to attract capital.

Q10. Does Delaware precedent provide similar guidance?

A10. Yes. In Order No. 8011, for example, the Commission stated:

> The requirement of a fair return recognizes that utilities compete for capital with other investments. Accordingly, the return which a utility investor can expect should be commensurate with the returns that could be expected on other comparable-risk investments. See J. BONBRIGHT, A. DANIELSON, and D. KAMERSCHEN, *Principles of Public Utility Rates*, at 316 (2d ed. 1988). In keeping with this, the United States and Delaware Supreme Courts have held that the return to a utility should be sufficient to assure confidence in the utility's financial integrity, to maintain its credit, and to attract capital. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 579 (1923); *Application of Wilmington Suburban Water Co.*, 211 A.2d 602 (Del. 1965).[2]

Based on those standards, the authorized ROE should provide the Company with the opportunity to earn a fair and reasonable return, and should enable efficient access to external capital under a variety of market conditions.

IV. Proxy Group Selection

Q11. As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for Delmarva?

A11. Since the ROE is a market-based concept, and Delmarva is not a publicly traded entity, it is necessary to establish a group of comparable publicly-traded companies to serve as its "proxy." Even if Delmarva were a publicly traded entity, short-term events could bias its market value during a given period of time. A significant benefit of using a proxy group is that it serves to moderate the effects of

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2 Public Service Commission of the State of Delaware, Docket No. 09-414, Order No. 8011, *In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed September 18, 2009), August 9, 2011, at 112.

anomalous, temporary events associated with any one company.

Q12. Does the selection of a proxy group suggest that analytical results will be tightly clustered around average (*i.e.*, mean) results?

A12. No. The DCF approach, for example, defines the Cost of Equity as the sum of the expected dividend yield and projected long-term growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to estimate the Cost of Equity from within that range. That determination necessarily must consider a wide range of both empirical and qualitative information.

Q13. Please provide a summary profile of Delmarva.

A13. Delmarva is a wholly-owned operating subsidiary of PHI (NYSE: POM). The Company provides electric transmission, distribution, and default supply service to approximately 303,000 customers in Delaware and 200,000 customers in Maryland.[3] The Company also provides natural gas supply and distribution service to approximately 125,000 customers in northern Delaware.[4] PHI's current long-term issuer credit rating from Standard & Poor's (S&P) is BBB+ (outlook: Stable), Baa3 (outlook: Stable) from Moody's Investors Service (Moody's), and BBB (outlook: Stable) from FitchRatings (Fitch). Delmarva currently is rated BBB+ (outlook: Stable) by S&P, Baa2 (outlook: Stable) by Moody's, and BBB+ (outlook: Stable) by

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3 *See*, Pepco Holdings, SEC Form 10-K for the fiscal year ended December 31, 2012, at 8.

4 *Ibid.*, at 10.

Fitch.[5]

Q14. How did you select the companies included in your proxy group?

A14. I began with the universe of companies that Value Line classifies as Electric Utilities, which includes a group of 49 domestic U.S. utilities, and applied the following screening criteria:

- I excluded companies that do not consistently pay quarterly cash dividends;
- All of the companies in my proxy group have been covered by at least two utility industry equity analysts;
- All of the companies in my proxy group have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- I excluded companies whose regulated operating income over the three most recently reported fiscal years represented less than 60.00% of combined income;
- I excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 90.00% of total regulated operating income; and
- I eliminated companies that are currently known to be party to a merger, or other significant transaction.

Q15. Did you include PHI in your analysis?

A15. No. In order to avoid the circular logic that would otherwise occur, it has been my consistent practice to exclude the subject company (or its parent) from the proxy group.

[5] Source: SNL Financial.

Q16. Why did you include vertically integrated utilities in your proxy group, when Delmarva is a transmission and distribution company?

A16. Although Delmarva is a transmission and distribution (T&D) company, there are no "pure play" state-jurisdictional electric T&D companies that may be used as a proxy for the Company's Delaware electric distribution operations. I therefore concluded that including vertically integrated electric companies in my proxy group is a reasonable approach for the purpose of estimating the Company's Cost of Equity.

Q17. What companies met those screening criteria?

A17. The criteria discussed above resulted in an initial proxy group of the following 13 companies: American Electric Power Company, Inc.; Cleco Corporation; Edison International; Empire District Electric Company; Great Plains Energy Inc.; Hawaiian Electric Industries, Inc.; IDACORP, Inc.; Otter Tail Corporation; Pinnacle West Capital Corporation; PNM Resources, Inc.; Portland General Electric Company; Southern Company; and Westar Energy, Inc.

Q18. Is this your final proxy group?

A18. No, I excluded Edison International (EIX) based on the most recently available financial information. Specifically, EIX recorded a loss of $1.7 billion in 2012 as a result of placing Edison Mission Energy, the subsidiary that owns and operated unregulated electric generating assets (including Homer City) into Chapter 11 bankruptcy and the divestiture of its Homer City assets.[6] In addition, EIX recorded a $1.05 billion loss resulting from an after-tax earnings charge (recorded in the fourth quarter of 2011) relating to the impairment of its Homer City, Fisk,

[6] *See*, Edison International, SEC Form 10-K for the fiscal year ended December 31, 2012, at 35.

Crawford, and Waukegan power plants, wind related charges, and other expenses.[7] Given the significant nature of those results, I have excluded EIX from the proxy group.

Q19. Based on the criteria and issues discussed above, what is the composition of your proxy group?

A19. The final proxy group is presented in Table 1.

Table 1: Final Proxy Group

Company	Ticker
American Electric Power Company, Inc.	AEP
Cleco Corporation	CNL
Empire District Electric Company	EDE
Great Plains Energy Inc.	GXP
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
Westar Energy, Inc.	WR

V. Cost of Equity Analysis

Q20. Please briefly discuss the ROE in the context of the regulated rate of return.

A20. Regulated utilities primarily use common stock and long-term debt to finance their capital investments. The overall rate of return (ROR) weighs the costs of the individual sources of capital by their respective book values. While the cost of debt

7 *Ibid.*, at 35-36.

and cost of preferred stock can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market information.

Q21. How is the required ROE determined?

A21. I estimated the ROE using analyses based on market data to quantify a range of investor expectations of required equity returns. By their very nature, quantitative models produce a range of results from which the market required ROE must be estimated. As discussed throughout my Direct Testimony, that estimation must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. Consequently, the key consideration in determining the ROE is to ensure that the overall analysis reasonably reflects investors' view of the financial markets in general and the subject company (in the context of the proxy companies) in particular.

Constant Growth DCF Model

Q22. Are DCF models widely used in regulatory proceedings?

A22. Yes. In my experience, the Constant Growth DCF model is widely recognized in regulatory proceedings, as well as in financial literature. Nonetheless, neither the DCF nor any other model should be applied without considerable judgment in the selection of data and the interpretation of results.

Q23. Please describe the DCF approach.

A23. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the Cost of Equity as the sum of the expected dividend yield and long-term growth rate, and is expressed as follows:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \quad \text{Equation [1]}$$

where P represents the current stock price, D_1 … D_∞ represent expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D_0\ (1+g)}{P} + g \quad \text{Equation [2]}$$

Equation [2] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected long-term annual growth rate.

In essence, the Constant Growth DCF model assumes that the total return received by investors includes the dividend yield, and the rate of growth. As explained below, under the model's assumptions, the rate of growth equals the rate of capital appreciation. That is, the model assumes that the investor's return is the sum of the dividend yield and the increase in the stock price.

Q24. What assumptions are required for the Constant Growth DCF model?

A24. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. Under those assumptions, dividends, earnings, book value, and the stock price all grow at the same, constant rate.

Q25. What market data did you use to calculate the dividend yield component of your DCF model?

A25. The dividend yield is based on the proxy companies' current annualized dividend, and average closing stock prices over the 30-, 90-, and 180-trading day periods as of February 15, 2013.

Q26. Why did you use three averaging periods to calculate an average stock price?

A26. I did so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, using 30-, 90-, and 180-day averaging periods reasonably balances those concerns.

Q27. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A27. Yes. Since utilities increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield.[8] That adjustment ensures that the expected dividend yield is representative of the coming twelve-month period, and does not overstate the dividends to be paid during that time.

Q28. Is it important to select appropriate measures of long-term growth in applying the DCF model?

A28. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [2] above) assumes a single growth estimate in perpetuity. This assumption requires a fixed payout ratio, and the same constant growth rate for earnings per share

8 *See*, Schedule (RBH)-1.

(EPS), dividends per share, and book value per share. Since dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth.

Q29. Please summarize your inputs to the Constant Growth DCF model.

A29. I used the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-, 90-, and 180-trading days ended February 15, 2013, for the term P_0; and
2. The annualized dividend per share as of February 15, 2013, for the term D_0.

I then calculated my DCF results using each of the following growth terms:

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates; and
3. The Value Line long-term earnings growth estimates.

Q30. How did you calculate the high and low DCF results?

A30. I calculated the proxy group mean high DCF results by using the maximum EPS growth rate as reported by Value Line, Zacks, and First Call for each proxy group company in combination with the dividend yield for each of the proxy group companies. The proxy group mean high results then reflect the average of the maximum DCF results for the proxy group as a whole. I used a similar approach to calculate the proxy group mean low results using instead the minimum of the Value Line, Zacks, and First Call growth rates for each company.

Q31. Did you make any adjustments to the growth rates in your DCF analyses?

A31. Yes. I note that the Value Line EPS growth estimate for Otter Tail Power

(OTTR) is more than two standard deviations from the unadjusted group mean. At the same time, earnings growth estimates from Zacks and First Call for OTTR are somewhat below the group mean, and are relatively similar to each other. Rather than eliminating OTTR's DCF estimates altogether, therefore, I removed the Value Line growth estimate.[9]

Q32. What are the results of your DCF analysis?

A32. My Constant Growth DCF results are summarized in Table 2, below (*see also*, Schedule (RBH)-1).

Table 2: DCF Results[10]

	Mean Low	*Mean*	*Mean High*
30-Day Average	9.00%	10.21%	11.63%
90-Day Average	9.09%	10.30%	11.71%
180-Day Average	9.08%	10.29%	11.71%

Q33. Did you give any weight to the Mean Low DCF results in developing your ROE range and recommendation?

A33. No, the mean low results are well below any reasonable estimate of the Company's Cost of Equity. Of the 1,392 rate cases since 1980 that disclosed the awarded ROE, for example, only one included an authorized ROE of 9.00% or lower.[11] On that basis alone, the mean low results are highly improbable. As such, I did not give those estimates any weight in arriving at my ROE range and recommendation.

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9 Please note that removing outlying growth rates may be considered for both high and low estimates. An alternative, and very reasonable approach, would be to consider both mean and median results.

10 DCF results presented in Table 2 are unadjusted (*i.e.*, prior to any adjustment for flotation costs).

11 Source: Regulatory Research Associates.

Q34. Did you undertake any additional analyses to support your recommendation?

A34. Yes. As noted earlier, I also applied the CAPM and Risk Premium analyses in estimating the Company's Cost of Equity.

CAPM Analysis

Q35. Please briefly describe the general form of the CAPM analysis.

A35. The CAPM analysis is a risk premium approach that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [3], the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$k = r_f + \beta(r_m - r_f) \quad \text{Equation [3]}$$

where:

k = the required market ROE for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In Equation [3], the term $(r_m - r_f)$ represents the Market Risk Premium.[12] According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

[12] The Market Risk Premium is defined as the incremental return of the market over the risk-free rate.

$$\beta_j = \frac{\sigma_j}{\sigma_m} x \, \rho_{j,m} \quad \text{Equation [4]}$$

Where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. The Beta coefficient therefore represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile, and have moved in tandem with the overall market. Consequently, if a company has a Beta coefficient of 1.00, it is as risky as the market and does not provide any diversification benefit.

Q36. Do you have concerns about the CAPM based on current and market conditions?

A36. Yes. For example, the risk-free rate, "r_f," is represented by the yield on long-term U.S. Treasury securities. During periods of increased equity market volatility, investors tend to allocate their capital to low-risk securities such as Treasury bonds, thereby bidding down the yield on those securities. In addition, since the 2008 Lehman Brothers bankruptcy filing, the Federal Reserve has focused on maintaining low long-term interest rates. Thus, even if investors were to allocate capital to more risky assets, Federal Reserve policy may have the continuing effect of maintaining low Treasury yields.

Even considering the effect of Federal Reserve policy, capital markets continue to change, by some measures quite significantly. For example, over the 90 trading days ended February 15, 2013, the 30-year Treasury yield ranged from a low of 2.72% to a high of 3.23%. In addition (and as discussed later in my Direct Testimony), the Equity Risk Premium is not constant, and tends to move in the opposite direction as changes in interest rates occur. Consequently, the CAPM results can be relatively volatile.

Q37. With those observations in mind, what assumptions did you include in your CAPM analysis?

A37. Since utility assets represent long-term investments, I used two different estimates of the long-term risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 3.12%); and (2) the near-term projected 30-year Treasury yield (*i.e.*, 3.25%).[13]

Q38. What Market Risk Premium did you use in your CAPM analysis?

A38. Because the model is forward-looking, I developed two forward-looking estimates of the Market Risk Premium. The first approach uses the market required return, less the current 30-year Treasury bond yield. To estimate the market required return, I calculated the average ROE based on the Constant Growth DCF model. To do so, I relied on data from Bloomberg and Capital IQ, respectively. For both Bloomberg and Capital IQ, I calculated the average expected dividend yield (using the same one-half growth rate assumption described earlier) and combined that amount with the average projected earnings growth rate to arrive at the average DCF result. I then subtracted the current 30-year Treasury yield from that amount to arrive

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[13] *See*, Blue Chip Financial Forecasts, Vol. 32, No. 2, February 1, 2013, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending June 2014. As noted above, the 30-year Treasury yield ranged from 2.72% to 3.23% in the 90 trading days ending February 15, 2013.

at the market DCF-derived *ex-ante* Market Risk Premium estimate. The results of those two calculations are provided in Schedule (RBH)-2.

Q39. Please describe the second approach.

A39. The second approach is based on the fundamental financial principle that investors require higher returns for higher risk. In essence, this approach uses market-based data to determine whether investors expect future risk to be higher, lower, or approximately equal to historical market risk. To the extent the market expects risk to be higher than historical levels, the Market Risk Premium would be higher than historical levels; the converse also is true.

In terms of its application, this approach relies on the Sharpe, which is the ratio of the long-term average Risk Premium for the S&P 500 Index, to the risk of that index.[14] The formula I used for calculating the Sharpe Ratio is expressed as follows:

$$S_x = \frac{(R_x - R_f)}{\sigma_x} \qquad \text{Equation [5]}$$

where:

S_x = Sharpe Ratio for the S&P 500 Index;

R_x = the average return of the S&P 500;

R_f = the rate of return of a risk-free security; and

σ_x = the standard deviation of the return on the S&P 500.

As shown in Schedule (RBH)-2, I calculated the constant Sharpe Ratio as the

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[14] The Sharpe Ratio is relied upon by financial professionals to assess the incremental return received for holding a risky (*i.e.*, more volatile) asset rather than a risk-free (*i.e.*, less volatile) asset. Risk is measured by the standard deviation of returns. That is, the higher the volatility of returns, the greater the risk.

ratio of the historical Market Risk Premium of 6.60% (the numerator of Equation [5] above)[15] and the historical standard deviation of 20.30% (the denominator of Equation [5]).[16] Equation [5] can be re-arranged as:

$$MRP = S_x \, x \, \sigma_{ex} \quad \text{Equation [6]}$$

Equation [6] basically states that the expected Market Risk Premium is determined by investors' historical required return per unit of risk (the historical Sharpe Ratio) times expected market risk. To measure expected market risk, I used the 30-day average of the Chicago Board Options Exchange's (CBOE) three-month volatility index (*i.e.*, the VXV) and the average of settlement prices over the same 30-day period of futures on the CBOE's one-month volatility index (*i.e.*, the VIX) for July 2013 through September 2013. Both of those indices are market-based, observable measures of investors' expectations regarding future market volatility.

Q40. What Beta coefficients did you use in your CAPM model?

A40. My approach includes the average reported Beta coefficient from Bloomberg and Value Line for each of the proxy group companies. While both of those services adjust their calculated (or raw) Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two

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15 *See*, Morningstar Inc., 2013 Ibbotson SBBI Risk Premia Over Time Report, Long-Horizon Equity Risk Premia Table A-1, at 9.

16 The standard deviation is calculated from data provided by Morningstar in its annual Valuation Yearbook. (*See*, Morningstar Inc., Ibbotson SBBI 2012 Valuation Yearbook, Large Company Stocks: Total Returns Table B-1, at 168-169). I recognize that the VIX forward settlement prices are liquid for approximately six to eight months; nonetheless, that data represents a market-based measure of expected volatility that should be considered in estimating the *ex-ante* Market Risk Premium.

years of data.[17]

Q41. What are the results of your CAPM analysis?

A41. The results of my CAPM analysis are summarized in Table 3, below (*see also*, Schedule (RBH)-4).

Table 3: Summary of CAPM Results

	Sharpe Ratio Derived Market Risk Premium	***Bloomberg Derived Market Risk Premium***	***Capital IQ Derived Market Risk Premium***
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (3.12%)	7.43%	10.19%	10.14%
Near Term Projected 30-Year Treasury (3.25%)	7.57%	10.32%	10.27%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (3.12%)	7.44%	10.20%	10.15%
Near Term Projected 30-Year Treasury (3.25%)	7.57%	10.33%	10.28%

Q42. Do you believe the CAPM results provide a reasonable range of ROE estimates at this time?

A42. Not entirely. As a practical matter, the low results are approximately 100 basis points below the lowest ROE ever authorized for an electric utility in at least 30 years. By that measure, the mean low results simply are not reasonable. As to the remaining results, as noted earlier in my Direct Testimony, the intended consequence of continued Federal intervention in the capital markets has been to maintain long-term Treasury yields at historically low levels. Since the CAPM defines the Cost of

17 Please note that while, in Docket No. 11-528 I separately calculated Beta coefficients, in this instance there is no meaningful difference between the Bloomberg Beta coefficients and those calculated over a 18-month period. Consequently, and for the purpose of narrowing the scope of analytical issues, I have not included calculated Beta coefficients in this proceeding.

Equity in terms of Treasury yields, the effect of those actions to decrease, rather substantially, the CAPM estimates. The effect of that policy, however, will not continue indefinitely; consensus forecasts call for the 30-year Treasury yield to increase to 4.70% percent (from the current level of approximately 3.00%) in the 2014-2018 timeframe.[18] On balance, then, I do not believe that the results presented in Table 3 fully reflect the appropriate range of ROE estimates.

Bond Yield Plus Risk Premium Approach

Q43. Please generally describe the Bond Yield Plus Risk Premium approach.

A43. This approach is based on the basic financial tenet that, since equity investors bear the residual risk of ownership, their returns are subject to more risk than are the returns to bondholders. As such, equity holders require a premium over the returns available to debt holders. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of an Equity Risk Premium[19] and a bond yield. The Equity Risk Premium is the difference between the historical Cost of Equity and long-term Treasury yields. Since we are calculating the risk premium for electric utilities, a reasonable approach is to use actual authorized returns for electric utilities as the historical measure of the Cost of Equity.

Q44. Please explain how you performed your Bond Yield Plus Risk Premium analysis.

A44. As discussed above, I first defined the Risk Premium as the difference between authorized ROEs and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield. I then gathered data from 1,392 electric utility rate proceedings

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18 *See*, Blue Chip Financial Forecasts, Vol.31, No. 12, December 1, 2012, at 14.

19 The Equity Risk Premium is defined as the incremental return that an equity investment provides over a risk-free rate.

between January 1, 1980 and February 15, 2013.[20] In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the final order (the lag period). In order to reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 201 days).

Because the data covers a number of economic cycles,[21] the analysis also may be used to assess the stability of the Equity Risk Premium. As noted above, the Equity Risk Premium is not constant over time; prior research has shown that it is directly related to expected market volatility, and inversely related to the level of interest rates.[22] That finding is particularly relevant given the historically low level of current Treasury yields.

Q45. How did you model the relationship between interest rates and the Equity Risk Premium?

A45. The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used the semi-log regression, in

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[20] Source: Regulatory Research Associates.

[21] *See*, National Bureau of Economic Research, *U.S. Business Cycle Expansion and Contractions.*

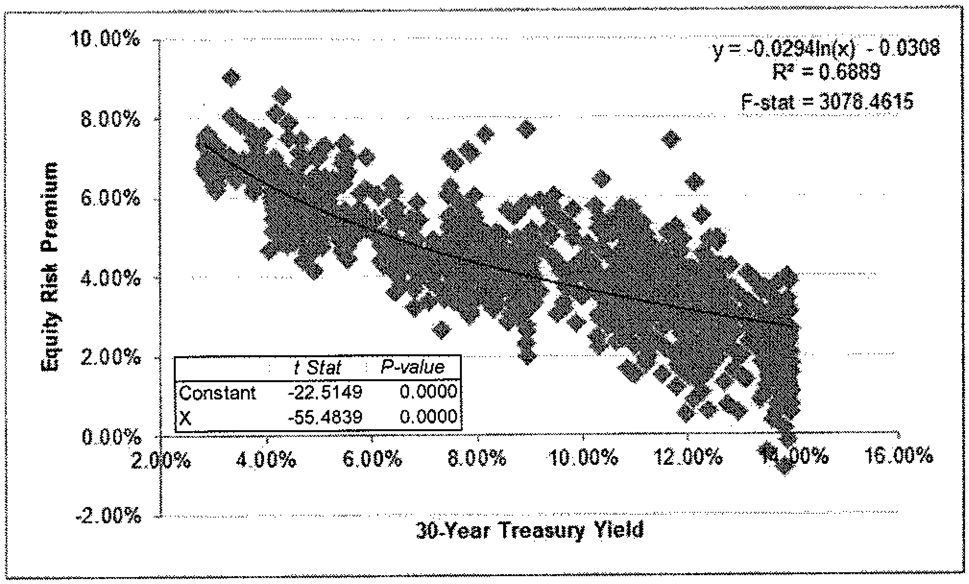
[22] *See, e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta(\mathrm{LN}(T_{30})) \qquad \text{Equation [7]}$$

As shown on Chart 1 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

Chart 1: Equity Risk Premium



As Chart 1 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.39% would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 1, however, the implied ROE is between 10.23% and 10.76% (*see*, Schedule (RBH)-5).

VI. Business Risks

Q46. What additional information did you consider in assessing the analytical results noted above?

A46. Because the analytical methods discussed above provide a range of estimates, there are several additional factors that should be taken into consideration when establishing a reasonable range for the Company's Cost of Equity. Those factors include: (1) the Company's comparatively small size; and (2) flotation costs associated with equity issuances.

Small Size Premium

Q47. Please explain the risk associated with small size.

A47. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect."[23] While empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts have noted the risks associated with small market capitalizations. Specifically, Ibbotson Associates noted that "[f]or small utilities, investors face additional obstacles, such as smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return."[24]

Q48. How does Delmarva compare in size to the proxy companies?

A48. Delmarva is somewhat smaller than the average for the proxy group companies, both in terms of number of customers and annual revenues. Because

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[23] *See*, Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002, for a review of literature relating to the size effect.

[24] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

Delmarva is not a separately traded entity, an estimated stand-alone market capitalization for Delmarva must be calculated. Schedule (RBH)-6 shows this calculation. The implied market capitalization is calculated by applying the median market-to-book ratio for the proxy group of 1.35 to the Company's implied total common stock book equity of $0.37 billion.[25] The implied market capitalization based on that calculation is $0.50 billion, compared to the proxy group median of $2.58 billion, which indicates Delmarva is significantly smaller than the proxy group average on a market capitalization basis.

Q49. How did you evaluate the risks associated with the Company's relatively small size?

A49. In its *Risk Premia Over Time Report: 2012*, Morningstar Inc. (Morningstar) calculates the size premium for deciles of market capitalizations relative to the S&P 500 Index. As shown on Schedule (RBH)-6, based on recent market data, the average market capitalization of the proxy group is approximately $7.14 billion, and the median market capitalization of the proxy group is $2.58 billion, which correspond to the third and fifth deciles, respectively, of Morningstar's market capitalization data. Based on the Morningstar analysis, the proxy group has a size premium of 0.92% to 1.70%. The implied market capitalization for Delmarva is approximately $0.50 billion, which falls within the ninth decile and corresponds to a size premium of 2.70%, suggesting that a size premium as high as 178 basis points (2.70% – 0.92%) is expected for Delmarva relative to the proxy group. However, rather than propose a specific adjustment, I considered the effect of small size in determining where the

[25] Equity value of Delmarva's Delaware electric utility estimated from proposed rate base and recommended capital structure.

Company's ROE falls within the range of results.

Flotation Costs

Q50. What are flotation costs?

A50. Flotation costs are the costs associated with the sale of new issues of common stock. These include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance.

Q51. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A51. Flotation costs are part of capital costs, which are properly reflected on the balance sheet under "paid in capital" rather than current expenses on the income statement. Flotation costs are incurred over time, just as investments in rate base or debt issuance costs. As a result, the great majority of flotation costs are incurred prior to the test year, but remain part of the cost structure during the test year and beyond.

Q52. How did you calculate the flotation cost recovery adjustment?

A52. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. My flotation cost adjustment recognizes the costs of issuing equity that were incurred by PHI and the proxy group companies in their most recent two issuances. As shown in Schedule (RBH)-7, an adjustment of 0.15% (*i.e.*, 15 basis points) reasonably represents flotation costs for the Company.

Q53. Are you proposing to adjust your recommended ROE by 15 basis points to reflect the effect of flotation costs on Delmarva's ROE?

A53. No, I am not. Rather, I have considered the effect of flotation costs, in addition to the Company's other business risks, in determining where the Company's

ROE falls within the range of results.

VII. Capital Market Environment

Q54. Do economic conditions influence the required cost of capital and required return on common equity?

A54. Yes. As discussed in Section V, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions.

Q55. Have you reviewed any specific indices to assess the relationship between current market conditions and investor return requirements?

A55. Yes. I considered the relationship between Treasury yields and the Cost of Equity as a principal measure of current capital market conditions. As discussed below, this measure provides information that is relevant to the implementation of models used to estimate the Cost of Equity and in the interpretation of the model results.

Relationship Between Historically Low Treasury Yields and the Cost of Equity

Q56. As a preliminary matter, has the Cost of Equity fallen in tandem with the recent decline in long-term Treasury yields?

A56. No. The fear of taking the risks of equity ownership has motivated many investors to move their capital into the relative safety of Treasury securities. In doing so, investors bid down yields to the point that they currently are receiving yields on ten-year Treasury bonds that are below the rate of inflation.[26] In effect, those investors have been willing to accept a *negative* real return on Treasury bonds rather

[26] *See*, for example, *Treasurys Slide After Lackluster Sale*, The Wall Street Journal, August 8, 2012.

than be subject to the risk of owning equity securities.

At the same time, the Federal Reserve's policy of buying longer-dated Treasury securities and selling short-term securities also may have had the effect of lowering long-term Treasury yields. That is, of course, the objective of the Federal Reserve's "maturity extension program" which began in June 2011.[27] As the Federal Reserve noted:

> Under the maturity extension program, the Federal Reserve intends to sell or redeem a total of $667 billion of shorter-term Treasury securities by the end of 2012 and use the proceeds to buy longer-term Treasury securities. This will extend the average maturity of the securities in the Federal Reserve's portfolio.
>
> ***
>
> By reducing the supply of longer-term Treasury securities in the market, this action should put downward pressure on longer-term interest rates, including rates on financial assets that investors consider to be close substitutes for longer-term Treasury securities. The reduction in longer-term interest rates, in turn, will contribute to a broad easing in financial market conditions that will provide additional stimulus to support the economic recovery.[28]

Consequently, two factors are at work: (1) the continued focus on capital preservation on the part of investors has caused them to reallocate capital to the relative safety of Treasury securities, thereby bidding up the price and bidding down the yield; and (2) the Federal Reserve's continued policy of buying long-term Treasury securities in order to lower the yield. As the Federal Reserve noted in its

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27 On September 13, 2012, the Federal Reserve announced that, in addition to continuing the maturity extension program announced in June 2011, it would begin buying mortgage-backed securities at a pace of $40 billion per month. (*See*, Federal Reserve Press Release, dated September 13, 2012.) At its January 2013 meeting, the Federal Open Market Committee voted to continue its policy of purchasing, on a monthly basis, $45 billion and $40 billion of longer-term Treasury securities, and mortgage-backed securities, respectively. During that meeting, various participants expressed concern with potentially adverse consequences of the Federal Reserve's continued accommodative policies. (*See*, Minutes of the Federal Open Market Committee, January 29-30, 2013, at 13-15.)

28 http://www.federalreserve.gov/monetarypolicy/maturityextensionprogram.htm

June 2012 Open Market Committee meeting minutes, the effect of those two factors has been a continued decline in Treasury yields:

> Yields on longer-dated nominal and inflation-protected Treasury securities moved down substantially, on net, over the intermeeting period. The yield on nominal 10-year Treasury securities reached a historically low level immediately following the release of the May employment report. A sizable portion of the decline in longer-term Treasury rates over the period appeared to reflect greater safe-haven demands by investors, along with some increase in market participants' expectations of further Federal Reserve balance sheet actions.[29]

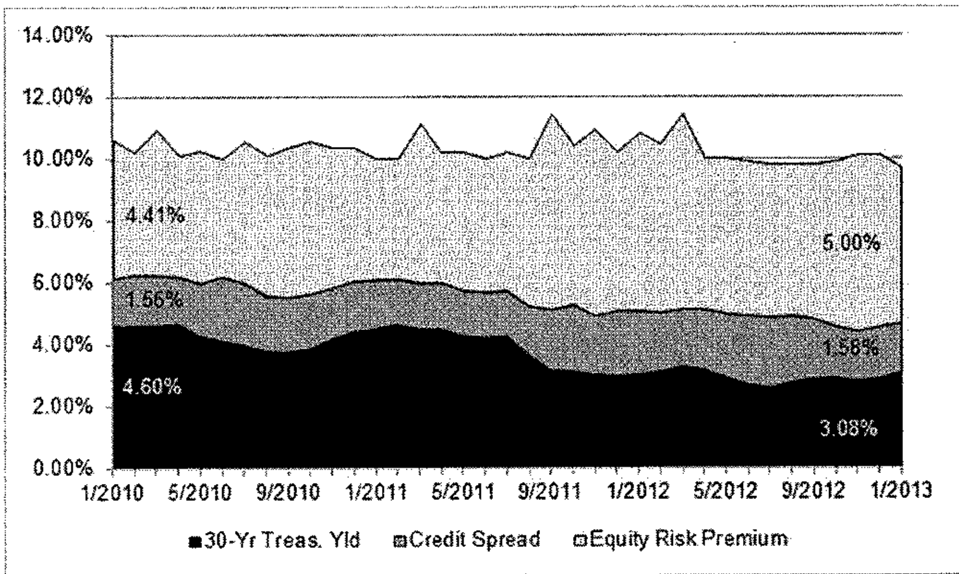
At issue, then, is whether those two factors, the continuing tendency of investors to seek the relative safety of long-term Treasury securities and the Federal Reserve's policy of lowering long-term Treasury yields, have caused the required return on equity to fall in a fashion similar to the recent decline in interest rates. In large measure, that issue becomes a question of whether the premium required by debt and equity investors also has remained constant as Treasury yields have decreased. To the extent that the risk premium has increased, the higher premium has offset, at least to some degree, the decline in Treasury yields, indicating that the Cost of Equity has not fallen in lock step with the decline in interest rates.

One method of performing that analysis is to analyze recently authorized ROEs for electric utilities on a "build-up" basis. From that perspective, the required market return represents the sum of: (1) long-term Treasury yields; (2) the credit spread (*i.e.*, the incremental return required by debt investors over Treasury yields; and (3) the Equity Risk Premium (*i.e.*, the incremental return required by equity investors over the cost of debt). As shown on Chart 2 (below), that has been the case;

[29] Minutes of the Federal Open Market Committee June 19–20, 2012, at 4.

both debt and equity investors have required increased risk premiums as long-term Treasury yields have fallen.

Chart 2: Components of Authorized ROE (2010 – 2013)[30]



VIII. Capital Structure

Q57. What is the Company's proposed capital structure?

A57. As described in the Direct Testimony of Company Witness Boyle, the Company has proposed a capital structure comprised of 49.22% common equity and 50.78% long-term debt.

Q58. Is there a generally accepted approach to developing the appropriate capital structure for a regulated electric utility?

A58. Yes, there are a number of generally accepted approaches to developing the appropriate capital structure. The reasonableness of the approach depends on the nature and circumstances of the subject company. In cases where the subject

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30 Sources: Regulatory Research Associates and Bloomberg Professional.

company does not issue its own securities, it may be reasonable to look to the parent's capital structure or to develop a "hypothetical" capital structure based on the proxy group companies or other industry data. Regardless of the approach taken, however, it is important to consider the resulting capital structure in light of industry norms and investor requirements. That is, the capital structure should enable the subject company to maintain its financial integrity, thereby enabling access to capital at competitive rates under a variety of economic and financial market conditions.

Q59. How does the capital structure affect the Cost of Equity?

A59. The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations, and is a function of the percentage of debt (or financial leverage) in its capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress (*i.e.*, financial risk) also increases. Since the capital structure can affect the subject company's overall level of risk,[31] it is an important consideration in establishing a just and reasonable rate of return.

Q60. Please discuss your analysis of the capital structures of the proxy group companies.

A60. I calculated the average capital structure for each of the proxy group companies over the last eight quarters. As shown in Schedule (RBH)-8, the mean of the proxy group actual capital structures is 52.05% common equity and 47.95% long-

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[31] *See*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

term debt. The common equity ratios range from 48.30% to 60.00%. Based on that review, it is apparent that the Company's proposed capital structure is generally consistent with the capital structures of the proxy group companies.

Q61. What is the basis for using average capital components rather than a point-in-time measurement?

A61. Measuring the capital components at a particular point in time can skew the capital structure by the specific circumstances of a particular period. Therefore, it is more appropriate to normalize the relative relationship between the capital components over a period of time.

Q62. What is your conclusion regarding an appropriate capital structure for Delmarva?

A62. Considering the average actual equity ratio of 52.05% for the proxy group companies, I believe that Delmarva's proposed common equity ratio of 49.22% is appropriate as it is consistent with the proxy group companies.

IX. Conclusions and Recommendation

Q63. What is your conclusion regarding the Company's Cost of Equity?

A63. I believe that a rate of return on common equity in the range of 10.25% to 11.00% represents the range of equity investors' required rate of return for investment in electric utilities similar to Delmarva in today's capital markets. Within that range, it is my view that an ROE of 10.50% is reasonable and appropriate. Consequently, the Company's proposed 10.25% ROE is at the low end of a reasonable range of estimates of its Cost of Equity.

As discussed earlier in my testimony, my recommendation reflects analytical results based on a proxy group of primarily electric utilities. My recommendation also takes into consideration the Company's risk profile relative to the proxy group analytical results with respect to its: (1) relatively small size; and (2) flotation costs associated with equity issuances.

Lastly, I conclude that the Company's proposed capital structure, which consists of 49.22% common equity and 50.78% long-term debt, is consistent with industry practice and on that basis, is reasonable and appropriate.

Q64. Does this conclude your Direct Testimony?

A64. Yes, it does.

Robert B. Hevert, CFA
Managing Partner
Sussex Economic Advisors, LLC

Mr. Hevert is an economic and financial consultant with broad experience in regulated industries. He has an extensive background in the areas of corporate finance, corporate strategic planning, energy market assessment, mergers, and acquisitions, asset-based transactions, feasibility and due diligence analyses, and providing expert testimony in litigated proceedings. Mr. Hevert has significant management experience with both operating and professional services companies.

REPRESENTATIVE PROJECT EXPERIENCE

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including: cost of capital for ratemaking purposes; the proposed transfer of power purchase agreements; procurement of residual service electric supply; the legal separation of generation assets; merger-related synergies; assessment of economic damages; and specific financing transactions. Services provided include collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises. Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last resort obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the U.S. and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

PROFESSIONAL HISTORY

Sussex Economic Advisors, LLC (2012 – Present)
Managing Partner

Concentric Energy Advisors, Inc. (2002 – 2012)
President

Navigant Consulting, Inc. (1997 – 2001)
Managing Director (2000 – 2001)
Director (1998 – 2000)
Vice President, REED Consulting Group (1997 – 1998)

Bay State Gas Company (now Columbia Gas Company of Massachusetts) (1987 – 1997)
Vice President and Assistant Treasurer

Boston College (1986 – 1987)
Financial Analyst

General Telephone Company of the South (1984 – 1986)
Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts at Amherst, 1984
B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991
Association for Investment Management and Research
Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics, including:

- Generation Asset Valuation and the Use of Real Options
- Retail and Wholesale Market Entry Strategies
- The Use Strategic Alliances in Restructured Energy Markets
- Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
- Nuclear Asset Valuation and the Divestiture Process

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	09/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Department of Public Utility Control				
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. FC1087	Return on Equity
Federal Energy Regulatory Commission				
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Hawaiian Public Utilities Commission				
Hawaiian Electric Light Company	08/12	Hawaiian Electric Light Company	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	
Maine Public Utilities Commission				
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Minnesota Public Utilities Commission				
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	NSP-Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	NSP Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Dominion North Carolina Power	03/12	Dominion Resources	Docket No. E-22, Sub 479	Return on Equity (electric)
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity (electric)
North Dakota Public Service Commission				
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
South Carolina Electric & Gas	10/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
South Dakota Public Utilities Commission				
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10175	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10171	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline - Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Virginia State Corporation Commission				
Columbia Gas Of Virginia, Inc.	06/06	Columbia Gas Of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-0014	Capital Structure

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] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.88	$44.20	4.25%	4.32%	3.38%	3.47%	3.00%	3.28%	7.32%	7.61%	7.80%
Cleco Corp.	CNL	$1.35	$42.22	3.20%	3.27%	3.00%	3.00%	8.00%	4.67%	6.25%	7.94%	11.33%
Empire District Electric	EDE	$1.00	$21.10	4.74%	4.93%	N/A	10.20%	5.50%	7.85%	10.37%	12.78%	15.18%
Great Plains Energy Inc.	GXP	$0.87	$21.19	4.11%	4.24%	7.10%	7.20%	5.50%	6.60%	9.72%	10.84%	11.45%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.54	4.67%	4.84%	6.35%	6.70%	9.00%	7.35%	11.17%	12.19%	13.88%
IDACORP, Inc.	IDA	$1.52	$45.18	3.36%	3.42%	4.00%	4.00%	2.00%	3.33%	5.40%	6.75%	7.43%
Otter Tail Corporation	OTTR	$1.19	$26.63	4.47%	4.59%	6.00%	5.00%	N/A	5.50%	9.58%	10.09%	10.60%
Pinnacle West Capital Corp.	PNW	$2.18	$53.04	4.11%	4.25%	6.90%	7.50%	6.50%	6.97%	10.74%	11.22%	11.76%
PNM Resources, Inc.	PNM	$0.58	$20.93	2.77%	2.93%	8.35%	9.30%	16.00%	11.22%	11.24%	14.14%	18.99%
Portland General Electric Company	POR	$1.08	$28.30	3.82%	3.89%	4.07%	1.99%	5.50%	3.85%	5.84%	7.74%	9.42%
Southern Company	SO	$1.96	$43.77	4.48%	4.59%	4.98%	4.86%	5.00%	4.95%	9.45%	9.54%	9.59%
Westar Energy, Inc.	WR	$1.32	$29.92	4.41%	4.57%	6.38%	7.50%	7.50%	7.13%	10.93%	11.70%	12.08%
PROXY GROUP MEAN				4.03%	4.15%	5.50%	5.89%	6.68%	6.06%	9.00%	10.21%	11.63%
PROXY GROUP MEDIAN				4.18%	4.29%	6.00%	5.85%	5.50%	6.05%	9.65%	10.47%	11.39%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of February 15, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

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] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.88	$43.47	4.32%	4.40%	3.38%	3.47%	3.00%	3.28%	7.39%	7.68%	7.87%
Cleco Corp.	CNL	$1.35	$41.30	3.27%	3.34%	3.00%	3.00%	8.00%	4.67%	6.32%	8.01%	11.40%
Empire District Electric	EDE	$1.00	$20.84	4.80%	4.99%	N/A	10.20%	5.50%	7.85%	10.43%	12.84%	15.24%
Great Plains Energy Inc.	GXP	$0.87	$21.10	4.12%	4.26%	7.10%	7.20%	5.50%	6.60%	9.74%	10.86%	11.47%
Hawaiian Electric Industries, Inc.	HE	$1.24	$25.77	4.81%	4.99%	6.35%	6.70%	9.00%	7.35%	11.31%	12.34%	14.03%
IDACORP, Inc.	IDA	$1.52	$43.89	3.46%	3.52%	4.00%	4.00%	2.00%	3.33%	5.50%	6.85%	7.53%
Otter Tail Corporation	OTTR	$1.19	$25.04	4.75%	4.88%	6.00%	5.00%	N/A	5.50%	9.87%	10.38%	10.89%
Pinnacle West Capital Corp.	PNW	$2.18	$52.06	4.19%	4.33%	6.90%	7.50%	6.50%	6.97%	10.82%	11.30%	11.84%
PNM Resources, Inc.	PNM	$0.58	$21.07	2.75%	2.91%	8.35%	9.30%	16.00%	11.22%	11.22%	14.12%	18.97%
Portland General Electric Company	POR	$1.08	$27.40	3.94%	4.02%	4.07%	1.99%	5.50%	3.85%	5.97%	7.87%	9.55%
Southern Company	SO	$1.96	$43.99	4.46%	4.57%	4.98%	4.86%	5.00%	4.95%	9.42%	9.51%	9.57%
Westar Energy, Inc.	WR	$1.32	$29.22	4.52%	4.68%	6.38%	7.50%	7.50%	7.13%	11.04%	11.81%	12.19%
PROXY GROUP MEAN				4.12%	4.24%	5.50%	5.89%	6.68%	6.06%	9.09%	10.30%	11.71%
PROXY GROUP MEDIAN				4.26%	4.36%	6.00%	5.85%	5.50%	6.05%	9.80%	10.62%	11.44%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of February 15, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
American Electric Power Company, Inc.	AEP	$1.88	$42.69	4.40%	4.48%	3.38%	3.47%	3.00%	3.28%	7.47%	7.76%	7.95%
Cleco Corp.	CNL	$1.35	$41.68	3.24%	3.31%	3.00%	3.00%	8.00%	4.67%	6.29%	7.98%	11.37%
Empire District Electric	EDE	$1.00	$21.05	4.75%	4.94%	N/A	10.20%	5.50%	7.85%	10.38%	12.79%	15.19%
Great Plains Energy Inc.	GXP	$0.87	$21.36	4.07%	4.21%	7.10%	7.20%	5.50%	6.60%	9.68%	10.81%	11.42%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.77	4.63%	4.80%	6.35%	6.70%	9.00%	7.35%	11.13%	12.15%	13.84%
IDACORP, Inc.	IDA	$1.52	$42.96	3.54%	3.60%	4.00%	4.00%	2.00%	3.33%	5.57%	6.93%	7.61%
Otter Tail Corporation	OTTR	$1.19	$24.05	4.95%	5.08%	6.00%	5.00%	N/A	5.50%	10.07%	10.58%	11.10%
Pinnacle West Capital Corp.	PNW	$2.18	$52.17	4.18%	4.32%	6.90%	7.50%	6.50%	6.97%	10.81%	11.29%	11.84%
PNM Resources, Inc.	PNM	$0.58	$20.61	2.81%	2.97%	8.35%	9.30%	16.00%	11.22%	11.28%	14.19%	19.04%
Portland General Electric Company	POR	$1.08	$27.16	3.98%	4.05%	4.07%	1.99%	5.50%	3.85%	6.01%	7.91%	9.59%
Southern Company	SO	$1.96	$45.26	4.33%	4.44%	4.98%	4.86%	5.00%	4.95%	9.30%	9.38%	9.44%
Westar Energy, Inc.	WR	$1.32	$29.49	4.48%	4.64%	6.38%	7.50%	7.50%	7.13%	11.00%	11.76%	12.14%
PROXY GROUP MEAN				4.11%	4.24%	5.50%	5.89%	6.68%	6.06%	9.08%	10.29%	11.71%
PROXY GROUP MEDIAN				4.25%	4.38%	6.00%	5.85%	5.50%	6.05%	9.88%	10.70%	11.39%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of February 15, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Sharpe Ratio Derived *Ex-Ante* Market Risk Premium

[1]	[2]	[3]	[4]	[5]
RP_h	Vol_h	VOL_e	Historical Sharpe Ratio	RP_e
6.60%	20.30%	18.54%	32.52%	6.03%

	[6]	[7]	[8]	[9]
Date	VXV	Jul 13 VIX Futures	Aug 13 VIX Futures	Sep 13 VIX Futures
2/15/2013	14.26	17.75	18.40	19.05
2/14/2013	14.43	17.70	18.35	18.90
2/13/2013	14.63	17.65	18.20	18.90
2/12/2013	14.53	17.70	18.40	18.95
2/11/2013	14.68	17.80	18.45	19.00
2/8/2013	14.80	18.00	18.60	19.20
2/7/2013	15.19	18.25	18.90	19.45
2/6/2013	15.14	18.30	18.95	19.50
2/5/2013	15.30	18.50	19.05	19.60
2/4/2013	15.79	18.55	19.15	19.70
2/1/2013	14.79	18.45	19.00	19.50
1/31/2013	15.55	18.50	19.05	19.55
1/30/2013	15.42	18.40	18.95	19.50
1/29/2013	14.74	18.05	18.70	19.25
1/28/2013	15.07	18.20	18.75	19.35
1/25/2013	14.66	18.10	18.75	19.30
1/24/2013	14.67	18.20	18.85	19.45
1/23/2013	14.50	18.25	18.90	19.50
1/22/2013	14.72	18.55	19.20	19.80
1/18/2013	15.29	19.15	19.80	20.45
1/17/2013	16.08	19.80	20.45	21.05
1/16/2013	16.24	20.10	20.75	21.35
1/15/2013	16.33	20.30	20.80	21.35
1/14/2013	16.29	20.30	20.85	21.40
1/11/2013	16.01	20.50	21.00	21.60
1/10/2013	16.12	20.60	21.15	21.75
1/9/2013	16.50	20.90	21.50	22.15
1/8/2013	16.45	21.15	21.75	22.35
1/7/2013	16.45	21.20	21.75	22.35
1/4/2013	16.34	21.15	21.75	22.30
Average:		18.54		

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 Cols. [6] to [9])
[4] Equals [1] / [2]
[5] Equals [3] x [4]
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Source: Bloomberg Professional
[9] Source: Bloomberg Professional

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
13.00%	3.12%	9.88%

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

Ex-Ante Market Risk Premium
Market DCF Method Based - Capital IQ

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
12.93%	3.12%	9.81%

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

Bloomberg and Value Line Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
American Electric Power Company, Inc.	AEP	0.627	0.65
Cleco Corp.	CNL	0.770	0.65
Empire District Electric	EDE	0.759	0.65
Great Plains Energy Inc.	GXP	0.767	0.75
Hawaiian Electric Industries, Inc.	HE	0.735	0.70
IDACORP, Inc.	IDA	0.806	0.70
Otter Tail Corporation	OTTR	0.766	0.90
Pinnacle West Capital Corp.	PNW	0.715	0.70
PNM Resources, Inc.	PNM	0.680	0.90
Portland General Electric Company	POR	0.748	0.75
Southern Company	SO	0.523	0.55
Westar Energy, Inc.	WR	0.695	0.70
Mean		0.716	0.72

Notes:
[1] Source: Bloomberg Professional
[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 Results		
	Risk-Free Rate	Average Beta Coefficient	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF Derived	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF
PROXY GROUP BLOOMBERG BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	3.12%	0.716	6.03%	9.88%	9.81%	7.43%	10.19%	10.14%
Near-Term Projected 30-Year Treasury [10]	3.25%	0.716	6.03%	9.88%	9.81%	7.57%	10.32%	10.27%
Mean						7.50%	10.26%	10.21%

			Ex-Ante Market Risk Premium			CAPM Results		
	Risk-Free Rate	Average Beta Coefficient	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF Derived	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	3.12%	0.717	6.03%	9.88%	9.81%	7.44%	10.20%	10.15%
Near-Term Projected 30-Year Treasury [10]	3.25%	0.717	6.03%	9.88%	9.81%	7.57%	10.33%	10.28%
Mean						7.50%	10.27%	10.22%

Notes:
[1] *See Notes [9] and [10]*
[2] Source: Schedule (RBH)-3
[3] Source: Schedule (RBH)-2
[4] Source: Schedule (RBH)-2
[5] Source: Schedule (RBH)-2
[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. 2, February 1, 2013, at 2

Bond Yield Plus Risk Premium

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
Current	-3.08%	-2.94%	3.12%	7.11%	10.23%
Near Term Projected	-3.08%	-2.94%	3.25%	6.99%	10.24%
Long-Term Projected	-3.08%	-2.94%	5.10%	5.66%	10.76%

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. 2, February 1, 2013, at 2,
Long Term Projected = Blue Chip Financial Forecasts, Vol. 31, No. 12, December 1, 2012, at 14
[4] Equals [1] + [2] x ln([3])
[5] Equals [3] + [4]

Small Size Premium

	[1] Customers (Mil)	[2] ($Bil)
Delmarva Power & Light Company Equity	0.30	$0.37
Median Market to Book for Comp Group		1.35
Delmarva Power Implied Market Capitalization		$0.50

Company Name	Ticker	[3] Customers (Mil)	[4] Market Cap ($Bil)	[5] Market to Book Ratio
American Electric Power Company, Inc.	AEP	4.3	$21.45	1.41
Cleco Corp.	CNL	0.3	$2.56	1.71
Empire District Electric	EDE	0.2	$0.89	1.22
Great Plains Energy Inc.	GXP	0.8	$3.25	0.97
Hawaiian Electric Industries, Inc.	HE	0.4	$2.59	1.63
IDACORP, Inc.	IDA	0.5	$2.27	1.24
Otter Tail Corporation	OTTR	0.1	$0.96	1.70
Pinnacle West Capital Corp.	PNW	1.1	$5.82	1.40
PNM Resources, Inc.	PNM	0.7	$1.67	1.02
Portland General Electric Company	POR	0.8	$2.14	1.20
Southern Company	SO	4.4	$38.26	2.02
Westar Energy, Inc.	WR	0.7	$3.78	1.31
MEDIAN		0.7	$2.58	1.35
MEAN		1.2	$7.14	1.40

Decile	Market Capitalization ($Mil) [6] Low	High	Size Premium
2	$ 7,747.951	$ 17,541.302	0.76%
3	$ 4,250.360	$ 7,686.611	0.92%
4	$ 2,772.831	$ 4,227.668	1.14%
5	$ 1,912.240	$ 2,759.391	1.70%
6	$ 1,346.619	$ 1,909.051	1.72%
7	$ 822.077	$ 1,346.528	1.73%
8	$ 514.459	$ 818.065	2.46%
9	$ 254.604	$ 514.209	2.70%
10	$ 1.139	$ 253.761	6.03%

Notes:
[1] SEC Form 10-K for the fiscal year ended December 31, 2012, at 8
[2] Application for Increase in Rates
[3] Source: SNL Financial
[4] Source: Bloomberg, 30-day average
[5] Source: Bloomberg, 30-day average
[6] Source: Ibbotson Associates, 2013 Ibbotson SBBI Risk Premia Over Time Report

Flotation Cost Adjustment

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

Company	Date	Shares Issued	Offering Price	Underwriting Discount [i]	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%
American Electric Power Company, Inc.	4/1/2009	69,000,000	$24.50	$0.7350	$400,000	$23.76	$51,115,000	$1,690,500,000	$1,639,385,000	3.024%
American Electric Power Company, Inc.	2/27/2003	57,500,000	$20.95	$0.6285	$550,000	$20.31	$36,688,750	$1,204,625,000	$1,167,936,250	3.046%
Cleco Corp.	8/14/2006	6,900,000	$23.75	$0.8900	$225,000	$22.83	$6,366,000	$163,875,000	$157,509,000	3.885%
Cleco Corp.	11/9/2004	2,000,000	$18.50	$0.6475	$200,000	$17.75	$1,495,000	$37,000,000	$35,505,000	4.041%
Empire District Electric	12/6/2007	3,450,000	$23.00	$0.9775	$250,000	$21.95	$3,622,375	$79,350,000	$75,727,625	4.565%
Empire District Electric	6/15/2006	3,795,000	$20.25	$0.8600	$250,000	$19.32	$3,513,700	$76,848,750	$73,335,050	4.572%
Great Plains Energy Inc.	5/12/2009	11,500,000	$14.00	$0.4900	$500,000	$13.47	$6,135,000	$161,000,000	$154,865,000	3.811%
Great Plains Energy Inc.	5/17/2006	7,002,450	$27.50	$0.8938	$500,000	$26.53	$6,758,790	$192,567,375	$185,808,585	3.510%
Hawaiian Electric Industries, Inc.	12/2/2008	5,750,000	$23.00	$0.8625	$300,000	$22.09	$5,259,375	$132,250,000	$126,990,625	3.977%
Hawaiian Electric Industries, Inc.	3/10/2004	2,300,000	$51.86	$2.0744	$150,000	$49.72	$4,921,120	$119,278,000	$114,356,880	4.126%
IDACORP, Inc.	12/9/2004	4,025,000	$30.00	$1.2000	$300,000	$28.73	$5,130,000	$120,750,000	$115,620,000	4.248%
Otter Tail Corporation	9/19/2008	5,175,000	$30.00	$1.0875	$400,000	$28.84	$6,027,813	$155,250,000	$149,222,188	3.883%
Otter Tail Corporation	12/7/2004	3,335,000	$25.45	$0.9500	$300,000	$24.41	$3,468,250	$84,875,750	$81,407,500	4.086%
Pinnacle West Capital Corp.	4/8/2010	6,900,000	$38.00	$1.3300	$190,000	$36.64	$9,367,000	$262,200,000	$252,833,000	3.572%
Pinnacle West Capital Corp.	4/27/2005	6,095,000	$42.00	$1.3650	$250,000	$40.59	$8,569,675	$255,990,000	$247,420,325	3.348%
PNM Resources, Inc.	12/6/2006	5,750,000	$30.79	$1.0760	$250,000	$29.67	$6,448,500	$177,042,500	$170,594,000	3.642%
PNM Resources, Inc.	3/23/2005	3,910,000	$26.76	$0.8697	$200,000	$25.84	$3,600,527	$104,631,600	$101,031,073	3.441%
Portland General Electric Company	3/5/2009	12,477,500	$14.10	$0.4935	$375,000	$13.58	$6,532,646	$175,932,750	$169,400,104	3.713%
Portland General Electric Company	6/12/2007	23,658,106	$26.00	$0.7800	$700,000	$25.19	$19,153,323	$615,110,756	$595,957,433	3.114%
Southern Company	12/6/2000	28,750,000	$28.50	$0.9200	$490,000	$27.56	$26,940,000	$819,375,000	$792,435,000	3.288%
Westar Energy, Inc.	11/4/2010	8,625,000	$25.54	$0.8939	$250,000	$24.62	$7,959,888	$220,282,500	$212,322,613	3.613%
Westar Energy, Inc.	5/29/2008	6,900,000	$24.28	$0.8498	$325,000	$23.38	$6,188,620	$167,532,000	$161,343,380	3.694%
Mean							$10,749,926	$317,788,207		
							WEIGHTED AVERAGE FLOTATION COSTS:			3.383%

Notes:
[i] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

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]
					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	Average Earnings Growth	DCF k(e)	Flotation Adjusted DCF k(e)
American Electric Power Company, Inc.	AEP	$1.88	$44.20	4.25%	4.32%	4.47%	3.38%	3.47%	3.00%	3.28%	7.61%	7.76%
Cleco Corp.	CNL	$1.35	$42.22	3.20%	3.27%	3.39%	3.00%	3.00%	8.00%	4.67%	7.94%	8.05%
Empire District Electric	EDE	$1.00	$21.10	4.74%	4.93%	5.10%	N/A	10.20%	5.50%	7.85%	12.78%	12.95%
Great Plains Energy Inc.	GXP	$0.87	$21.19	4.11%	4.24%	4.39%	7.10%	7.20%	5.50%	6.60%	10.84%	10.99%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.54	4.67%	4.84%	5.01%	6.35%	6.70%	9.00%	7.35%	12.19%	12.36%
IDACORP, Inc.	IDA	$1.52	$45.18	3.36%	3.42%	3.54%	4.00%	4.00%	2.00%	3.33%	6.75%	6.87%
Otter Tail Corporation	OTTR	$1.19	$26.63	4.47%	4.59%	4.75%	6.00%	5.00%	N/A	5.50%	10.09%	10.25%
Pinnacle West Capital Corp.	PNW	$2.18	$53.04	4.11%	4.25%	4.40%	6.90%	7.50%	6.50%	6.97%	11.22%	11.37%
PNM Resources, Inc.	PNM	$0.58	$20.93	2.77%	2.93%	3.03%	8.35%	9.30%	16.00%	11.22%	14.14%	14.25%
Portland General Electric Company	POR	$1.08	$28.30	3.82%	3.89%	4.03%	4.07%	1.99%	5.50%	3.85%	7.74%	7.88%
Southern Company	SO	$1.96	$43.77	4.48%	4.59%	4.75%	4.98%	4.86%	5.00%	4.95%	9.54%	9.70%
Westar Energy, Inc.	WR	$1.32	$29.92	4.41%	4.57%	4.73%	6.38%	7.50%	7.50%	7.13%	11.70%	11.86%
PROXY GROUP MEAN											10.21%	10.36%

DCF Result Adjusted For Flotation Costs:	10.36%
DCF Result Unadjusted For Flotation Costs:	10.21%
Difference (Flotation Cost Adjustment):	0.15% [12]

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 [9])
[5] Equals [4] / (1 - 0.0338)
[6] Source: Zacks
[7] Source: Yahoo! Finance
[8] Source: Value Line
[9] Equals Average([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals average [11] - average [10]

Proxy Group Capital Structure

Company	Ticker	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	2011Q1	2010Q4	Average
		% Long-Term Debt								
American Electric Power Company, Inc.	AEP	47.17%	47.82%	48.54%	47.06%	47.29%	49.15%	49.93%	50.02%	48.37%
Cleco Corporation	CNL	50.23%	49.62%	51.62%	51.71%	52.48%	52.25%	53.02%	52.67%	51.70%
Empire District Electric Company	EDE	46.89%	47.50%	47.09%	47.71%	48.05%	49.04%	48.97%	49.07%	48.04%
Great Plains Energy Inc.	GXP	44.67%	50.51%	48.14%	48.07%	48.87%	47.00%	46.41%	47.77%	47.68%
Hawaiian Electric Industries, Inc.	HE	44.30%	44.64%	41.42%	41.63%	42.41%	42.78%	44.14%	44.17%	43.18%
IDACORP, Inc.	IDA	48.47%	49.63%	49.09%	49.41%	49.56%	51.05%	51.16%	53.39%	50.22%
Otter Tail Corporation	OTTR	49.65%	49.77%	49.52%	49.72%	46.64%	46.83%	46.76%	46.84%	48.22%
Pinnacle West Capital Corporation	PNW	43.70%	45.40%	45.64%	45.54%	47.94%	47.56%	47.43%	47.03%	46.28%
PNM Resources, Inc.	PNM	48.92%	49.60%	49.57%	50.07%	47.85%	48.62%	48.45%	48.45%	48.94%
Portland General Electric Company	POR	50.26%	50.53%	50.63%	51.06%	52.10%	52.22%	52.26%	53.17%	51.53%
Southern Company	SO	51.99%	52.78%	53.52%	52.57%	48.86%	49.78%	49.41%	50.73%	51.21%
Westar Energy, Inc.	WR	39.70%	40.62%	39.95%	38.64%	39.34%	40.38%	40.76%	40.63%	40.00%
Mean		47.16%	48.20%	47.89%	47.77%	47.62%	48.06%	48.22%	48.66%	47.95%

Operating Company Capital Structure

Operating Company	Parent	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	2011Q1	2010Q4
		% Long-Term Debt							
Appalachian Power Company	AEP	55.18%	55.27%	55.38%	55.93%	55.81%	56.86%	58.47%	55.79%
AEP Texas Central Company	AEP	49.95%	51.09%	54.22%	36.23%	39.16%	52.74%	55.01%	55.15%
Indiana Michigan Power Company	AEP	50.39%	50.58%	50.45%	50.87%	50.90%	50.94%	51.14%	51.53%
Kentucky Power Company	AEP	53.54%	53.88%	54.24%	54.39%	54.38%	54.58%	54.50%	55.16%
Ohio Power Company	AEP	45.62%	46.06%	46.51%	47.88%	46.08%	45.66%	45.48%	46.57%
Public Service Company of Oklahoma	AEP	50.31%	51.07%	51.60%	51.48%	51.44%	52.49%	54.79%	53.55%
Southwestern Electric Power Company	AEP	49.58%	50.73%	51.45%	48.15%	48.01%	49.68%	50.42%	50.85%
AEP Texas North Company	AEP	52.45%	52.76%	52.71%	53.07%	53.65%	53.92%	54.12%	54.48%
Kingsport Power Company	AEP	40.08%	40.06%	39.65%	40.44%	41.33%	41.00%	40.88%	42.04%
Wheeling Power Company	AEP	24.64%	26.74%	29.22%	32.13%	32.12%	33.66%	34.47%	35.11%
Cleco Power LLC	CNL	50.23%	49.62%	51.62%	51.71%	52.48%	52.25%	53.02%	52.67%
Empire District Electric Company	EDE	46.89%	47.50%	47.09%	47.71%	48.05%	49.04%	48.97%	49.07%
KCP&L Greater Missouri Operations Company	GXP	41.91%	52.74%	47.76%	47.72%	47.58%	48.41%	45.48%	48.45%
Kansas City Power & Light Company	GXP	47.44%	48.27%	48.52%	48.41%	50.16%	45.59%	47.34%	47.10%
Hawaiian Electric Company, Inc.	HE	44.30%	44.64%	41.42%	41.63%	42.41%	42.78%	44.14%	44.17%
Idaho Power Co.	IDA	48.47%	49.63%	49.09%	49.41%	49.56%	51.05%	51.16%	53.39%
Otter Tail Power Company	OTTR	49.65%	49.77%	49.52%	49.72%	46.64%	46.83%	46.76%	46.84%
Arizona Public Service Company	PNW	43.70%	45.40%	45.64%	45.54%	47.94%	47.56%	47.43%	47.03%
Public Service Company of New Mexico	PNM	48.92%	49.60%	49.57%	50.07%	47.85%	48.62%	48.45%	48.45%
Portland General Electric Company	POR	50.26%	50.53%	50.63%	51.06%	52.10%	52.22%	52.26%	53.17%
Georgia Power Company	SO	50.39%	52.10%	49.83%	48.27%	48.06%	49.27%	48.83%	48.68%
Alabama Power Company	SO	52.48%	53.19%	54.43%	53.47%	52.71%	53.29%	53.54%	53.46%
Gulf Power Company	SO	51.27%	51.69%	51.65%	52.39%	52.21%	52.55%	52.48%	53.29%
Mississippi Power Company	SO	53.83%	54.12%	58.18%	56.17%	42.46%	44.01%	42.79%	47.49%
Kansas Gas and Electric Company	WR	40.73%	41.70%	42.15%	42.45%	42.30%	43.23%	43.48%	43.00%
Westar Energy (KPL)	WR	38.68%	39.54%	37.74%	34.82%	36.37%	37.53%	38.04%	38.26%

Source: SNL Financial

Proxy Group Capital Structure

Company	Ticker	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	2011Q1	2010Q4	Average
		% Common Equity								
American Electric Power Company, Inc.	AEP	52.83%	52.18%	51.46%	52.94%	52.71%	50.85%	50.07%	49.98%	51.63%
Cleco Corporation	CNL	49.77%	50.38%	48.38%	48.29%	47.52%	47.75%	46.98%	47.33%	48.30%
Empire District Electric Company	EDE	53.11%	52.50%	52.91%	52.29%	51.95%	50.96%	51.03%	50.93%	51.96%
Great Plains Energy Inc.	GXP	55.33%	49.49%	51.86%	51.93%	51.13%	53.00%	53.59%	52.23%	52.32%
Hawaiian Electric Industries, Inc.	HE	55.70%	55.36%	58.58%	58.37%	57.59%	57.22%	55.86%	55.83%	56.82%
IDACORP, Inc.	IDA	51.53%	50.37%	50.91%	50.59%	50.44%	48.95%	48.84%	46.61%	49.78%
Otter Tail Corporation	OTTR	50.35%	50.23%	50.48%	50.28%	53.36%	53.17%	53.24%	53.16%	51.78%
Pinnacle West Capital Corporation	PNW	56.30%	54.60%	54.36%	54.46%	52.06%	52.44%	52.57%	52.97%	53.72%
PNM Resources, Inc.	PNM	51.08%	50.40%	50.43%	49.93%	52.15%	51.38%	51.55%	51.55%	51.06%
Portland General Electric Company	POR	49.74%	49.47%	49.37%	48.94%	47.90%	47.78%	47.74%	46.83%	48.47%
Southern Company	SO	48.01%	47.22%	46.48%	47.43%	51.14%	50.22%	50.59%	49.27%	48.79%
Westar Energy, Inc.	WR	60.30%	59.38%	60.05%	61.36%	60.66%	59.62%	59.24%	59.37%	60.00%
Mean		52.84%	51.80%	52.11%	52.23%	52.38%	51.94%	51.78%	51.34%	52.05%

Operating Company Capital Structure

Operating Company	Parent	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	2011Q1	2010Q4
		% Common Equity							
Appalachian Power Company	AEP	44.82%	44.73%	44.62%	44.07%	44.19%	43.14%	41.53%	44.21%
AEP Texas Central Company	AEP	50.05%	48.91%	45.78%	63.77%	60.84%	47.26%	44.99%	44.85%
Indiana Michigan Power Company	AEP	49.61%	49.42%	49.55%	49.13%	49.10%	49.06%	48.86%	48.47%
Kentucky Power Company	AEP	46.46%	46.12%	45.76%	45.61%	45.62%	45.42%	45.50%	44.84%
Ohio Power Company	AEP	54.38%	53.94%	53.49%	52.12%	53.92%	54.34%	54.52%	53.43%
Public Service Company of Oklahoma	AEP	49.69%	48.93%	48.40%	48.52%	48.56%	47.51%	45.21%	46.45%
Southwestern Electric Power Company	AEP	50.42%	49.27%	48.55%	51.85%	51.99%	50.32%	49.58%	49.15%
AEP Texas North Company	AEP	47.55%	47.24%	47.29%	46.93%	46.35%	46.08%	45.88%	45.52%
Kingsport Power Company	AEP	59.92%	59.94%	60.35%	59.56%	58.67%	59.00%	59.12%	57.96%
Wheeling Power Company	AEP	75.36%	73.26%	70.78%	67.87%	67.88%	66.34%	65.53%	64.89%
Cleco Power LLC	CNL	49.77%	50.38%	48.38%	48.29%	47.52%	47.75%	46.98%	47.33%
Empire District Electric Company	EDE	53.11%	52.50%	52.91%	52.29%	51.95%	50.96%	51.03%	50.93%
KCP&L Greater Missouri Operations Company	GXP	58.09%	47.26%	52.24%	52.28%	52.42%	51.59%	54.52%	51.55%
Kansas City Power & Light Company	GXP	52.56%	51.73%	51.48%	51.59%	49.84%	54.41%	52.66%	52.90%
Hawaiian Electric Company, Inc.	HE	55.70%	55.36%	58.58%	58.37%	57.59%	57.22%	55.86%	55.83%
Idaho Power Co.	IDA	51.53%	50.37%	50.91%	50.59%	50.44%	48.95%	48.84%	46.61%
Otter Tail Power Company	OTTR	50.35%	50.23%	50.48%	50.28%	53.36%	53.17%	53.24%	53.16%
Arizona Public Service Company	PNW	56.30%	54.60%	54.36%	54.46%	52.06%	52.44%	52.57%	52.97%
Public Service Company of New Mexico	PNM	51.08%	50.40%	50.43%	49.93%	52.15%	51.38%	51.55%	51.55%
Portland General Electric Company	POR	49.74%	49.47%	49.37%	48.94%	47.90%	47.78%	47.74%	46.83%
Georgia Power Company	SO	49.61%	47.90%	50.17%	51.73%	51.94%	50.73%	51.17%	51.32%
Alabama Power Company	SO	47.52%	46.81%	45.57%	46.53%	47.29%	46.71%	46.46%	46.54%
Gulf Power Company	SO	48.73%	48.31%	48.35%	47.61%	47.79%	47.45%	47.52%	46.71%
Mississippi Power Company	SO	46.17%	45.88%	41.82%	43.83%	57.54%	55.99%	57.21%	52.51%
Kansas Gas and Electric Company	WR	59.27%	58.30%	57.85%	57.55%	57.70%	56.77%	56.52%	57.00%
Westar Energy (KPL)	WR	61.32%	60.46%	62.26%	65.18%	63.63%	62.47%	61.96%	61.74%

TESTIMONY OF MICHAEL W. MAXWELL

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF MICHAEL W. MAXWELL
DOCKET NO. _____

Q1. Please state your name and position.

A1. My name is Michael W. Maxwell, Vice President Asset Management for Pepco Holdings, Inc. (PHI). I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What are your responsibilities in your role as Vice President, Asset Management?

A2. I am responsible for reliability planning for all distribution, transmission and substation facilities for PH utility companies. I am also responsible for the engineering and design of the transmission and substation facilities constructed by PHI. The PHI utility companies include Delmarva, Atlantic City Electric Company and The Potomac Electric Power Company.

Q3. Please state your educational background and professional experience.

A3. I received a Bachelor of Science in Electrical Engineering from the Virginia Military Institute in 1987. I have held various operations, engineering, and logistic/support services positions at PHI.

I began my career at Pepco in 1987 in substation engineering and was promoted to various positions within substation engineering and field operations until 1997. Subsequently, I have held positions as Manager, Forestville Service Center (overhead lines operations, maintenance, and construction); Manager, Distribution System Operations (remote operation of the Pepco distribution system); General Manager, System Operations;

Vice President Emergency Preparedness; and Vice President, Strategic Services. I have served as Vice President, Asset Management since June 2008.

Q4. What is the purpose of your Direct Testimony?

A4. The purpose of my testimony is to:

- Provide information supporting the Delmarva construction program and the Company's progress in enhancing the reliability of its distribution system.
- Support the Reliability Plant Adjustment as presented in Company Witness Ziminsky's Direct Testimony
- Demonstrate that the Company's reliability investment is appropriate and necessary.

This testimony was prepared by me or under my direct supervision and control. The sources for my testimony are Company records, and public documents. I also rely upon my personal knowledge and experience.

DELMARVA'S CONSTRUCTION PROGRAM

Q5. Please describe the Company's construction program.

A5. The Delmarva construction budgets for 2012 and 2013 total $374.4 million. The 2012 Delmarva distribution budget was $75.4 million and has been increased to $87.8 million in 2013 for a total of $163.2 million.

The 2012 and 2013 distribution projects include investments that support the connection of new customers, projects that maintain and improve the reliability of the electric system and projects to accommodate increased load. These projects are further explained below.

Q6. Please describe the types of projects included in the distribution category.

A6. The distribution category of the construction budget is composed of three areas of work: Customer Driven, Reliability, and Load Growth.

The Customer Driven category represents projects required by customers, including, but not limited to new service connections, service rearrangements and heavy ups, and work performed at the direction of government agencies such as electric plant relocations that support road and highway construction projects.

The Reliability category reflects the construction of assets designed to maintain and enhance the reliability of the electric system. These projects include the upgrading of distribution feeders, replacing and upgrading Underground Residential Distribution (URD) cable installations, substation improvements and the installation of new technology and equipment such as Distribution Automation (DA) systems. DA devices are installed on groups of related feeders, and can automatically identify and isolate faults quickly and restore service to customers in the unaffected parts of the system. DA enhances reliability by isolating outage locations and minimizing the overall impacts (reducing the length) of outages to customers.

In 2012 and in 2013 Delmarva increased efforts to improve feeder performance through the Priority Feeder and Feeder Improvement programs. The Annual Priority Feeder program is designed to improve System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance of the system's lowest-performing feeders in accordance with Delaware Public Service Commission Regulation Docket No. 50. The Feeder Improvement program identifies feeders not previously identified in the Priority Feeder program that demonstrate lower reliability performance and feeders where specific customers have experienced a relatively higher level of repeat interruptions[1]. By addressing the reliability of these worst-performing feeders, the two feeder remediation programs intend to maintain and improve the experience of all Delmarva customers over time.

Load Growth projects include upgrading of existing feeders to increase their capacity to serve projected load of exiting customers, construction of new feeders in areas of the system where customer growth is occurring, and installation of substation equipment to provide additional electric capacity. Load Growth projects seek to maintain the Company's ability to transfer load and maintain continuity of service under various operating conditions, including both summer and winter peak load conditions.

Q7. Please discuss the Delmarva 2012 construction budget, and the 2013-2017 construction plan.

A7. The Delmarva 2012 expenditures and 2013 -2017 plan are presented in Table 1.

1 Based on Customers Experiencing Multiple Interruptions (CEMI) performance.

Delmarva Delaware
2012 Expenditure
and
Five Year Plan 2013 – 2017
Dollars in Millions

Table 1

Distribution	2012	2013	2014	2015	2016	2017	Total 2013 through 2017
Customer Driven	$12.6	$12.1	$11.9	$12.1	$12.6	$13.0	**$61.7**
Reliability	$64.1	$71.4	$58.9	$59.2	$60.3	$59.2	**$309.1**
Load	$2.8	$4.3	$6.1	$4.2	$4.5	$7.4	**$26.6**
Total	**$79.5**	**$87.8**	**$76.9**	**$75.7**	**$77.4**	**$79.6**	**$397.4**

The five year Reliability construction plan, 2013 through 2017, presents a balanced investment program aimed at maintaining the Company's improvement to distribution system reliability performance. Maintaining reliability performance requires continuing investment in the system. System performance cannot be maintained and improved without the ongoing replacements of system infrastructure, upgrades to the system's capacity to serve load, as well as the introduction of new technologies, such as Distribution Automation, that can shorten outage durations where this technology has been installed and meet the evolving needs of Delmarva's customers and the modern, electronics-based economy.

Q8. Have the Company's investments in reliability infrastructure improved its system reliability performance?

A8. Yes. The Company's investments in reliability infrastructure have improved the Company's performance as measured by SAIFI and SAIDI. From 2010 to 2012, Delmarva's system SAIFI performance has improved by 22%, and, during the same period, Delmarva's system SAIDI performance has been improved by 27%. Table 2 illustrates these improvements.

Delmarva Delaware
System SAIFI and SAIDI (IEEE Exclusion Criteria)
2010-2012

Table 2

Reliability Performance	2010	2011	2012	% Change 2010-2012
SAIFI	1.47	1.41	1.14	22%
SAIDI	199	192	146	27%
Docket No. 50 SAIDI Performance Target	295	295	295	n/a

Q9. What metrics does the Company use to judge the effectiveness of its reliability program?

A9. The Company uses two approaches when it looks at its reliability performance: compliance with Delaware PSC Electric Service Reliability and Quality Standards (also known as Docket No. 50), and year over year performance comparisons of system and individual feeder SAIFI and SAIDI data.

Q10. How has the company performed against the Electric Service Reliability and Quality Standards?

A10. The Electric Service Reliability and Quality Standards (also known as Docket No. 50) establish a maximum SAIDI target of 295 minutes per year. Delmarva acknowledges that in 2012 it is meeting and exceeding its Electric Service Reliability and Quality Standards SAIDI requirement of 295 minutes per year by 149 minutes, or approximately 51%. However, the

Company sees the standard as a minimum performance standard for meeting the expectations of its customers and will continue to seek to perform above the minimum standard. Delmarva does not believe that it should be satisfied merely with meeting the minimum performance standard, nor do we believe that striving to meet the minimum is the best approach for Delmarva's customers or the State.

Q11. What is the objective of Delmarva's Reliability plan?

A11. The Company's goal is to continue to provide safe and reliable electric distribution service to its customers. This entails striving for improvement by investing in, and improving, its distribution system. The safety and reliability performance of the system is not linear with respect to investment in the system and the productivity of those investments; necessary investments will not always result in a similar improvement in performance. The distribution system is aging and regularly experiences damaging events beyond the Company's control, but which require remediation to maintain reliability performance. While severe weather events are generally excluded from the calculation Delmarva's reliability performance statistics, the system is impacted by severe weather that weakens the system and leads to increased outages at later dates.

Similarly, we must expect that there will be weather events that fall just short of constituting excludable events. Outages resulting from damaging events are most effectively limited by continuous maintenance and improvement of the system.

Q12. What should customers expect from the Delmarva reliability program?

A12. Customers should expect continuing improvements in the reliability of the service they receive. They should expect reliable and safe performance along with fewer outages, and, when they do experience inevitable interruptions in service, shorter restoration times.

Maintaining system reliability is not just good business practice. In today's electronics based-economy, electric system reliability is a minimum requirement for businesses in evaluating opportunities for economic investment, development and growth. Businesses do not want to locate in an area where system performance is poor. In addition, system reliability is necessary to meet customer expectations.

Further, the improvement to reliability will help attract new customers to Delaware. Large commercial and industrial customers, large retailers, electronic commerce such as banking and data centers, and other businesses depend on reliable electric service to function competitively in the modern digitally-based economy. A community that has reliable electric service is more likely to attract, maintain and grow these businesses than one that does not.

Q13. **How does Delmarva's Reliability program support the Reliability Plant Adjustment presented in the Direct Testimony of Company Witness Ziminsky?**

A13. The Company is requesting that the Commission approve the cost recovery method identified in Adjustment 26. This adjustment reflects the continuing improvements that the Company is accomplishing in its reliability program and are provided to customers with the completion of every reliability asset that the Company puts in place.

Q14. Does this conclude your Direct Testimony?

A14. Yes, it does.

TESTIMONY OF JAY C. ZIMINSKY

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF JAY C. ZIMINSKY
DOCKET NO. _____

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 are your responsibilities in your role as Manager of Revenue Requirements?

A2. I am responsible for the coordination of revenue requirement determinations in Delaware, Maryland and New Jersey as well as coordinating various other regulatory compliance matters.

Q3. Please state your educational background and professional experience.

A3. I received a Bachelor of Science Degree in Business Administration with a concentration in Accounting from Drexel University in 1988 and a Masters in Business Administration, with a concentration in Finance, from the University of Delaware in 1996. I earned my Certified Public Accountant certification in the State of Pennsylvania in 1988.

In 1988, I joined Price Waterhouse as a Tax Associate. In 1991, I joined Delmarva as a Staff Accountant in the General Accounting section of the Controller's Department. In 1994, I joined the Management Information Process Redesign team as a Senior Accountant. In 1995, I joined the Conectiv Enterprises Business & Financial Management team as a Senior Financial Analyst. In 1996, I was promoted to Finance & Accounting Manager of Conectiv Communications, where I was later promoted to Finance & Accounting Director (in

1999) and Vice President – Finance (in 2000). In 2002, I joined the PHI Treasury Department as Finance Manager. In 2006, I joined the PHI Regulatory Department and was promoted to my current position in October 2008, where my responsibilities include the coordination of revenue requirement determinations in New Jersey, Delaware and Maryland as well as coordinating various other regulatory compliance matters.

Q4. What is the purpose of your Direct Testimony?

A4. The purpose of my Direct Testimony is to present and explain the basis for the development of the Company's Delaware Distribution-related Revenue Requirement request. My testimony will first present the separation of Delmarva system costs into a distribution component and then into the Delaware Distribution component. I also present the per-book Earnings and Rate Base for use in this filing along with the quantification and support of certain adjustments. I summarize the adjustments being proposed by all the witnesses as well as the revenue requirement request of the Company. I sponsor certain adjustments which are both described in my testimony and have supporting detail that can be found in Schedules (JCZ) 1 – 30, which accompany this filing. I am also sponsoring certain Minimum Filing Requirements (MFR). These schedules, workpapers and the MFR were prepared under my direction and/or supervision.

FILING REQUIREMENTS

Q5. What MFR are you sponsoring?

A5. I am sponsoring the following filing requirements:

Schedule A	Period Definitions
Schedule C	Elements of the Increase & Items that

	Depart from Last Decision
Schedule 1	Financial Summary
Schedule 2	Rate Base Summary
Schedule 2A	Used and Useful Utility Plant
Schedule 2B	Intangible Assets
Schedule 2C	Accumulated Depreciation & Amortization, and Customer Advances
Schedule 2D	Accumulated Deferred Income Taxes & Investment Tax Credit
Schedule 2E	Materials and Supplies
Schedule 2F	Other Elements of Property and CWIP
Schedule 3	Summary of Net Operating Income
Schedule 3A, Page 1	Revenues
Schedule 3B	Operating Expenses
Schedule 3C	Payroll Costs
Schedule 3D	Executive Compensation
Schedule 3E	Sales Promotion and Advertising
Schedule 3F	Contributions
Schedule 3G	Association Dues
Schedule 3H	Rate Case Expense
Schedule 3I	Income Taxes and Provisions
Schedule 3J	Federal and State Income Taxes
Schedule 3K	Deferred Federal and State Income Taxes

Schedule 3L	Investment Tax Credit
Schedule 3M	Other Taxes
Schedule 3O	Other Income
Schedule 5	Revenue Conversion Factor

TEST PERIOD

Q6. What are the test year and the test periods presented in this filing?

A6. The test year, which is used for cost allocation purposes, is the actual twelve months data ending December 2012. The test period, which is used for the purpose of developing the Company's overall revenue requirement, is the same period.

Q7. Is this an appropriate test period?

A7. Yes. In the absence of the use of a fully forecasted test period, a test period with ratemaking adjustments represents a reasonable time period from which rates can be established for the rate effective period. For this filing, the rate effective period represents the period from November 2013 through October 2014. With the adjustments presented in this filing, this time period provides a matching of revenues, expenses and rate base consistent with Commission regulations and, in the absence of a fully forecasted test period, represents a reasonable basis for establishing the Company's revenue requirements for the rate effective period.

RATE INCREASE REQUEST

Q8. Have you prepared schedules that summarize the Company's rate increase request?

A8. Yes. Schedule (JCZ)-1, Page 1 presents the system electric and Delaware Distribution unadjusted rate base and earnings. Schedule (JCZ)-1, Page 2 presents a summary of the necessary financial and accounting data for the test period ending December 31, 2012.

Schedule (JCZ)-1, Page 2 displays a fully adjusted rate of return of only 4.26% as this rate of return translates to a return on equity of 3.60% for the test period ending December 2012. Also listed on (JCZ)-1, Page 2 is the responsible witness for each adjustment. Schedule (JCZ)-2 provides the calculation of the increase in revenues necessary to earn the 7.53% rate of return supported by the Direct Testimony of Company Witness Boyle. This schedule supports an increase of $42,043,757 and the impact on customer rates is discussed in the Direct Testimony of Company Witness Santacecilia. Schedule (JCZ)-3 presents the total electric system and Delaware distribution cash working capital. Schedules (JCZ)-4 through (JCZ)-32 present the proposed ratemaking adjustments in this filing.

Q9. Please summarize the contents of Schedules (JCZ)-1 and (JCZ)-2.

A9. Schedule (JCZ)-1, Page 1 presents the Company's unadjusted total system, total distribution and Delaware jurisdictional rate base and earnings results of operation for the provision of distribution service for the twelve months actual data ending December 31, 2012. Schedule (JCZ)-1, Page 2 provides a summary of the earnings and rate base amounts for each ratemaking adjustment along with the responsible witness. Schedule (JCZ)-2 provides the Company's proposed revenue requirement increase of $42,043,757.

Q10. Please describe the development of per books rate base and earnings.

A10. The rate base for the test year and test period is comprised of average balances and is summarized on Schedule (JCZ)-1. Earnings for the test year and test period are also summarized on Schedule (JCZ)-1.

The source of the data for the test year and test period consists of the Company's books and records provided in the Direct Testimony of Company Witness White. Detail for the test year and test period can be found in the workpapers contained in Book 1 that accompanies the Company's Application.

Earnings include Operating Revenues less Operating Expense and Interest on Customer Deposits plus the Allowance for Funds Used During Construction (AFUDC), as shown on Schedule (JCZ)-1. The per book rate base is detailed by component on Schedule (JCZ)-1. Additions to rate base are included as they represent investment in facilities used to serve the Company's customers as well as investor-supplied working capital necessary for the Company's day-to-day operations. Certain items are deducted from rate base as they represent funds supplied by customers (or at least not investor-provided). Rate base includes Net Plant, Construction Work in Progress (CWIP), Materials and Supplies and Working Capital, less Accumulated Deferred Income Taxes, Unamortized Investment Tax Credits, Customer Advances and Customer Deposits.

ELECTRIC DISTRIBUTION COST OF SERVICE

Q11. Please discuss the development of Delmarva's cost of service on a distribution only-basis.

A11. The basis for Delmarva's electric distribution-only cost of service is the distribution accounts as specified in the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. In addition, I have allocated to distribution a portion of other Company cost elements functionalized as general, intangible and miscellaneous. The result of this separation or functionalization of costs is shown in Schedule (JCZ)-1.

Q12. Please describe the detail provided on Schedule (JCZ)-1.

A12. Schedule (JCZ)-1 shows the items of rate base, revenue, expense and return for Delmarva for the total Company in column (3), titled "Adjusted System Electric", and those same cost elements for the distribution function in Column (4), titled "Total Electric Distribution". I then allocate these electric distribution costs to the Delaware jurisdiction. Column (3) shows total System Electric rate base of $1,534,340,946, total operating revenues of $1,045,695,062, total operating expenses of $939,089,809, and operating income of $106,605,253. As described above, each cost element is separated into its Delaware electric distribution component. The Delaware electric distribution component is shown in column (5) of this schedule. The Delaware electric distribution rate base is $674,914,898 (an increase of $73,631,300 or 12.2%, compared to the December 2011 year-end rate base in Docket No. 11-528), total operating revenues are $176,519,552, total operating expenses are $147,481,308, and operating income is $29,038,244.

Q13. How are system electric distribution costs developed?

A13. Delmarva's overall costs consist of supply, transmission and distribution-related costs. Distribution plant costs are those costs contained in the FERC distribution accounts, numbers 360 to 373. Distribution expense costs are those costs contained in the FERC distribution accounts (inclusive of Customer Accounts Expense, Customer Service and Informational Expenses, and Sales Expenses), numbers 580 through 916. The exception to this process is Account 904, Uncollectible Accounts, which has to be functionalized. Transmission plant costs are from the FERC's transmission accounts, numbered 350 through 359. Transmission expense costs are those costs contained in the FERC transmission accounts, numbers 560 through 573.

Other costs, such as General Plant and Administrative and General Expenses, are contained in FERC accounts that are not specific to the transmission and distribution functions and thus have to be functionalized to produce the distribution-related portion of these costs.

Q14. Does the Company's rate base and earnings proposed in this Docket conform to the last litigated Electric decision in Docket No. 09-414?

A14. Yes, the Company made a concerted effort to file a case that was consistent with the Commission's decision in Docket No. 09-414; however, there are three items that differ, which I have outlined below:

- The Company has included CWIP in per books rate base with the corresponding accrued AFUDC in earnings since many of the projects are technically complete, with AFUDC no longer being accrued, and serving customers but their costs have not yet been transferred to plant in service. While the Commission did not include CWIP in rate base in that decision, the Commission did indicate that it was within their discretion in future cases to determine whether CWIP should be included in rate base. The Company requests that the Commission consider including CWIP in rate base in this filing.
- The Company has used a year-end, not average, rate base to better reflect the assets and liabilities which will be serving customers during the rate effective period. This change is described later in my Direct Testimony.
- While the Company removed executive incentive compensation in this filing, it is requesting that the Commission include in rates the incentive compensation for non-executive employees as I explain later in my Direct Testimony.

Q15. Was a lead/lag study prepared by the Company to determine the cash working capital requirement in its current filling?

A15. Yes. The results of the lead/lag study are reflected in Schedules (JCZ)-3. The total per books distribution Delmarva Power cash working capital requirement is $20,410,066. The Delaware distribution cash working capital requirement is $10,887,807 as shown in Schedule (JCZ)-3.

Q16. What period of time was the basis for preparing the lead/lag study?

A16. All transactions used in preparing the lead/lag study were from 2012 for revenues and 2010 from disbursements.

Q17. Have the factors developed in the lead/lag study been applied to the test period results of operations?

A17. Yes. The cash working capital lag factors were computed on historic data and applied to the test period results of operations.

RATEMAKING ADJUSTMENTS

Q18. Please list the pro forma adjustments that you are sponsoring in this proceeding.

A18. The pro forma adjustments that I am sponsoring are as follows:

- Adjustment No. 5 – Restate Regulatory Commission Expense;
- Adjustment No. 6 – Normalize Injuries and Damages;
- Adjustment No. 7 – Normalize Uncollectible Expense;
- Adjustment No. 8 – Reflect price changes associated with the Company's Wage and Federal Insurance Contributions Act (FICA) Expense;
- Adjustment No. 9 – Remove Employee Association Expense;

- Adjustment No. 10 – Reflect Proforma Benefits Expense;
- Adjustment No. 11 – Remove Executive Incentive Compensation Expense;
- Adjustment No. 12 – Remove Certain Executive Compensation Expense;
- Adjustment No. 13 – Normalize Storm Restoration Expense;
- Adjustment No. 14 – Normalize Integrated Resource Planning (IRP) Recurring Expense;
- Adjustment No. 15 – Amortize IRP Deferred Costs;
- Adjustment No. 16 – Amortize Request for Proposal (RFP) Deferred Costs;
- Adjustment No. 17 – Reflect Proforma Advanced Metering Infrastructure (AMI) Operations and Maintenance (O&M) Expenses;
- Adjustment No. 18 – Reflect Proforma AMI O&M Savings;
- Adjustment No. 19 – Reflect Proforma AMI Depreciation and Amortization Expense;
- Adjustment No. 20 – Amortize Dynamic Pricing Regulatory Asset;
- Adjustment No. 21 – Reflect Dynamic Pricing O&M Expenses;
- Adjustment No. 22 – Reflect Proforma Dynamic Pricing Amortization Expense;
- Adjustment No. 23 – Amortize Direct Load Control (DLC) Regulatory Asset;
- Adjustment No. 24 – Annualize Depreciation Expense on Year-End Plant;
- Adjustment No. 25 – Normalize Other Taxes;
- Adjustment No. 26 – Reflect Forecasted Reliability Plant Closings from January 2013 through December 2013;
- Adjustment No. 27 – Amortize of Loss/Gain on Refinancings;

- Adjustment No. 28 – Remove Qualified Fuel Cell Provider-Related Costs;
- Adjustment No. 29 – Amortize OPEB Medicare Tax Subsidy Deferred Costs;
- Adjustment No. 30 – Remove Post-1980 (ITC) Investment Tax Credit Amortization;
- Adjustment No 31 – Recover Credit Facilities Expense;
- Adjustment No. 32 – Remove Renewable Portfolio Standard (RPS) Related Labor Costs; and
- Adjustments No. 33 and No. 34 – Interest Synchronization and Cash Working Capital (CWC) for the Proforma Adjustments.

The Company's overall revenue requirement also reflects ratemaking adjustments sponsored by Company Witness Santacecilia.

Q19. Why are you making these adjustments?

A19. These adjustments are being made to establish a level of earnings and rate base more representative of the rate effective period as a basis for providing just and reasonable rates. Many of these adjustments reflect previously approved ratemaking treatment by the Commission. Other adjustments have been made to assure that the rate effective period reflects a matching of all elements of the ratemaking formula for known and measurable changes. Workpapers supporting each of these adjustments are included in Book 4 of this filing.

Q20. Please describe Adjustment No. 5, which restates regulatory commission expense.

A20. Consistent with the treatment approved in Docket Nos. 94-22, 03-127, 05-304 and 09-414, the amount expensed in the test period was adjusted for two items. The first is to normalize the test period level of expense using a three-year average. The second item is to adjust the test period level of expense to reflect the cost of this filing, which includes the costs of Staff, amortized over a three-year period. This adjustment results in an $85,345 decrease to test year earnings and is detailed on Schedule (JCZ)-4.

Q21. Please describe Adjustment No. 6, which normalizes injuries and damages expense.

A21. Consistent with the treatment adopted in Docket Nos. 03-127, 05-304 and 09-414, I am including an adjustment to normalize Injuries and Damages Expense using a three year period. A normalized expense level in the cost of service mitigates the year-to-year expense volatility, which could occur and subsequently be factored into new base rates depending on the test period used. This adjustment will result in a $25,878 increase to test year earnings and is detailed on Schedule (JCZ) -5.

Q22. Please describe Adjustment No. 7, which normalizes the Company's uncollectible expense.

A22. Consistent with the treatment included in Docket Nos. 03-127, 05-304, 09-414 and 11-528, I have normalized the Company's test period level of uncollectible expense using a three-year average of this expense. By normalizing this expense, year-to-year expense volatility is mitigated. This adjustment detailed on Schedule (JCZ)-6 and results in a $93,186 increase to the test period earnings.

Q23. Please describe Adjustment No. 8, which reflects the Company's proposed wage and FICA Expense.

A23. Consistent with the treatment included in Docket Nos. 94-22, 03-127, 05-304 and 09-414, the Company's test period wage and FICA levels of expense were adjusted for the known price changes required to be made to be reflective of the rate effective period. These include:

- 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,
- an estimated wage increase of 2.00% 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 wage increase of 2.00% for IBEW Local 1307 effective in June 2013 for 12 months,
- an estimated 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.

These wage increases have been applied to the Company's test period salaries and wages to be reflective of the rate effective period, November 2013 through October 2014. Updates to estimated information will be provided during the course of the proceeding. This adjustment is detailed on Schedule (JCZ)-7 and reflects a decrease of $1,114,374 to test period earnings.

Q24. Please describe Adjustment No. 9, which removes employee association expense.

A24. Consistent with treatment adopted in Docket No. 09-414, the amount charged to expense for support of the Employees' Association was removed for ratemaking purposes.

This adjustment is detailed on Schedule (JCZ)-8 and results in a $53,123 increase to test year earnings.

Q25. Please describe Adjustment No. 10, which reflects price changes related to the Company's employee medical, dental and vision benefits program.

A25. Consistent with the treatment submitted in Docket No. 11-528 as well as the Commission's decision in Docket No. 09-414, this adjustment recognizes the increases in employee medical, vision and dental expenses expected in the rate effective period based on forecasts by the Company's expert benefits consultant, The Lake Consulting Group (Lake), which analyzes benefit cost trends each quarter in the Mid-Atlantic region. A copy of the most recent Lake study is attached as Schedules (JCZ)-9.1 – (JCZ)-9.3. The study shows that annual benefit costs are forecasted to increase as follows:

- Medical: The expected Average Rate of 9.5% is as follows: (average of the Company's two primary types of medical plan offering - Health Maintenance Organization (HMO) [9.4%] and Preferred Provider Organization (PPO) [9.6%]). HMO survey range is 7.9% – 12.0%. PPO survey range is 7.7% – 12.0%;
- Dental: Average Rate is 6.0%. Survey range is 5.0% – 7.8%;
- Vision: Average Rate is 6.0% (not specifically tracked in Lake study; however, Lake notes that these cost trends generally follow dental cost increase trends).

The Company is using the rates stated below for its projection of benefit costs for financial forecasting purposes. The Company is including these same rates in its projection of benefit expenses. The medical, dental, and vision increases requested by Delmarva are as follows:

- Medical: 8.00%;

- Dental: 5.00%; and
- Vision: 5.00%.

As shown in Schedule (JCZ)-9, the adjustment reflects a decrease of $318,199 to test period earnings.

Q26. Please describe Adjustment No. 11, which removes executive incentive compensation expense.

A26. This adjustment removes the test period level of expense associated with executive incentives based on precedent in Docket No. 09-414. These "compensation at risk" payments are an important component of the Company's total executive compensation, and are likely to continue to be so in the future. As such, the Company will likely seek recovery of these costs in future rate filings. As displayed on Schedule (JCZ)-10, the Company is removing $1,291,130 of test period earnings in this adjustment.

Q27. Please describe Adjustment No. 12, which removes certain executive compensation.

A27. Consistent with treatment approved in Docket No. 09-414, this adjustment removes the test level period of expense associated with certain executive compensation. These forms of compensation are shown in Schedule (JCZ)-11. As displayed in that same schedule, the Company is removing $23,393 of test period earnings related to these items.

Q28. Please describe Adjustment No. 13, which normalizes storm restoration expense.

A28. Consistent with the treatment approved in Docket No. 09-414, this adjustment normalizes storm expense using a three year average due to the year-to-year volatility of these costs. By using a normalized level of expenses, the volatility of a particular's test period expense level is mitigated in terms of setting a reasonable level of expense which would be more representative of the rate effective period. This adjustment is detailed on

Schedule (JCZ)-12 and results in a $457,675 increase to test period earnings.

Q29. Please describe Adjustment No. 14, which normalizes recurring IRP costs.

A29. Consistent with treatment approved in the Company's filing in Docket No. 09-414, the Company proposes the normalization of its IRP recurring costs. Although the IRP process represents a 2-year cycle, the costs within the cycle are not ratably incurred each year. Costs include modeling and analytical service, life cycle assessment of power options, outside legal expenses and consultant fees. Schedule (JCZ)-13 summarizes this adjustment, which results in a $342,371 decrease to test period earnings.

Q30. Please describe Adjustment No. 15, which amortizes IRP deferred costs.

A30. Consistent with treatment approved in the Company's filing in Docket No. 09-414, this adjustment reflects the amortization of deferred costs related to the Company's initial IRP. These costs were incurred beginning in August 2009 (the costs approved for recovery in Docket No. 09-414 were incurred by or before July 2009). In terms of cost recovery, Delaware Code Section 1007 (c) (1) d states:

"The costs that DP&L incurs in developing and submitting its IRPs shall be included and recovered in DP&L's distribution rates".

These costs are proposed to be amortized over a 10-year amortization with the unamortized balance included in rate base. This adjustment is detailed on Schedule (JCZ)-14 and reflects a $6,050 decrease to test period earnings and a $57,474 increase to test period rate base.

Q31. Please describe Adjustment No. 16, which amortizes RFP deferred costs.

A31. Consistent with treatment approved in the Company's filing in Docket No. 09-414, this adjustment reflects the amortization of deferred costs related to the Company's RFP (also known as the Bluewater Wind RFP) process. The RFP was part of the initial IRP process under Delaware Code Section 1007 (d) and cost recovery for IRP costs are to be recovered through the Company's distribution rates under Delaware Code Section 1007 (c) (1) d, as previously mentioned. The costs in this adjustment were incurred beginning in August 2009 (the costs approved for recovery in Docket No. 09-414 were incurred by or before July 2009). These costs are proposed to be amortized over a 15-year amortization with the unamortized balance included in rate base. This adjustment is detailed on Schedule (JCZ)-15 and reflects a $3,028 decrease to test period earnings and a $28,764 increase to test period rate base.

AMI, Dynamic Pricing and DLC

Q32. Please describe the status of current of the AMI, Dynamic Pricing and DLC programs.

A32. These programs have been approved by the Commission and are in various stages of deployment. AMI was approved in Order No. 7420 and has been fully deployed to customers. The application for Dynamic Pricing was approved in Order No. 8105 and its initial roll-out to customers started last summer with a Field Acceptance testing group with a roll-out to all Residential Standard Offer Service customers planned for this summer. The DLC program was approved in Order No. 8253 with its roll-out to customers planned to start in the 2nd quarter of 2013 and continuing through 2016. Both Order Nos. 7420 and 8253 granted the Company the ability to establish regulatory assets in regard to the costs of these programs.

Q33. Please describe the current accounting for the AMI, Dynamic Pricing and DLC programs.

A33. The Company has received approvals from the Commission to defer costs related to these programs into regulatory assets. Costs would continue to be deferred until they become part of the Company's normal recurring cost of service upon full deployment or roll-out of these programs. While the AMI assets such as meters, communication equipment and system-related hardware and software were part of the approved rate base in Docket No. 11-528, there are operating costs, as well as operating savings, related to AMI that are still deferred to regulatory assets. They continue to be deferred since the AMI Regulatory Asset Phase-In plan in Docket No. 11-528 addressed the recovery of costs in the regulatory asset and did not set forth a process by which those costs, that would be recurring in nature, would be reflected in test period cost of service on an on-going basis.

In terms of Dynamic Pricing and DLC programs, all of the incremental costs related to them are currently deferred to regulatory assets. As such, there are no operating expenses included in the test period cost of service related to Dynamic Pricing since that program is planned to continue through the rate effective period and beyond. In terms of the DLC program, all costs related to the program for its entirety will be deferred to a regulatory asset with recovery to be done through distribution base rates.

Q34. Please describe the proposed accounting concepts that your ratemaking adjustments will achieve in terms of the AMI, Dynamic Pricing and DLC programs.

A34. The ratemaking adjustments related to these programs share several general concepts, which include:

- Matching of customer benefits and cost recovery, which is a similar concept that was used in the AMI Regulatory Asset Phase-In Plan in Docket No. 11-528.
- During the course of this filing, the other parties will be able to vet the costs and customer benefits related to these programs, just as they have been able to do with the AMI Regulatory Asset Phase-In Plan. In the case of the proposed AMI ratemaking adjustments in this filing, these costs are similar in nature to the ones which have already been reviewed and approved for recovery in the January 1, 2013 AMI Regulatory Asset Phase-In.
- Symmetry for both expenses and savings so that these items are deferred (as they are now) and then included in test period cost of service as expenses (or reductions to expenses) as programs are fully deployed or rolled-out to customers. This proposed change in accounting reflects the fact that these items have or will become part of the Company's operations (and thus part of the Company's recurring O&M expense run rate) as the programs are deployed, which will occur in the same time frame as the start of the rate effective period in this filing.

I will now discuss the various ratemaking adjustments related to AMI, Dynamic Pricing and DLC.

Q35. Please describe Adjustment No. 17, which reflects proforma incremental AMI O&M expenses.

A35. With the full deployment of AMI in the Company's Delaware Electric jurisdiction as well as the Commission-approved AMI Regulatory Asset Phase-In Recovery plan in Docket No. 11-528, the Company proposes to have its AMI-related expenses included in cost of service used to develop its base rates. These costs are currently being deferred into a regulatory asset with recovery of those costs coming through the Phase-In plan. These costs include software maintenance fees, network costs and leases, incremental work force, and consultant costs and are detailed on Schedule (JCZ)-16. If this proposed adjustment were approved, these costs would no longer be deferred as they were during the test period and would be expensed in rate effective period. Schedule (JCZ)-16 summarizes this adjustment, which results in a $1,303,207 decrease to test period earnings.

Q36. Please describe Adjustment No. 18, which reflects proforma incremental AMI O&M Savings.

A36. As part of the Company's AMI Business Case in Docket No. 07-28, the Company projected Energy Delivery benefits from AMI in the form of O&M savings. As shown in Schedule (JCZ)-17, these savings relate to meter reading expense, remote turn-on/turn-off functionality, customer care and other activities. During 2012, the Company credited actual savings achieved to the aggregate AMI regulatory asset balance, thus reducing both the overall regulatory asset balances and the test period cost of service related to these items. These savings are detailed in Schedule (JCZ)-17. The purpose of this adjustment is to reflect in base rates the associated amount of savings related to each benefit, except for remote turn-on and turn-off related to involuntary service terminations and asset optimization as noted below, in terms of the rates reflecting the forecasted business plan savings or the 2012 actual savings.

The majority of the variance between actual savings and those savings forecasted in the business plan is driven by savings related to remote turn-on/turn-off functionality, which includes both customer-requested moves, additions and successions savings as well as involuntary service terminations savings for failure to pay, theft of service and safety violations. The remote turn-on/turn-off functionality was recently implemented for customer-requested moves, additions and successions but it did not create savings that were recorded in the test period.

The first exception for this adjustment relates to remote turn-on and turn-off savings related to involuntary service terminations. The Company's ability to achieve these savings is subject to the approval of a currently pending request to amend the regulations found at Section 3002 of the Delaware Administrative Code, which were promulgated by Order No. 6148, PSC Regulation Docket No. 53, titled "Regulations Governing Termination of Residential Electric or Natural Gas Service by Public Utilities for Non-Payment During Extreme Seasonal Temperature Conditions". Due to this pending request which currently prevents the Company from achieving these forecasted savings, I have not included these involuntary service termination remote turn-off savings in this adjustment; however, I would propose that such savings, when realized, be credited to a regulatory asset.

The second exception relates to asset optimization. This savings primarily relates to the reduction in truck rolls during restoration activities due to the AMI-enabled technology to "ping" a meter to determine if there is an actual outage for a customer. "Pinging" a meter allows the Company to remotely test whether a customer has electric service to his or her premise. If a customer has an outage and the Company is able to determine that there is service to the meter by "pinging" it, the customer may have an issue on his or her side of the meter. In addition, a customer may have a second home that he or she inquires as to whether it still has service. These requests can also be checked remotely using a meter "ping" as opposed to sending a service person in a truck to check. In 2012, there were 1,209 instances in the Delaware electric jurisdiction in which a customer called in regard to a power outage at their premise but by "pinging" the meter, the Company was able to determine that there was service to the customer's meter. Based on those 1,209 meter "pings", the Company was able to avoid truck rolls for them, which allowed those resources to be redeployed to lower the time to restore customers who were actually out of service that the Company needed to address. While the personnel and vehicles involved in the truck rolls were not eliminated, the avoided costs related to them are already reflected in the test period cost of service. Restoration-related labor and vehicle costs were lower than they otherwise would have been if the Company had not "pinged" the meters and avoided unnecessary truck rolls. Based on these facts, there was no asset optimization savings factored into this ratemaking adjustment.

This adjustment incorporates the associated AMI-related savings, except for the remote turn-on and turn-off savings related to involuntary service terminations that will be credited to a regulatory asset once they are realized and the asset optimization, into the cost of service, which would be representative of the savings that are forecasted to be in place for the rate effective period. Similar to Adjustment No. 17, these savings would no longer be deferred to a regulatory asset if this proposed adjustment is accepted. Schedule (JCZ)-17 summarizes this adjustment, which results in an $811,752 increase to test period earnings.

Q37. Please describe Adjustment No. 19, which reflects proforma incremental AMI depreciation and amortization expense.

A37. Similar to the previously-discussed costs and savings related to AMI, incremental AMI depreciation and amortization expenses have been and continue to be deferred to AMI regulatory assets ever since the AMI deployment started. In terms of depreciation expense, the difference between an AMI meter expense and a non-AMI meter expense, which is the amount that customers currently have in their rates, has been deferred. In terms of amortization expense for system-related assets such as the Meter Data Management System and AMI Network Management System that were discussed in the AMI Blueprint Business plan, those expenses have all been deferred up to now despite being used and useful. With AMI being fully deployed, the proposed adjustment would charge these items to expense in the Company's cost of service and thus stop the need to defer these costs to a regulatory asset. Schedule (JCZ)-18 summarizes this adjustment, which results in a $1,662,531 decrease to test period operating income.

Q38. Please describe Adjustment No. 20, which amortizes the Dynamic Pricing regulatory asset.

A38. In Order No. 8105 related to Docket No. 09-311, the Commission approved the Company's application to implement dynamic pricing that would enable customers across the state to take greater control of their electricity usage by providing a simple automated method by which customers can reduce consumption during certain peak periods. The AMI deployment, approved in Order No. 7420, provides the technology to enable dynamic pricing to be implemented. Similar to the start-up and program costs related to AMI, the costs related to the dynamic pricing program were deferred to a regulatory asset for future recovery purposes based on Order No. 7420. With Dynamic Pricing offered to a group of 6,904 Field Acceptance Test participants in the summer of 2012 and a planned roll-out to all of the Company's Standard Offer Service residential customers in the summer of 2013, the Company proposes that it start to recover those costs as part of this filing. The dynamic pricing program deferred costs will continue to be incurred prior to the start of the rate effective period. In addition, customers will already have the opportunity to partake in the benefits of the program prior to the start of the rate effective period. Based on the timing of these customer benefits, the Company proposes a 15-year amortization, similar to the approved amortization period of AMI regulatory assets in Docket No. 09-414, with the unamortized balance receiving rate base treatment.

The proposed recovery amount would include both the currently deferred dynamic pricing costs of $2,976,459 as of February 2013, as well as $3,723,028 of projected deferred costs until the start of the rate effective period (November 2013). As detailed on Schedule (JCZ)-19, the costs include items such as customer education, outbound calls for Dynamic pricing events and costs for overflow customer call handling related to those events as well as amortization related to Dynamic-related systems. Schedule (JCZ)-19 also summarizes this adjustment, which results in a $265,054 decrease to test period earnings and a $3,843,284 increase in test period rate base.

Q39. Please describe Adjustment No. 21, which reflects proforma incremental Dynamic Pricing O&M expenses.

A39. With the full roll-out of the Company's Dynamic Pricing program to Delaware Electric residential customers planned for this summer, the Company proposes to have its recurring annual Dynamic Pricing-related expenses included in cost of service used to develop its base rates. Otherwise, these costs would be deferred into a regulatory asset with recovery of those costs coming at some later date. These costs include the outbound calls to customers for dynamic pricing events and costs for overflow customer call handling related to those events as well as related the information technology systems support. If this proposed adjustment were approved, these costs would no longer need to be deferred. Schedule (JCZ)-20 summarizes this adjustment, which results in a $445,258 decrease to test period earnings.

Q40. Please describe Adjustment No. 22, which reflects proforma incremental Dynamic Pricing amortization expenses.

A40. Similar to the reasons cited for the proposed inclusion in cost of service for the Company's Dynamic Pricing-related recurring incremental O&M expense, the Company also proposed the inclusion of incremental Dynamic Pricing amortization expense. Otherwise, these costs would be deferred into a regulatory asset with recovery of those costs coming at some later date. These costs include the amortization of both the dynamic pricing portion of the Meter Data Management System software as well as the dynamic pricing interfaces with the customer information system. This adjustment is detailed on Schedule (JCZ)-21 and results in a $733,262 decrease to test period earnings.

Q41. Please describe Adjustment No. 23, which amortizes the Direct Load Control regulatory asset.

A41. In Order No. 8253 related to Docket No. 11-330, the Commission granted the Company the authority to establish a residential air conditioning cycling program as well as its Residential Direct Load Control rider. As part of its report filed in Docket No. 11-330, Commission Staff supported Delmarva's request that it be permitted to create a regulatory asset to recover the filed costs of the program ($25,477,246) with the carrying cost set at the current weighted cost of capital. In Order No. 8253, the Commission confirmed the establishment of a Direct Load Control regulatory asset by stating:

That the Commission confirms that the language of Order No. 7420, in which the Commission "permit[ted] Delmarva to establish a regulatory asset to cover recovery of and *on the appropriate operating costs associated with the deployment of Advanced Metering Infrastructure and demand response equipment," authorized Delmarva to establish a regulatory asset for costs incurred in implementing and monitoring the Cycling Program.*

Implementation of the Company's Direct Load Control program started late in 2012 and will continue through 2016 as shown in Schedule (JCZ)-22. 19,600 of the total 51,600 projected participating customers are forecasted to have their Direct Load Control switch and thermostat installed at their residences by the end of December 2013. During that period, $9,803,140 of the projected total program costs ($25,456,692) will be incurred with customers able to partake in the benefits of the program within that time frame.

The Company proposes a 15-year recovery of this regulatory asset, similar to the period approved for AMI regulatory assets in Docket No. 09-414, with the unamortized balance receiving rate base treatment. These projected costs would be updated for actual costs during the course of this proceeding. This proposal achieves a matching of allowing recovery of actual incurred costs to accompany benefits received by customers. Schedule (JCZ)-22 summarizes this adjustment, which results in a $393,571 decrease to test period operating income and a $5,706,782 increase in test period rate base.

Q42. Please describe Adjustment No. 24, which annualizes depreciation expense on year-end plant in service.

A42. The adjustment compares the 12 months ending December 2012 test year amount of depreciation expense to an annualized level of depreciation expense amount based on the year ended December 2012 plant assets, using the Commission-approved depreciation rates. In addition, an adjustment is included to the accumulated depreciation reserve to recognize the difference in annualized depreciation expense to the test period level of depreciation expense. My proposed adjustment to rate base and operating income is shown on Schedule (JCZ)-23 and results in a $213,425 decrease to test period earnings and a $213,425 decrease to test period rate base.

Q43. Please describe Adjustment No. 25, which normalizes other taxes.

A43. This adjustment relates to a non-recurring expense in the test period cost of service. Included in the Company's Other Taxes was a credit of $188,971, which represented a reversal of an accrual related to 2009 Delaware franchise taxes. Since this item is not representative of the level of Other Taxes expected in the rate effective period, this amount is removed from cost of service. This adjustment is detailed on Schedule (JCZ)-24 and results in a decrease to test period earnings of $112,545.

Q44. Please describe Adjustment No. 26, which reflects proforma forecasted reliability plant project closings from January 2013 through December 2013.

A44. As approved by the Commission in Docket Nos. 05-304 and 09-414, this adjustment reflects the annualization of reliability plant added to Plant in Service beyond the end of the test period. The actual reliability plant additions should be included in rate base to properly synchronize the value that customers will realize during the rate effective period to the amount included in rates. As previously mentioned, the Commission approved this concept in its decision in Order No. 8011 relating to Docket No. 8011, when it stated:

*60. **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).*

I have included forecasted reliability plant closings through December 2013. This adjustment also reflects the annualization of any forecasted retirements to plant associated with this period. This adjustment is detailed on Schedule (JCZ)-25 and results in a decrease to test period earnings of $1,088,493 and an increase to test period rate base of $66,794,140.

Q45. Please describe Adjustment No. 27, which amortizes actual refinancing transactions.

A45. Consistent with the approved ratemaking treatment that has been included in prior Commission decisions, in Docket No. 86-24 through Docket No. 09-414, I have included in this filing the earnings and rate base treatment of refinancings that was allocated to the Electric business. Lower cost rates in the Company's capital structure resulting from the Company's refinancings provide a benefit to customers. This adjustment is detailed on Schedule (JCZ)-26 and reflects a $370,828 decrease to test period earnings and a $2,976,401 increase to test period rate base.

Q46. Please describe Adjustment No. 28, which removes Qualified Fuel Cell Provider costs.

A46. The Company proposes the removal of Bloom-related costs that are currently included as expense in test period cost of service as those costs would be recovered through the Fuel Cell Provider tariff, not base rates. This adjustment is detailed on Schedule (JCZ)-27 and results in an $84,783 increase to test period earnings.

Q47. Please describe Adjustment No. 29, which amortizes deferred taxes related to Medicare subsidy costs.

A47. Similar to the adjustment proposed in Docket No. 11-528, this adjustment proposes recovery of additional taxes related to a change in the law regarding Medicare Part D. The Patient Protection and Affordable Care Act, which became law in March 2010, resulted in a deferred tax charge to the Company's Federal income tax expense. The law changes the tax treatment of federal subsidies paid to the Company to offset the costs for certain retiree health benefits. The charge to tax expense was deferred in the financial records of the Company. The Company proposes to recover these deferred costs over a three-year period. This adjustment is shown on Schedule (JCZ)-28 and results in a $21,860 decrease to test period earnings as well as a $54,650 increase to test period rate base.

Q48. Please describe Adjustment No. 30, which removes Post-1980 ITC amortization.

A48. Consistent with the approved ratemaking treatment in previous cases including the most recent proceeding, Docket No. 09-414, this adjustment removes post-1980 vintage ITC amortizations. This adjustment reflects the requirements of the Economic Recovery Tax Act of 1981 (ERTA) on post-1980 vintage projects for rate case purposes. The Company has been amortizing ITC on a property service life basis. Under ERTA, Delmarva is an Option One Company for ratemaking purposes for post-1980 vintages. The related ratemaking treatment is to deduct the post-1980 accumulated unamortized balance from rate base, and at the same time, not include the related post-1980 vintage amortizations as a reduction of operating expenses. This adjustment is detailed on Schedule (JCZ)-29 as a $255,733 decrease to test period earnings.

Q49. Please describe Adjustment No. 31, which recovers credit facilities expense.

A49. Consistent with ratemaking treatment approved in the Company's filing in Docket No. 09-414, this adjustment reflects the Company's cost related to the PHI credit facility. PHI's credit facility is vital for serving the day-to-day cash needs of its companies, such as Delmarva. 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 and thus would not otherwise be recovered. On August 1, 2011, PHI renewed its credit facility for a five-year term. As shown in Schedule (JCZ)-30, the costs related to the current credit facility are reflected and the related adjustment results in a $200,057 decrease to test period earnings as well as a $520,111 increase to test period rate base.

Q50. Please describe Adjustment No. 32, which removes Renewable Portfolio Standard labor costs.

A50. Included in the Distribution test period cost of service were expenses related to the RPS process. These costs were recovered through the Qualified Fuel Cell Provider tariff and thus should be removed from the cost of service in this filing to prevent an over-recovery. This adjustment is detailed on Schedule (JCZ)-31 and results in a $41,136 increase to test period earnings.

Q51. Please describe the Interest Synchronization and Cash Working Capital Adjustments that you support in this proceeding, Adjustments No. 33 and 34.

A51. This adjustment, shown on Schedule (JCZ)-30, synchronizes the interest expense utilized in the per books income tax calculation with the adjusted rate base and the tax deductible component included in the cost of capital. Schedule (JCZ)-30 also displays the change in cash working capital associated with the proforma adjustments.

Q52. Do the Company's proposed rate base and earnings conform to the Commission's last detailed decision, Docket No. 09-414?

A52. Yes, although there are three items that differ from the Commission's decision in Docket No. 09-414. The Commission did not include CWIP in rate base but indicated that it was within its discretion in future cases to determine whether CWIP should be included in rate base. I have included CWIP in rate base with the corresponding accrued AFUDC in earnings.

The Commission approved the use of average, not year-end, rate base in the development of the overall revenue requirement.

Also, the Commission denied the inclusion of non-executive incentive expense in Docket No. 09-414 on the basis that the amount had not been clearly defined during the proceeding.

In the following section, I address the Company's position on these items, which differ from the Commission's decision in Docket No. 09-414.

CWIP and AFUDC

Q53. Why do you propose including CWIP and AFUDC in the Company's cost of service?

A53. Distribution projects are made up of thousands of work requests (WR) 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. The majority of these WR are characterized as having short construction durations and, on a per unit basis, a low cost when compared to major plant additions such as a new substation. The Company follows the appropriate procedure for accruing AFUDC at the WR level. Due to the fact that many WRs do not exceed the minimum threshold for accruing AFUDC, many of these distribution projects accrue no AFUDC and the majority of projects that do, accrue AFUDC for only a few months.

These new assets are placed into service throughout a given month but only close to plant in service on a monthly 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 include direct purchases and projects of short duration and lower value. It is appropriate to afford rate base treatment to these projects which are now either in service, serving customers with known and measurable costs or will very soon be in service, serving customers with known and measurable costs.

Q54. What is the effect on the Company if the Commission does not allow the Company to recover the carrying cost of dollars in CWIP that are not accruing AFUDC?

A54. The Company inappropriately bears the burden of those carrying costs. It is unfair that the Company would spend dollars on investment that will provide service to its customers but not be compensated for funding those investments. The Company should be compensated for the cost associated with that expenditure.

Q55. Do you propose an alternative in this proceeding if CWIP and AFUDC are not included in cost of service?

A55. Yes, I do. I understand that all of the parties are concerned with the relatively low effective AFUDC rate discussed by the Commission. If the Commission were to decide not to include CWIP and the associated accrued AFUDC in cost of service, there is a reasonable alternative. The Company could record a carrying cost on all CWIP. The difference between the actual accrued, recorded AFUDC and the full calculated carrying cost would be recorded as a regulatory asset. This regulatory asset would be treated in the Company's next case just as if it had been actually accrued AFUDC; that AFUDC would be amortized over an assigned life and included in rate base just as if had been capitalized.

Q56. When do you propose that the calculation of this "Full AFUDC" would begin?

A56. 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 to accumulate at the end of the test period used in the Company's next proceeding.

<u>Year-End Rate Base</u>

Q57. Please explain your proposed treatment of year-end rate base.

A57. I propose the use of year-end, not average, rate base as the year-end rate base better reflects the assets which will be serving customers during the rate effective period for which rates in this proceeding are being established. I have included Adjustment No. 23 to annualize depreciation expense based on year-end rate base to ensure a proper matching or rate base and expense.

Q58. Do other PHI utilities use year-end rate base for the development of their revenue requirement?

A58. Yes. Atlantic City Electric uses year-end rate base in its revenue requirement calculations in New Jersey.

Non-Executive Incentive Compensation

Q59. Please explain your proposed treatment of Non-Executive Incentive Compensation.

A59. I propose the inclusion of the test period level of non-executive incentive compensation in the Company's cost of service for this filing. In Docket No. 09-414, the Commission did not include the expense associated with non-executive incentives in cost of service because there was a concern whether the detail associated with the components related to safety, reliability and similar goals was entered into the record of the proceeding. The Commission, in its deliberation, discussed being consistent with its decision in the 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.

Q60. What has the Commission stated previously about incentive programs?

A60. While the Commission has previously excluded the inclusion of incentive compensation payments that are primarily triggered by the achievement of financial triggers, the Commission has allowed incentives that are triggered by the achievement of safety, reliability and similar goals. The Commission's Order in Docket No. 05-304 discussed that this was a difficult issue for the Commission and they recognized that they have allowed payments made under incentive plans to be included in rates in the past. The Commission has stated that such programs benefit ratepayers by extending the period between rate cases.

The non-executive incentives included in the test period are a part of the total compensation package paid to employees and such programs benefit customers by extending the period between rate cases. The Company's performance incentive plans are part of employees' total compensation package. While base salaries could be increased to reflect a higher level of compensation in lieu of incentives, having an at-risk portion of compensation available is widely used to motivate employees to be more efficient and productive. For Delmarva Power, this program helps to focus employees' attention and efforts on achieving the Company's goals. Many of these goals are explicitly related to safety and customers and to the extent that other goals are financial in nature, such goals help motivate employees to keep costs down and thus will benefit customers in the ratemaking process.

While the specifics of the annual incentive program differ from area to area, or among levels, they all have the same framework of drivers. In particular, all of the programs have an employee measure such, as safety. All of the programs also have a customer satisfaction component as well as a reliability measure. Finally, the programs all have financial components such as O&M expense control, managing capital expenditures and achieving our net income targets overall, which, if achieved, lower the revenue requirements to customers and will extend time between base rate filings.

All three of these areas work in concert – motivated employees looking out for the safety of themselves and the public, serving the needs and expectations of satisfied customers, and doing so in a financially responsible way. These incentives motivate employees to work safely, promote efficiency and focus on critical processes such as diversity, reliability and our customers' needs.

For these reasons I have not removed the non-executive incentive expense. I feel that all of the goals, including the financial triggered goals, should be included in rates.

Q61. Can you quantify the Non-Executive Incentive Expense that is included in the Company's filed test period?

A61. Yes, I can. For the test period used in this filing, the non-executive incentives total $1,993,801 for the Delaware jurisdiction and of this total, $1,196,280 is related to customer satisfaction and reliability ($797,520), safety ($199,380), Affirmative Action ($99,690) and Regulatory and Compliance ($99,690).

Q62. What is your proposed treatment of Non-Executive Incentive expense?

A62. I propose that all non-executive incentive expense be included in the final cost of service approved by the Commission in this proceeding. A key part of the total compensation paid to employees is these incentives, which aid in the motivation of employees to work safely, promote efficiency and focus on critical processes such as diversity, reliability and our customers' needs.

OVERALL REVENUE REQUIREMENT

Q63. Can you summarize the adjustments that are included in this filing?

A63. Yes, I can. Schedule (JCZ)-1, Page 2 displays all of the proforma adjustments included in this filing and the earnings and rate base impact.

Q64. Has the Company been earning less than its authorized return on equity?

A64. Yes. A review of the return on equity for the last six calendar years on an unadjusted basis shows that the Company is not earning its authorized return. The unadjusted return on equity as presented from the Company's annual rate of return reports for the past five years is as follows on the next page:

Table 1

Year	Earned ROE	Authorized ROE	Rev Deficiency (Excess) Millions
2008	9.26%	10.00%	$2.6
2009	5.11%	10.00%	$17.0
2010	8.23%	10.00%	$7.2
2011	4.78%	10.00%	$25.1
2012	5.59%	9.75%	$23.8

As noted in Company Witness Boyle's Direct Testimony, the Company will only earn 5.59% return on equity after annualizing the rate increase authorized by the Commission in Docket No. 11-528. Although the 2012 annual rate of return report has not yet been filed, the annualization of the rate increase is shown as Adjustment No. 1 in Schedule (JCZ)-1, Page 2 and is added to the unadjusted per books amounts shown on the same schedule to derive the 5.59% return on equity.

Q65. Please summarize the Company's overall revenue deficiency.

A65. Schedule (JCZ)-2 displays the calculation of the Company's revenue deficiency of $42,034,757. This calculation includes the effect of all of the proforma adjustments to the test period level of earnings and rate base and uses the Direct Testimony of Company Witness Boyle's supplied rate of return of 7.53%.

Q66. Does this conclude your Direct Testimony?

A66. Yes, it does.

Delmarva Power & Light Company
Delaware Distribution Rate of Return
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) Total Distribution	(5) Delaware Distribution
1	**Rate Base**			
2	Electric Plant in Service	$ 2,783,726,241	$ 1,889,066,349	$ 1,106,124,352
3	Less: Depreciation Reserve	$ 1,012,029,810	$ 697,550,214	$ 408,440,153
4	Net Plant in Service	$ 1,771,696,431	$ 1,191,516,135	$ 697,684,198
5				
6	CWIP	$ 207,030,424	$ 112,024,855	$ 70,154,772
7	Working Capital	$ 20,410,066	$ 20,410,066	$ 10,887,807
8	Plant Materials & Supplies	$ 38,417,359	$ 31,005,440	$ 18,164,174
9	Plant Held For Future Use	$ 2,578,570	$ 2,578,570	$ -
10	Prepaid Balances	$ 102,243,025	$ 95,177,212	$ 57,392,849
11	Deferred Federal and State Tax Balance	$ (577,227,011)	$ (278,119,582)	$ (162,161,551)
12	Deferred Investment Tax Credit	$ (4,841,754)	$ (2,816,294)	$ (1,853,616)
13	Customer Deposits	$ (22,285,152)	$ (22,285,152)	$ (13,702,572)
14	Customer Advances	$ (3,681,013)	$ (3,681,013)	$ (1,651,163)
15				
16	Total Rate Base	$ 1,534,340,946	$ 1,145,810,238	$ 674,914,898
17				
18	**Earnings**			
19	Operating Revenues	$ 1,045,695,062	$ 325,550,913	$ 176,519,552
20				
21	O & M Expense	$ 788,856,125	$ 184,270,618	$ 103,201,264
22	Depreciation and Amortization Expense	$ 77,012,781	$ 52,050,353	$ 28,293,088
23	Taxes Other than Income Taxes	$ 31,560,930	$ 20,007,394	$ 7,973,607
24	Deferred FIT Expense	$ 36,840,439	$ 35,038,003	$ 20,457,413
25	Deferred SIT Expense	$ 9,847,314	$ 9,287,751	$ 5,569,692
26	Net ITC Adjustment	$ (620,781)	$ (431,699)	$ (250,890)
27	State Income Tax	$ (675,003)	$ (5,609,340)	$ (3,801,179)
28	Federal Income Tax	$ (3,731,997)	$ (21,433,473)	$ (13,961,686)
29	Total Operating Expenses	$ 939,089,809	$ 273,179,607	$ 147,481,308
30				
31	Operating Income	$ 106,605,253	$ 52,371,306	$ 29,038,244
32				
33	AFUDC	$ 4,526,603	$ 1,574,198	$ 965,309
34	Misc Earnings Items	$ (24,326)	$ (24,326)	$ (14,967)
35	Earnings	$ 111,107,530	$ 53,921,177	$ 29,988,586

Delmarva Power & Light Company
Delaware Electric Distribution Adjustments
12 Months Ending December 2012

(1) Line No.		(2) Item	(3) Witness	(4) Earnings	(5) Rate Base	(6) ROR	(7) ROE	(8) Revenue Requirement
1	**Per Books Unadjusted**			$29,988,586	$674,914,898	4.44%	3.96%	$35,541,505
2								
3	**Adjustments:**							
4	1	Rate Change from Docket No. 11-528	Santacecilia	$5,643,025	$0			($9,627,340)
5	2	Weather Normalization	Santacecilia	$163,716	$0			($279,309)
6	3	Bill Frequency	Santacecilia	$1,227,683	$0			($2,094,500)
7	4	Year End Customers	Santacecilia	$424,587	$0			($724,371)
8	5	Regulatory Commission Exp Normalization	Ziminsky	($85,345)	$0			$145,603
9	6	Injuries and Damages Exp Normalization	Ziminsky	$25,878	$0			($44,149)
10	7	Uncollectible Expense Normalization	Ziminsky	$93,186	$0			($158,981)
11	8	Wage and FICA Expense	Ziminsky	($1,114,374)	$0			$1,901,189
12	9	Remove Employee Association Expense	Ziminsky	$53,123	$0			($90,631)
13	10	Proform Benefits Expense	Ziminsky	($318,199)	$0			$542,867
14	11	Removal of Executive Incentive Compensation	Ziminsky	$1,291,130	$0			($2,202,745)
15	12	Removal of Certain Executive/Officer Compensation	Ziminsky	$23,393	$0			($39,911)
16	13	Storm Restoration Expense Normalization	Ziminsky	$457,675	$0			($780,821)
17	14	Reflect IRP Recurring Expense	Ziminsky	($342,371)	$0			$584,105
18	15	Amortize IRP Deferred Costs	Ziminsky	($6,050)	$57,474			$17,705
19	16	Amortize RFP Deferred Costs	Ziminsky	($3,028)	$28,764			$8,861
20	17	Proform AMI O&M Expenses	Ziminsky	($1,303,207)	$0			$2,223,349
21	18	Proform AMI O&M Savings	Ziminsky	$811,752	$0			($1,384,897)
22	19	Proform AMI Depreciation & Amortization Expense	Ziminsky	($1,662,531)	$0			$2,836,378
23	20	Amortize Dynamic Pricing Regulatory Asset	Ziminsky	($265,054)	$3,843,284			$945,931
24	21	Proform Dynamic Pricing O&M Expenses	Ziminsky	($445,258)	$0			$759,638
25	22	Proform Dynamic Pricing Amortization Expense	Ziminsky	($733,262)	$0			$1,250,989
26	23	Amortize Direct Load Control Regulatory Asset	Ziminsky	($393,571)	$5,706,782			$1,404,585
27	24	Annualization of Depreciation on Year-end Plant	Ziminsky	($213,425)	($213,425)			$336,698
28	25	Normalize Other Taxes	Ziminsky	($112,145)	$0			$191,326
29	26	Proform Forecasted Reliability Closings January 13 - December 2013	Ziminsky/Maxwell	($1,088,493)	$66,794,140			$10,437,832
30	27	Amortization of Actual Refinancing Costs	Ziminsky	($370,828)	$2,976,401			$1,015,022
31	28	Remove Qualified Fuel Cell Provider Project Costs	Ziminsky	$84,783	$0			($144,645)
32	29	Amortize Medicare Subsidy Deferred Costs	Ziminsky	($21,860)	$54,650			$44,315
33	30	Remove Post-80 ITC Amortization	Ziminsky	($255,733)	$0			$436,295
34	31	Recover Credit Facilities Expense	Ziminsky	($200,057)	$520,111			$408,125
35	32	Removal of RPS Labor Charges	Ziminsky	$41,136	$0			($70,181)
36	33	Interest Synchronization	Ziminsky	$790,792	$0			($1,349,138)
37	34	Cash Working Capital	Ziminsky	$0	$23,798			$3,057
38								
39		**Adjusted Total**		$32,185,654	$754,706,877	4.26%	3.60%	$42,043,757

Schedule (JCZ)-2

Delmarva Power & Light Company
Delaware Distribution
12 Months Ending December 2012 Test Period
Determination of Revenue Requirements

(1) Line No.	(2) Item	(3) Detail
1	Adjusted Net Rate Base	$754,706,877
2	Required Rate of Return	7.53%
3	Required Operating Income	$56,829,428
4	Pro Forma Operating Income	$32,185,654
5	Operating Income Deficiency	$24,643,774
6	Revenue Conversion Factor	1.70606
7	Revenue Requirement	$42,043,757

Schedule (JCZ)-3

Delmarva Power & Light Company
Distribution Cash Working Capital
12 Months Ending December 2012

(1) Line No.	(2) ITEM	(3) Distribution Amount	(4) Revenue Lag	(5) (Lead)/Lag Days	(6) Net Lag Days	(7) % 365 DAYS	(8) Distribution CWC	(9) DE Distribution %	(10) DE Distribution CWC
1	**O&M**								
2	O & M	$184,270,618	52.14	17.33	34.81	9.54%	$17,573,864	57.88%	$10,172,262
3	**Total O & M**	**$184,270,618**					**$17,573,864**		**$10,172,262**
4									
5	**Other Taxes**								
6	Taxes Other Than Income Taxes								
7	Delaware Public Utility Tax	$5,776,550	52.14	35.88	16.26	4.45%	$257,333	100.00%	$257,333
8	DE Franchise Tax	($133,928)	52.14	137.78	(85.64)	-23.46%	$31,423	100.00%	$31,423
9	MD Franchise Tax	$5,796,428	52.14	38.51	13.63	3.73%	$216,453	0.00%	$0
10	Delaware Local Tax	$188,862	52.14	(40.56)	92.70	25.40%	$47,966	100.00%	$47,966
11	Maryland Local Tax	$682,382	52.14	35.26	16.88	4.62%	$31,558	0.00%	$0
12	Total - Revenue Taxes	**$12,310,295**					**$584,734**		**$336,723**
13									
14	Property Tax								
15	Property Tax	$10,899,998	52.14	(91.12)	143.26	39.25%	$4,278,174	58.58%	$2,506,318
16	Total Property Taxes	**$10,899,998**					**$4,278,174**		**$2,506,318**
17									
18	Payroll Tax								
19	FICA	$2,381,670	52.14	12.03	40.11	10.99%	$261,723	58.58%	$153,327
20	FUTA/SUTA	$154,971	52.14	76.38	(24.24)	-6.64%	($10,292)	58.58%	($6,029)
21	Total Payroll	**$2,536,641**					**$251,431**		**$147,298**
22									
23	**Total Other Taxes**	**$25,746,933**				19.86%	**$5,114,339**		**$2,990,339**
24									
25	**Income Taxes**								
26	State	($3,801,179)	52.14	(17.30)	69.44	19.02%	($723,161)	100.00%	($723,161)
27	Federal	($13,961,686)	52.14	58.95	(6.81)	-1.87%	$260,491	100.00%	$260,491
28	Total Taxes	**($17,762,865)**					**($462,671)**		**($462,671)**
29									
30	**Interest Expense**	$16,862,023	52.14	91.25	(39.11)	-10.72%	($1,806,777)	100.00%	($1,806,777)
31	**Interest on Customer Deposits**	$24,326	52.14	182.50	(130.36)	-35.72%	($8,688)	61.53%	($5,345)
32	Total Other Items	$16,886,349					($1,815,465)		($1,812,123)
33									
34									
35	**TOTAL CWC**	**$209,141,035**					**$20,410,066**		**$10,887,807**

Schedule (JCZ)-4
Adjustment 5

Delmarva Power & Light Company
Delaware Distribution
Regulatory Commission Expense
12 Months Ending December 2012

(1) Line No.	(2) Item		(3) Delaware Distribution	
1	Non - Rate Case Regulatory Commission Expense			
2	(3 Year Average)		$53,316	(1)
3				
4	Non - Rate Case Regulatory Commission Expense			
5	Included in Test Period:		$48,926	
6				
7	Adjustment to Per Books to normalize non-base case			
8	Regulatory Commission Expense		$4,390	
9				
10	Cost of Current Case (2)	$632,600		
11	Amount included in Adjustment		$210,867	
12				
13	Total Normalized Expense Adjustment		$215,257	
14				
15	Remove Rate Case Expense from Per Books		($71,446)	
16				
17	Total Regulatory Commission Expense Adjustment		$143,811	
18				
19	SIT		($12,512)	
20	FIT		($45,955)	
21	Net Expense		$85,345	
22				
23	Earnings		($85,345)	

(1) Basis for Normalized Expense

12 m/e 12/31/10	$43,010
12 m/e 12/31/11	$68,013
12 m/e 12/31/12	$48,926
Average	$53,316

(2) Cost of Current Case

External Legal	$315,000
Cost of Capital Witness	$92,600
Court reporter/notice/etc	$25,000
DPSC	$200,000
Total	$632,600

Schedule (JCZ)-5
Adjustment 6

Delmarva Power & Light Company
Delaware Distribution
Normalization of Injuries & Damages Expense
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Detail
1	System Electric Injuries & Damages Expense	
2	(3 Year Average)	$1,242,856 (1)
3		
4	System Electric Injuries & Damages Expense	
5	Included in Test Period:	$1,323,053
6		
7	Adjustment to Per Books	
8	Injuries & Damages Expense	($80,197)
9		
10	Delaware Distribution Allocation	54.37%
11		
12	Delaware Distribution O&M Expense	($43,605)
13		
14	SIT	$3,794
15	FIT	$13,934
16		
17	Net Expense	($25,878)
18		
19	Earnings	$25,878

(1) System Electric

12 m/e 12/31/10	$2,496,765
12 m/e 12/31/11	($91,250)
12 m/e 12/31/12	$1,323,053
Average	$1,242,856

Schedule (JCZ)-6
Adjustment 7

Delmarva Power & Light Company
Delaware Distribution
Normalization of Uncollectible Expense
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Delaware Electric	
1	Delaware Electric Uncollectible Expense		
2	(3 Year Average):	$1,444,777	(1)
3			
4	Delaware Electric Uncollectible Expense		
5	Included in Test Period (non-SOS):	$1,601,802	(1)
6			
7	Adjustment to Per Books Uncollectible Expense	($157,025)	
8			
9	SIT	$13,661	
10	FIT	$50,177	
11			
12	Net Expense	($93,186)	
13			
14	Earnings	$93,186	

(1) Delaware Electric - non-SOS

12 m/e 12/31/10	$1,486,359
12 m/e 12/31/11	$1,246,170
12 m/e 12/31/12	$1,601,802
3 Year Average	$1,444,777

Schedule (JCZ)-7
Adjustment 8

Delmarva Power & Light Company
Delaware Distribution
Wage, Salary, and FICA Expense Adjustment
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Electric
1	**Salary and Wage Adjustment**	
2	Electric Distribution O&M Expense Adjustment	$3,041,858
3		
4	Delaware Distribution	58.58%
5		
6	Delaware Distribution Expense	$1,782,036
7		
8	State Income Tax	($155,037)
9	Federal Income Tax	($569,450)
10	Total Expense	$1,057,549
11		
12	Earnings	($1,057,549)
13		
14		
15	**FICA Adjustment**	
16	Electric Distribution O&M Expense Adjustment	$163,447
17		
18	Delaware Distribution	58.58%
19		
20	Delaware Distribution Expense	$95,753
21		
22	State Income Tax	($8,331)
23	Federal Income Tax	($30,598)
24	Total Expense	$56,825
25		
26	Earnings	($56,825)
27		
28	Total Earnings Adjustment	($1,114,374)

Schedule (JCZ)-8
Adjustment 9

Delmarva Power & Light
Delaware Distribution
Employee Association Expenses
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) $
1	Employee Association expense - total DPL	$184,251
2		
3	Delmarva Power & Light Electric allocation	82.93%
4		
5	Employee Association expenses - DPL Electric	$152,799
6		
7	Delaware Distribution Allocation	58.58%
8		
9	Impact to Operating Expense	($89,515)
10		
11	Impact to SIT @ 8.7%	$7,788
12		
13	Impact to FIT @ 35%	$28,605
14		
15	Impact to Operating Income	$53,123

Schedule (JCZ)-9
Adjustment 10

Delmarva Power & Light Company
Delaware Distribution
Proform Benefits Expense
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Delmarva	(4) 12 m/e December 2012 Service Company	(5) Total	(6) Delmarva	(7) Proforma Service Company	(8) Total	(9) Adjustment
1	Medical	$9,452,411	$5,213,617	$14,666,028	$10,586,700	$5,839,251	$16,425,951	
2	Dental	$822,020	$453,077	$1,275,097	$883,672	$487,058	$1,370,729	
3	Vision	$315,927	$174,197	$490,124	$339,622	$187,262	$526,883	
4								
5	Total	$10,590,358	$5,840,891	$16,431,249	$11,809,993	$6,513,571	$18,323,564	
6								
7	DPL Electric Ratio	100%	82.93%		100%	82.93%		
8								
9	DPL Electric Amount	$10,590,358	$4,843,851	$15,434,209	$11,809,993	$5,401,704	$17,211,697	
10								
11	Expense Ratio	40.28%	88.71%		40.28%	88.71%		
12								
13	O&M Amount	$4,265,510	$4,297,169	$8,562,679	$4,756,746	$4,792,062	$9,548,809	
14								
15	Distribution Ratio			92.81%			92.81%	
16								
17	System Distribution Amount			$7,947,177			$8,862,421	
18								
19	DE Distribution Factor			58.58%			58.58%	
20								
21	DE Distribution Benefit			$4,655,758			$5,191,943	
22								
23	Change in DE Distribution Benefit							$536,185
24								
25	State Income Tax							($46,648)
26	Federal Income Tax							($171,338)
27								
28	Expense							$318,199
29								
30	Impact on Earnings							($318,199)

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

February 18, 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 first quarter of 2013. This represents the projected trends in use for the first 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 three of the seven categories showed a change from the mean average projected fourth quarter 2012 trends. POS and Dental each showed a decrease of 0.1%. Pharmacy showed a decrease of 0.2%.
- When compared to last quarter, three of the six companies made changes to their projected trends. One company decreased HMO and POS 0.4%. Another company decreased dental 0.5%. A third company increased HMO and PPO 0.1%, increased POS 0.2% and decreased Pharmacy 1.2%.
- The HMO first quarter 2013 mean average trend shows no change in the trend from fourth quarter 2012. One company increased this trend 0.1%, and another company decreased it 0.4%. All other companies left this trend unchanged.
- The POS first quarter 2013 mean average trend shows a 0.1% decrease from this trend for fourth quarter 2012. One company increased this trend 0.2%, and another company decreased it 0.4%. All other companies left this trend unchanged.
- The PPO first quarter 2013 mean average trend shows no change from this trend for fourth quarter 2012. One company increased this trend 0.1%. All other companies left this trend unchanged.
- The Indemnity first quarter 2013 mean average trend shows no change from this trend for fourth quarter 2012. All five companies with Indemnity business left their trends unchanged.
- The Dental first quarter 2013 mean average trend shows a 0.1% decrease from this trend for fourth quarter 2012. One company decreased their dental trend 0.5%. All other companies left this trend unchanged.

- The Pharmacy first quarter 2013 mean average trend shows a 0.2% decrease from this trend for fourth quarter 2012. One company decreased it 1.2%. All other companies left this trend unchanged.
- The Consumer Driven Health Plan first quarter 2013 mean average trend shows no change from this trend from fourth quarter 2012. One company increased this trend 0.1%. All other companies left this trend unchanged.
- In the first quarter 2013 trend survey, one company reported CDHP Pharmacy trend (7.3%) being different from the trend for CDHP base plans (5.7%).

This quarter, the mean average projected CDHP trend is the lowest medical trend at 8.9% with trends ranging from 5.7% to 12.0%. POS has the next lowest trend at 9.3% with trends ranging from 7.1% to 12.0%. HMO has the next lowest trend at 9.4% with trends ranging from 7.9% to 12.0%. The PPO trend is the next lowest at 9.6% with trends ranging from 7.7% to 12.0%. 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 12.0%.

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-six 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 9.4%.
- The mean average of POS trends has increased from 6.6% to 9.3%.
- The mean average of PPO trends has increased from 9.3% to 9.6%.
- 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 the same at 8.9%.

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

Sincerely,

Gary D. Lake, FSA

Gary D. Lake, FSA
Consulting Actuary

Jon R. Jennings

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

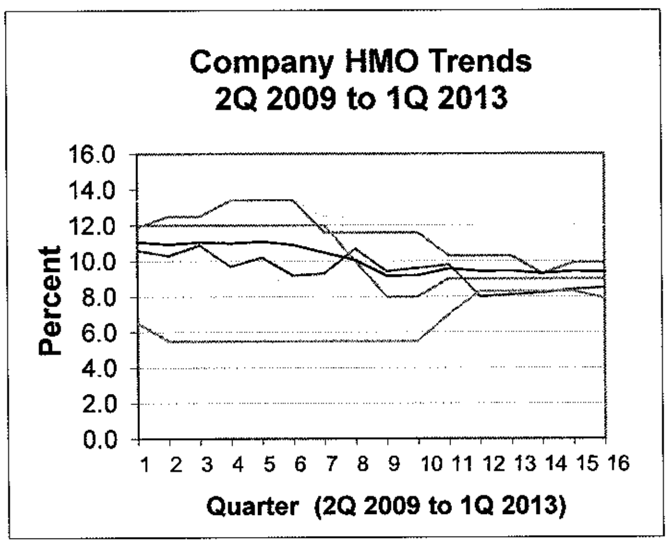
Schedule (JCZ)-9.2

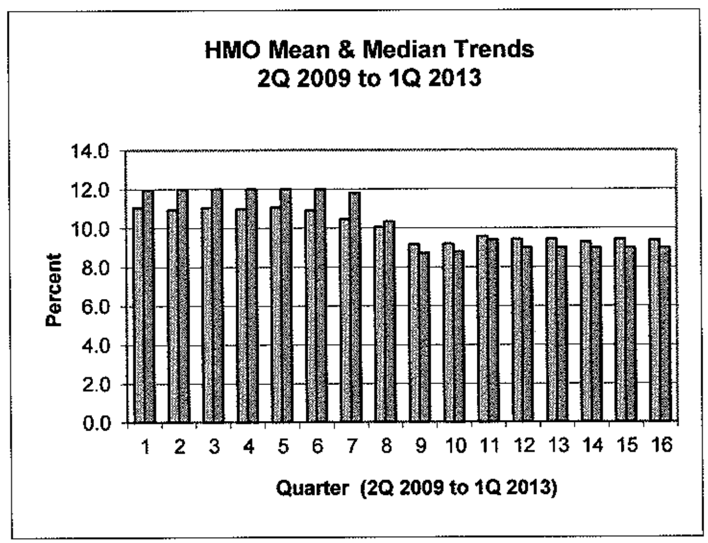
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

HMO Summary for 2Q 2009 to 1Q 2013

	Co. C	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
2 Q 2009	13.4	[redacted]	6.5	11.9	12.0	11.1	12.0	6.5	13.4
3 Q 2009	13.4	[redacted]	5.5	12.5	12.0	11.0	12.0	5.5	13.4
4 Q 2009	13.4	[redacted]	5.5	12.5	12.0	11.1	12.0	5.5	13.4
1 Q 2010	13.4	[redacted]	5.5	13.4	12.0	11.0	12.0	5.5	13.4
2 Q 2010	13.4	[redacted]	5.5	13.4	12.0	11.1	12.0	5.5	13.4
3 Q 2010	13.4	[redacted]	5.5	13.4	12.0	10.9	12.0	5.5	13.4
4 Q 2010	12.5	[redacted]	5.5	11.6	12.0	10.5	11.8	5.5	12.5
1 Q 2011	12.5	[redacted]	5.5	11.6	10.0	10.1	10.4	5.5	12.5
2 Q 2011	12.5	[redacted]	5.5	11.6	8.0	9.2	8.7	5.5	12.5
3 Q 2011	12.5	[redacted]	5.5	11.6	8.0	9.2	8.8	5.5	12.5
4 Q 2011	12.3	[redacted]	7.0	10.3	9.0	9.6	9.4	7.0	12.3
1 Q 2012	12.0	[redacted]	8.3	10.3	9.0	9.4	9.0	8.0	12.0
2 Q 2012	12.0	[redacted]	8.3	10.3	9.0	9.5	9.0	8.1	12.0
3 Q 2012	12.0	[redacted]	8.3	9.3	9.0	9.3	9.0	8.2	12.0
4 Q 2012	12.0	[redacted]	8.3	9.9	9.0	9.4	9.0	8.3	12.0
1 Q 2013	12.0	[redacted]	7.9	9.9	9.0	9.4	9.0	7.9	12.0



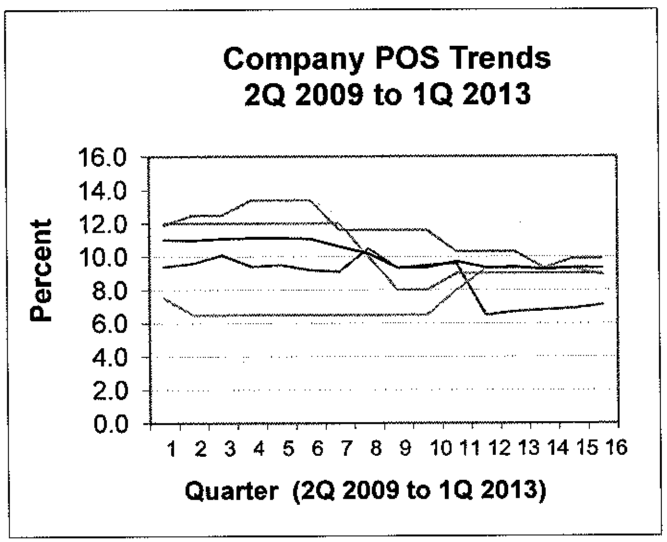


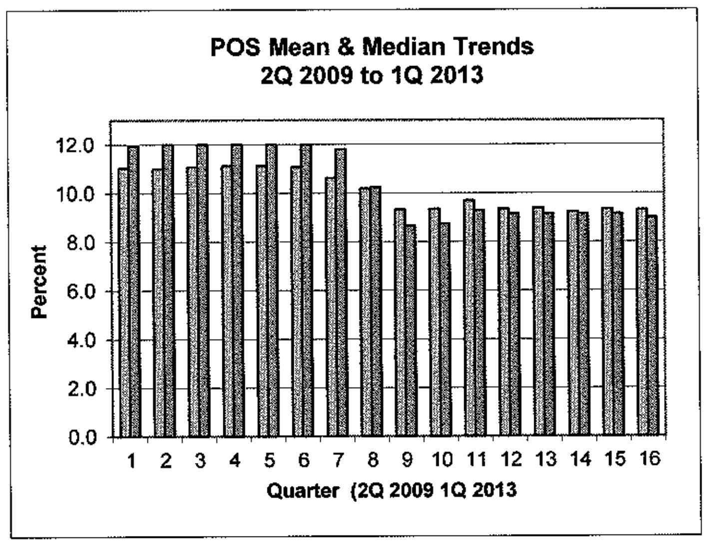
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

POS Summary for 2Q 2009 to 1Q 2013

									Range of Rates	
	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Low	High
2 Q 2009	13.4	[redacted]	[redacted]	7.5	11.9	12.0	11.0	12.0	7.5	13.4
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



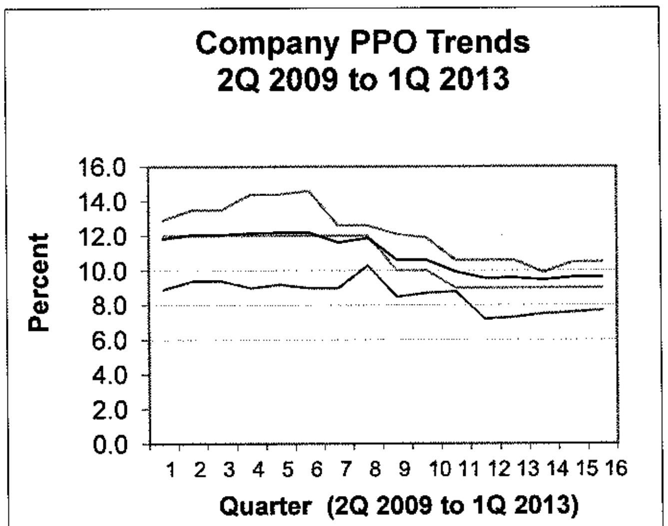


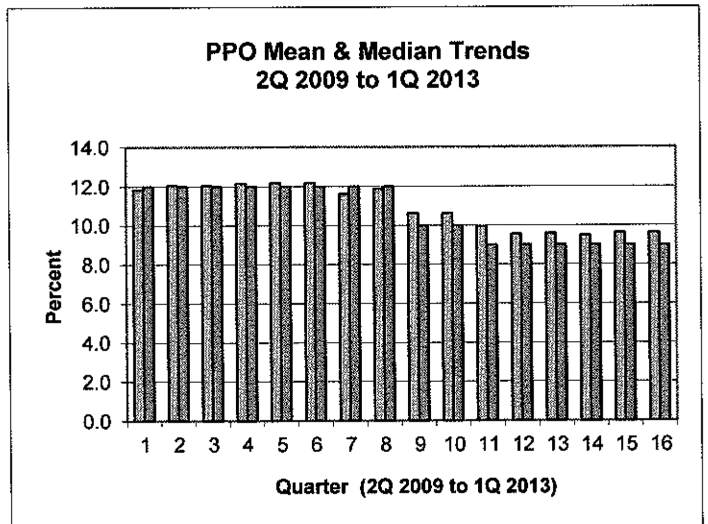
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

PPO Summary for 2Q 2009 to 1Q 2013

	Co. C	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
2 Q 2009	13.4	[redacted]		12.9	12.0	11.8	12.0	8.9	13.4
3 Q 2009	13.4	[redacted]		13.5	12.0	12.1	12.0	9.4	13.5
4 Q 2009	13.4	[redacted]		13.5	12.0	12.1	12.0	9.4	13.5
1 Q 2010	13.4	[redacted]		14.4	12.0	12.2	12.0	9.0	14.4
2 Q 2010	13.4	[redacted]		14.4	12.0	12.2	12.0	9.2	14.4
3 Q 2010	13.4	[redacted]		14.6	12.0	12.2	12.0	9.0	14.6
4 Q 2010	12.5	[redacted]		12.6	12.0	11.6	12.0	9.0	12.6
1 Q 2011	12.5	[redacted]		12.6	12.0	11.9	12.0	10.3	12.6
2 Q 2011	12.5	[redacted]		12.1	10.0	10.6	10.0	8.5	12.5
3 Q 2011	12.5	[redacted]		11.9	10.0	10.6	10.0	8.7	12.5
4 Q 2011	12.3	[redacted]		10.6	9.0	9.9	9.0	8.8	12.3
1 Q 2012	12.0	[redacted]		10.6	9.0	9.6	9.0	7.2	12.0
2 Q 2012	12.0	[redacted]		10.6	9.0	9.6	9.0	7.3	12.0
3 Q 2012	12.0	[redacted]		9.9	9.0	9.5	9.0	7.5	12.0
4 Q 2012	12.0	[redacted]		10.5	9.0	9.6	9.0	7.6	12.0
1 Q 2013	12.0	[redacted]		10.5	9.0	9.6	9.0	7.7	12.0



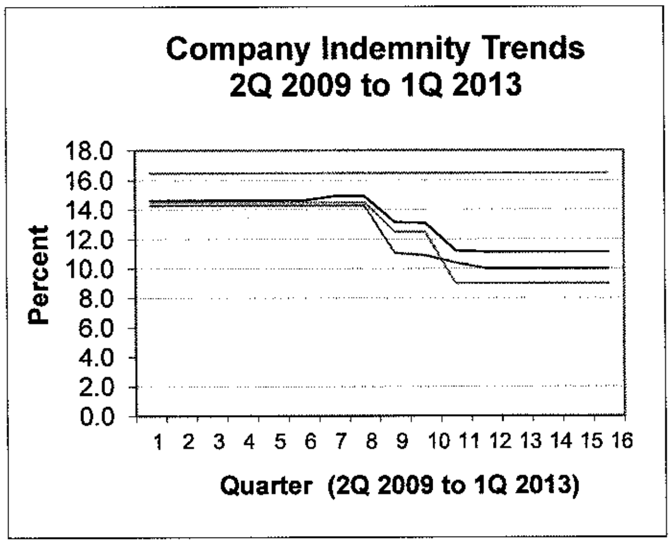


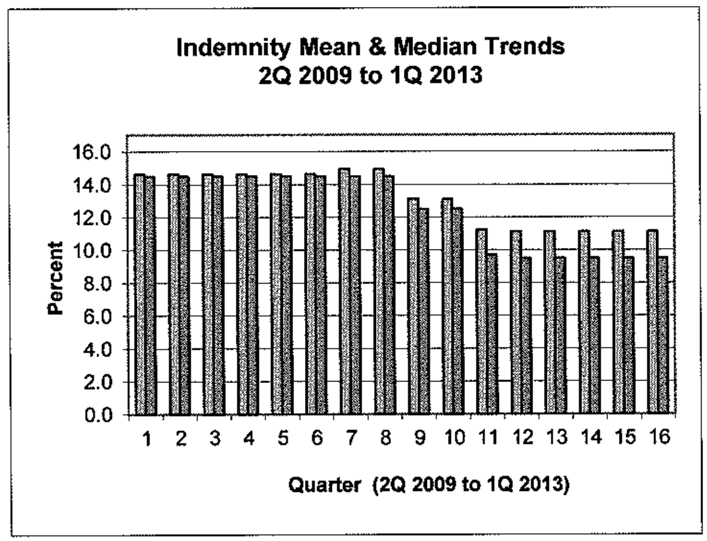
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Indemnity Summary for 2Q 2009 to 1Q 2013

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



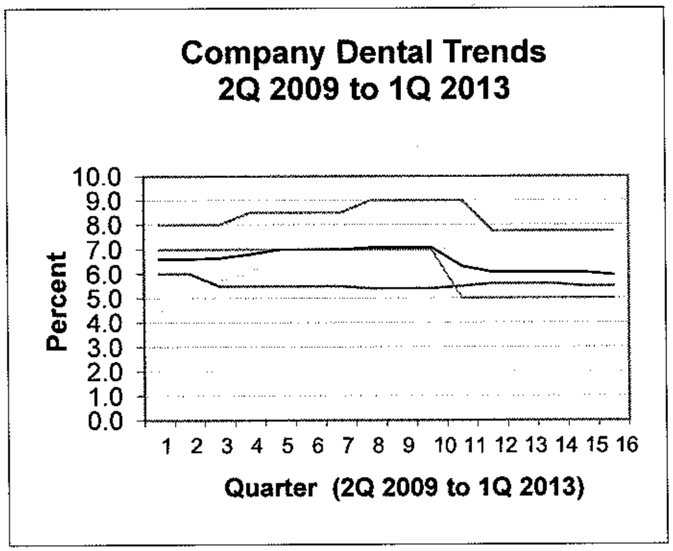


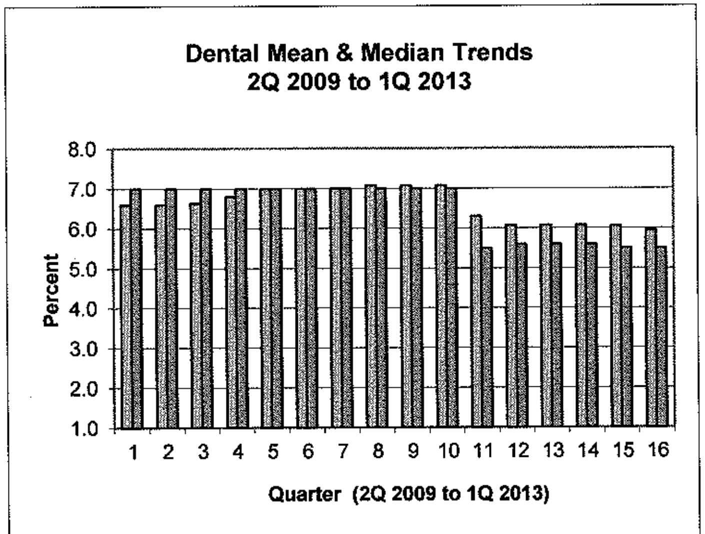
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Dental Summary for 2Q 2009 to 1Q 2013

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



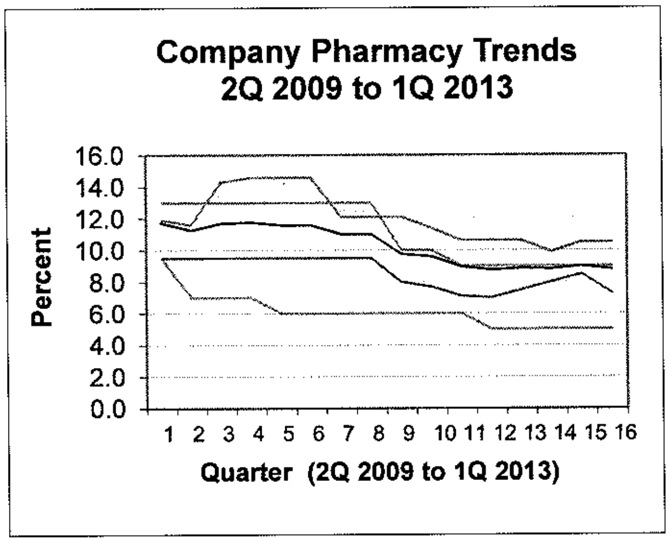


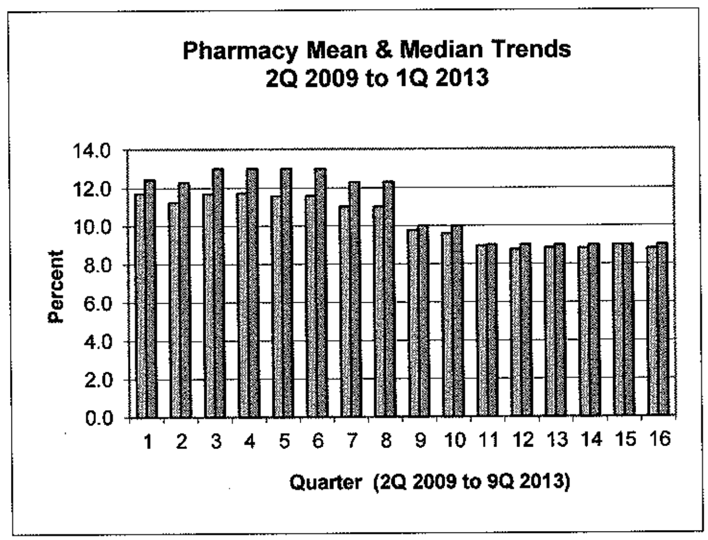
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Pharmacy Summary for 2Q 2009 to 1Q 2013

	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
2 Q 2009	13.4	[redacted]	[redacted]	9.5	11.9	13.0	11.7	12.5	9.5	13.4
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





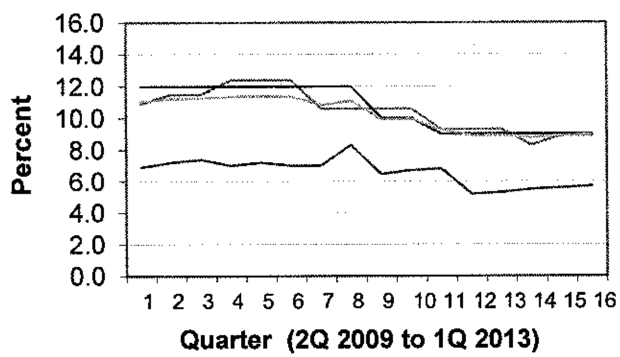
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

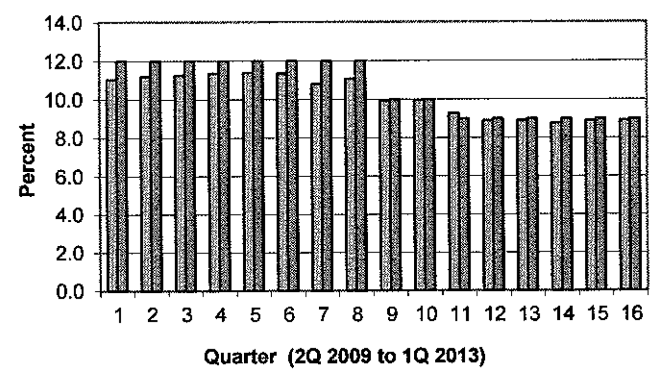
CDHP Summary for 2Q 2009 to 1Q 2013

	Co. C	[redacted]	[redacted]	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
2 Q 2009	13.4	[redacted]	[redacted]		10.9	12.0	11.0	12.0	6.9	13.4
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

Company CDHP Trends 2Q 2009 to 1Q 2013



CDHP Mean & Median Trends 2Q 2009 to 1Q 2013

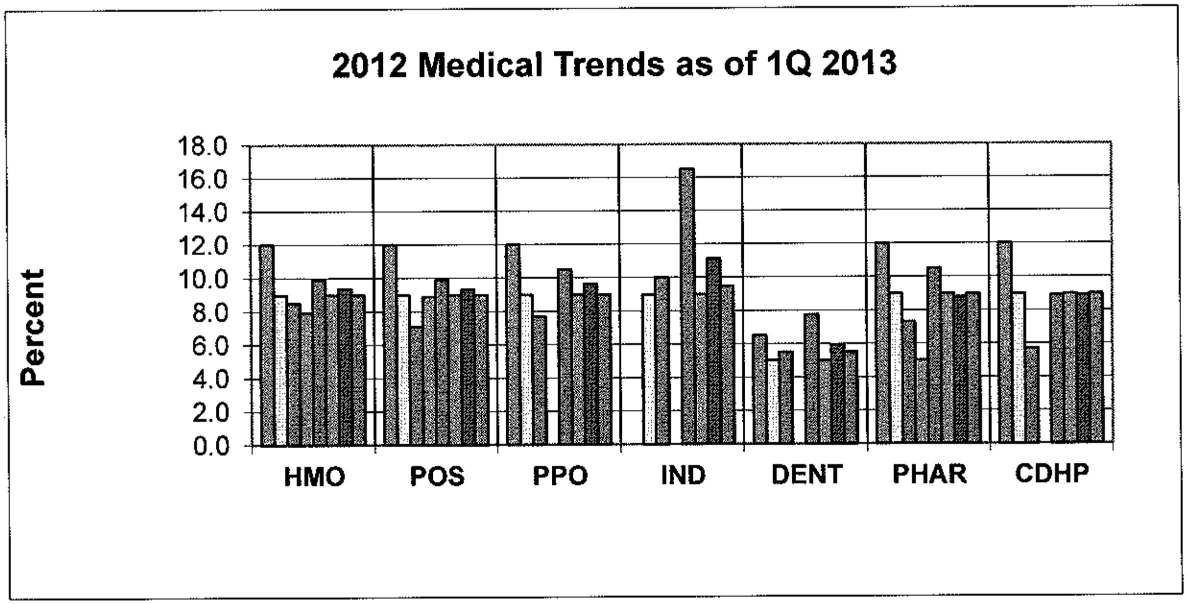


Schedule (JCZ)-9.3

LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY
VA, MD, DC Area

Annual Medical Trends Being Used for 1st Quarter 2013

	x	x		x	x				
								Range of Rates	
	Company C	Company D	Company E	Company F	Company G	Company I	Mean Ave	Median	Low	[illegible]
HMO	12.0	9.0	8.5	7.9	9.9	9.0	9.4	9.0	7.9	[illegible]
POS	12.0	9.0	7.1	8.9	9.9	9.0	9.3	9.0	7.1	[illegible]
PPO	12.0	9.0	7.7		10.5	9.0	9.6	9.0	7.7	[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	12.0	9.0	7.3	5.0	10.5	9.0	8.8	9.0	5.0	[illegible]
CDHP	12.0	9.0	6.7		8.9	9.0	8.9	9.0	5.7	[illegible]



Schedule (JCZ)-10
Adjustment 11

Delmarva Power & Light Company
Delaware Distribution
Remove Executive Incentive Compensation
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Distribution
1	Remove Executive Incentive Compensation	
2	Delaware Distribution	($2,175,633)
3		
4	Income Taxes	
5	State Income Tax	$189,280
6	Federal Income Tax	$695,224
7	Total Income Taxes	$884,504
8		
9	Earnings	$1,291,130

Schedule (JCZ)-11
Adjustment 12

Delmarva Power & Light Company
Delaware Distribution
Removal of Certain Executive/Officer Compensation
12 Months Ending December 2012

(1) Line No.	(2) Description	(3) Adjustment
1	Dividends Restricted Stock	($159,192)
2	Company Match Deferred Compensation	($50,184)
3	Tax Preparation Fee	($12,500)
4	Financial Planning Fee	($50,415)
5	Executive Physical Fee	($1,600)
6	Club Dues	($9,501)
7	Spousal Travel	($7,634)
8		
9		
10	Total Compensation	($291,026)
11		
12	DPL (as % of PHI)	30.03%
13	DPL Expense	($88,351)
14	DPL Electric (vs. Gas) %	82.93%
15	DPL Electric Expense	($73,269)
16	DPL Electric Distribution (vs. Transmission) %	92.81%
17	DPL Electric Distribution Expense	($67,084)
18	DPL Electric DE Distribution (vs. MD Distribution) %	58.58%
19	DPL Electric DE Distribution Expense	($39,419)
20		
21	State Income Tax Rate	8.70%
22	Effect on State income tax expense	$3,429
23		
24	Federal Taxable	($35,990)
25	Federal Income Tax Rate	35%
26	Effect on Federal income tax expense	$12,596
27		
28	Total Expense	($23,393)
29		
30	**Impact to Operating Income**	$23,393

Schedule (JCZ)-12
Adjustment 13

Delmarva Power & Light Company
Delaware Distribution
Normalization of Storm Restoration Expense
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Detail	
1	Delaware Electric Distribution Storm Restoration Expense		
2	(3 Year Average)	$11,253,977	(1)
3			
4	Delaware Electric Distribution Storm Restoration Expense		
5	Included in Test Period:	$12,025,188	
6			
7	Adjustment to Delaware Distribution O&M		
8	Storm Restoration Expense	($771,210)	
9			
10	SIT	$67,095	
11	FIT	$246,440	
12			
13	Net Expense	($457,675)	
14			
15	Earnings	$457,675	

(1) System Electric	Distribution	DE D Alloc	Major Storms	DE Distribution
12 m/e 12/31/10	$15,299,298	$8,993,860		$8,993,860
12 m/e 12/31/11	$15,966,187	$9,406,527	$3,336,357	$12,742,884
12 m/e 12/31/12	$12,688,671	$7,433,506	$4,591,682	$12,025,188
Average	$14,651,385	$8,611,298		$11,253,977

Derecho	$647,202
Hurricane Sandy	$3,944,480
Hurricane Irene	$3,336,357

Schedule (JCZ)-13
Adjustment 14

Delmarva Power & Light Company
Delaware Distribution
Reflect IRP Related Recurring Costs
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution
1	**Earnings**			
2	Annual Expense	$872,500	100%	$872,500 (1)
3	Amount in Test Period			$295,584
4	Adjustment			$576,916
5				
6	State Income Tax			($50,192)
7	Federal Income Tax			($184,354)
8	Total Expenses			$342,371
9				
10	Earnings			($342,371)

(1) Projected Bi-Annual IRP Cycle Expenses

ICF IPM Modeling & Scenarios	$350,000
Air Quality Modeling & Analysis	$200,000
Portfolio Analysis	$150,000
Life Cycle Analysis	$125,000
Annual Report to General Assembly	$20,000
PSC Consultants	$100,000
Outside Legal Expenses	$500,000
Consultant Support	$150,000
Special Studies	$150,000
Total Cost Per Cycle	$1,745,000
# of Years in IRP Cycle	2
Annualized Cost	$872,500

Schedule (JCZ)-14
Adjustment 15

Delmarva Power & Light Company
Delaware Distribution
Amortize IRP Related Deferred Costs
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution	
1	**Earnings**				
2	Amortization	$10,194	100%	$10,194	(1)
3					
4	State Income Tax			($887)	
5	Federal Income Tax			($3,258)	
6	Total Expenses			$6,050	
7					
8	Earnings			($6,050)	
9					
10	**Rate Base**				
11	Average Amortizable Balance	$96,847	100%	$96,847	(2)
12					
13	Deferred State Income Tax			($8,426)	
14	Deferred Federal Income Tax			($30,947)	
15	Net Rate Base			$57,474	

(1)	DP&L Delaware	$101,944
	Amortization period - years	**10**
	Annual amortization amount	$10,194
(2)	DP&L Delaware - beg balance	$101,944
	DP&L Delaware - end balance	$91,750
	DP&L Delaware - avg balance	$96,847

Schedule (JCZ)-15
Adjustment 16

Delmarva Power & Light Company
Delaware Distribution
Amortize RFP Related Deferred Costs
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution	
1	**Earnings**				
2	Amortization	$5,102	100%	$5,102	(1)
3					
4	State Income Tax			($444)	
5	Federal Income Tax			($1,630)	
6	Total Expenses			$3,028	
7					
8	Earnings			($3,028)	
9					
10	**Rate Base**				
11	Average Amortizable Balance	$48,469	100%	$48,469	(2)
12					
13	Deferred State Income Tax			($4,217)	
14	Deferred Federal Income Tax			($15,488)	
15	Net Rate Base			$28,764	

(1)	DP&L Delaware	$51,020
	Amortization period - years	**10**
	Annual amortization amount	$5,102
(2)	DP&L Delaware - beg balance	$51,020
	DP&L Delaware - end balance	$45,918
	DP&L Delaware - avg balance	$48,469

Schedule (JCZ)-16
Adjustment 17

Delmarva Power & Light Company
Delaware Distribution
Reflect AMI O&M Not in Cost of Service
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) $
1	O&M Expense	
2	Communication Network Backhaul Costs	$100,115
3	Silver Spring Networks Software License & Maintenance Fees	$236,861
4	IEE MDMS Software Maintenance Fees	$78,690
5	IBM Websphere Business Events Software Maintenance Fees	$9,131
6	Oracle Data Base Software Maintenance Fees	$62,374
7	MDMS Server Lease Cost	$78,534
8	UIQ Managed Services	$786,971
9	Incremental workforce - AMI Operations Analysts	$177,774
10	Incremental workforce - Translation Specialists	$380,640
11	IT System Support	$284,894
12		
13	Total	$2,195,985
14		
15	Income Taxes	
16	State Income Tax	($191,051)
17	Federal Income Tax	($701,727)
18	Total Income Taxes	($892,778)
19		
20	Net Expense	$1,303,207
21		
22	Earnings	($1,303,207)

Schedule (JCZ)-17
Adjustment 18

Delmarva Power & Light Company
Delaware Distribution
Reflect AMI O&M Savings Not in Cost of Service
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Blueprint Business Plan $	(4) 2012 Actual $	(5) Pending Savings* $	(6) Adjustment** $
1	Eliminate Manual Meter Reading Costs	$3,564,000	$3,790,505		
2	Implement Remote Turn-On/Turn-Off Functionality	$1,592,000	$0	($732,320)	($859,680)
3	Improve Billing Activities	$484,000	$191,760		($292,240)
4	Reduce Off-Cycle Meter Reading Labor Costs	$372,000	$268,849		($103,151)
5	Asset Optimization	$219,000	$0		
6	Reduce Expenses Related to Theft	$88,000	$0		($88,000)
7	Eliminate Hardware, Software and O&M Related to I-Tron Handheld Devices	$75,000	$99,087		
8	Reduce Volume of Customer Calls Related to Metering	$29,000	$16,416		($12,584)
9	Reduce Complaint Handling	$24,000	$11,803		($12,197)
10					
11	Total	$6,447,000	$4,378,420	($732,320)	($1,367,852)
12					
13	Income Taxes				
14	State Income Tax				$119,003
15	Federal Income Tax				$437,097
16	Total Income Taxes				$556,100
17					
18	Total - Net Expense				($811,752)
19					
20	Earnings				$811,752

Footnotes

* Remote Turn-On/Off

Customer-Requested Moves/Adds/Successions	$859,680
Failure to Pay and other Involuntary Service Terminations***	$732,320
Total	$1,592,000

** The purpose of the adjustment is to give customers the business plan level of savings if that savings level was not recorded in 2012. For the Manual Meter Reading and I-Tron O&M savings, the 2012 savings exceeded the business plan levels so no adjustment is required for them. Asset optimization savings are excluded from this adjustment since the reduction in avoided truck rolls during restoration efforts:
(1) - allow trucks to be redeployed and more quickly begin restoration efforts for customers without service - thus, reducing overall restoration time for the storms
(2) - have their avoided costs (i.e. labor and vehicle costs) already reflected in test period cost of service.

*** Achievement of these savings is subject to approval of currently pending request to amend the regulations found at Section 3002 of the Delaware Administrative Code. Once approval of the request is granted an depending on the timing of such approval, these savings would be credited as a regulatory asset.

Schedule (JCZ)-18
Adjustment 19

Delmarva Power & Light Company
Delaware Distribution
Reflect AMI Depreciation & Amortization Not in Cost of Service
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) $
1	Depreciation	
2	Meters	$596,292
3		
4	Amortization	
5	Meter Data Management System	$314,174
6	AMI-Related Systems in Customer Information System	$615,672
7	AMI Software	$263,883
8	AMI UIQ System	$251,490
9	AMI and IEE Systems	$574,022
10	AMI-Related Systems in Outage Management System, COP Software H/W and S/W	$185,935
11	Total	$2,205,176
12		
13	Total	$2,801,468
14		
15	Income Taxes	
16	State Income Tax	($243,728)
17	Federal Income Tax	($895,209)
18	Total Income Taxes	($1,138,937)
19		
20	Net Expense	$1,662,531
21		
22	Earnings	($1,662,531)

Schedule (JCZ)-19
Adjustment 20

Delmarva Power & Light Company
Delaware Distribution
Amortize Dynamic Pricing Regulatory Asset
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution	
1	Earnings				
2	Amortization - Dynamic Pricing Regulatory Asset	$446,632	100%	$446,632	(1)
3					
4	State Income Tax			($38,857)	
5	Federal Income Tax			($142,721)	
6	Total Expenses			$265,054	
7					
8	Earnings			($265,054)	
9					
10	Rate Base				
11	Average Amortizable Balance	$6,476,171	100%	$6,476,171	(2)
12					
13	Deferred State Income Tax			($563,427)	
14	Deferred Federal Income Tax			($2,069,460)	
15	Net Rate Base			$3,843,284	
16					
17					
18					
19	(1) DP&L Delaware	$6,699,487			
20	Amortization period - years	15			
21	Annual amortization amount	$446,632			
22					
23	(2) DP&L Delaware - beg balance	$6,699,487			
24	DP&L Delaware - end balance	$6,252,855			
25	DP&L Delaware - avg balance	$6,476,171			
26					
27					
28					
29	DPL DE Electric Dynamic Pricing Regulatory Asset				
30	Balance @ February 2013	$2,976,459			
31	Projected $ Up To Rate Effective Period				
32	Outbound Calls for DP Events	$526,318			
33	IT System Support	$133,333			
34	Customer Education	$1,562,500			
35	DP Analysis, Support & Call Overflow System	$192,160			
36	Amortization Expense - Dynamic Pricing-Related MDMS Costs	$852,629			
37	Amortization Expense - Dynamic Pricing-Related Billing System Interfaces	$326,361			
38	Return on Dynamic Pricing Regulatory Asset	$129,727			
39	Total	$3,723,028			
40	Total	$6,699,487			

Schedule (JCZ)-20
Adjustment 21

Delmarva Power & Light Company
Delaware Distribution
Reflect Dynamic Pricing O&M Not in Cost of Service
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution
1	**Earnings**			
2	Recurring Operating & Maintenance Expenses - Rate Effective Period			
3	Outbound Calls for DP Events	$526,318	100%	$526,318
4	IT System Support & Call Overflow System	$223,970	100%	$223,970
5	Total Recurring O&M Expenses	$750,288		$750,288
6				
7	State Income Tax			($65,275)
8	Federal Income Tax			($239,755)
9	Total Income Taxes			($305,030)
10				
11	Total Expenses			$445,258
12				
13	Earnings			($445,258)

Schedule (JCZ)-21
Adjustment 22

Delmarva Power & Light Company
Delaware Distribution
Reflect Dynamic Pricing Amortization Not in Cost of Service
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution
1	**Earnings**			
2	Amortization Expense			
3	Dynamic Pricing-Related MDMS Costs	$489,542	100%	$489,542
4	Dynamic Pricing-Related Billing System Interfaces	$746,050	100%	$746,050
5	Total Recurring O&M Expenses	$1,235,592		$1,235,592
6				
7	State Income Tax			($107,497)
8	Federal Income Tax			($394,833)
9	Total Income Taxes			($502,330)
10				
11	Total Expenses			$733,262
12				
13	Earnings			($733,262)

Schedule (JCZ)-22
Adjustment 23

Delmarva Power & Light Company
Delaware Distribution
Amortize Direct Load Control Regulatory Asset
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) DE D Alloc Factor	(5) DE Distribution	
1	**Earnings**				
2	Amortization	$663,192	100%	$663,192	(1)
3					
4	State Income Tax			($57,698)	
5	Federal Income Tax			($211,923)	
6	Total Expenses			$393,571	
7					
8	Earnings			($393,571)	
9					
10	**Rate Base**				
11	Average Amortizable Balance	$9,616,281	100%	$9,616,281	(2)
12					
13	Deferred State Income Tax			($836,616)	
14	Deferred Federal Income Tax			($3,072,883)	
15	Net Rate Base			$5,706,782	

(1)	DP&L Delaware	$9,947,877
	Amortization period - years	15
	Annual amortization amount	$663,192
(2)	DP&L Delaware - beg balance	$9,947,877
	DP&L Delaware - end balance	$9,284,685
	DP&L Delaware - avg balance	$9,616,281

DPL DE Electric Dynamic Pricing Regulatory Asset - Forecasted $ through December 2013

	Through December 2013	Total Program Costs
O&M		
Contracted Support	$ 1,155,000	$ 3,178,000
Program Administration	$ 354,375	$ 860,625
Maintenance Services	$ 87,471	$ 731,007
Evaluation	$ 50,000	$ 250,000
Total	$ 1,646,846	$ 5,019,632
Customer Bonus	$ 1,058,400	$ 2,781,000
Marketing	$ 2,674,350	$ 6,114,350
Equipment	$ 4,373,544	$ 11,491,710
Residential	$ 50,000	$ 50,000
Sub-Total	$ 9,803,140	$ 25,456,692
Returns on DLC Regulatory Asset	$ 144,737	
Total	$ 9,947,877	
# of Units (Switch & Thermostat) Deployed	19,600	51,600
% of Total	37.98%	100.00%

Schedule (JCZ)-23
Adjustment 24

Delmarva Power & Light Company
Delaware Distribution
Annualization of Depreciation on Year-end Plant
12 Months Ending December 2012

(1) Line No.	(2) Plant Category	(3) Annualized Depreciation Exp	(4) 12+0 ME Dec 2012 Depreciation Exp	(5) Adjustment
1	Distribution	$23,975,782	$23,222,015	$753,768
2				
3	General	$1,783,787	$2,261,435	($477,648)
4				
5	Common	$2,041,015	$1,957,500	$83,515
6				
7	Total	$27,800,585	$27,440,950	$359,635
8				
9				
10			**DSIT @ 8.7%**	($31,288)
11			**DFIT @ 35%**	($114,921)
12			**Total Expense**	$213,425
13				
14			**Earnings**	($213,425)
15				
16			**Rate Base**	($213,425)

Schedule (JCZ)-24
Adjustment 25

Delmarva Power & Light Company
Delaware Distribution
Normalize Other Taxes
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Amount
1	Reversal of Accrual Related to 2009 Assessment	$188,971
1		
2	Income Taxes	
3	State Income Tax	($16,440)
4	Federal Income Tax	($60,386)
5	Total Income Taxes	($76,826)
6		
7	Earnings	($112,145)

Schedule (JCZ)-25
Adjustment 26

Delmarva Power
Delaware Distribution
2013 Forecasted Reliability Closings

(1) Line No.	(2) Item		(3) $
1	**Rate Base**		
2	Plant in Service		
3	Reliability closings January 2013 - December 2013		$74,956,809
4	Retirements January 2013 - December 2013		($4,950,000)
5	Adjustment to Plant in Service		$70,006,809
6			
7	Depreciation reserve		
8	Retirements January 2013 - December 2013		($4,950,000)
9	Depreciation expense		$917,089
10	Adjustment to Depreciation Reserve		($4,032,911)
11			
12	Net Plant		$74,039,720
13			
14	Deferred Taxes		($7,245,580)
15			
16	Total Rate Base		$66,794,140
17			
18	**Earnings**		
19	Depreciation Expense		
20	Reliability closings January 2013 - December 2013		$1,963,868
21	Retirements January 2013 - December 2013		($129,690)
22	Adjustment to Depreciation Expense		$1,834,178
23			
24	State Income Tax		($3,260,621)
25	Federal Income Tax		($11,976,224)
26	Deferred State Income Tax		$3,101,048
27	Deferred Federal Income Tax		$11,390,112
28			
29	Operating Expense		$1,088,493
30			
31	Operating Income		($1,088,493)
32			
33	Total Earnings		($1,088,493)
Tax Depreciation			
	Basis		$74,956,809
	Rate		50.00%
	Tax Depreciation exp		$37,478,405
	SIT	8.70%	($3,260,621)
	FIT	35.00%	($11,976,224)
	Deferred Tax Basis		
	Tax Deprec Exp		$37,478,405
	Book Deprec Exp		$1,834,178
	Tax over Book		$35,644,226
	DSIT	8.70%	$3,101,048
	DFIT	35.00%	$11,390,112

Delmarva Power & Light Company
Delaware Distribution
Amortization of Loss/Gain on Refinancings
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) First Mortgage Bonds Aug-93	(4) Demand Rate Bonds Nov-93	(5) Tax Exempt Bonds Sep-00	(6) Tax Exempt Bonds Sep-00	(7) Tax Exempt Bonds Sep-00	(8) Tax Exempt Bonds Oct-00	(9) Tax Exempt Bonds Jul-01
1	Total Company	$702,894	$348,751	$576,741	$1,438,608	$558,772	$235,481	$490,000
2	Electric Amount Refinanced	$660,720	$327,826	$531,525	$1,325,821	$514,964	$217,019	$451,584
3	Delaware Electric Distribution %	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
4	Delaware Electric Distribution	$259,146	$128,579	$208,473	$520,010	$201,978	$85,119	$177,119
5	Deferred SIT	($22,546)	($11,186)	($18,137)	($45,241)	($17,572)	($7,405)	($15,409)
6	Deferred FIT	($82,810)	($41,087)	($66,618)	($166,169)	($64,542)	($27,200)	($56,598)
7								
8	**Earnings**							
9	Amortization	$10,723	$6,123	$13,898	$26,667	$14,961	$5,007	$8,856
10	DSIT	($933)	($533)	($1,209)	($2,320)	($1,302)	($436)	($770)
11	DFIT	($3,427)	($1,957)	($4,441)	($8,521)	($4,781)	($1,600)	($2,830)
12	Total Expense	$6,364	$3,634	$8,248	$15,826	$8,879	$2,971	$5,256
13	Earnings	($6,364)	($3,634)	($8,248)	($15,826)	($8,879)	($2,971)	($5,256)
14								
15	**Rate Base**							
16	Amortizable Balance - 12/31/11	$61,659	$17,348	$50,960	$217,782	$32,416	$28,790	$84,131
17	Amortizable Balance - 12/31/12	$50,936	$11,225	$37,062	$191,115	$17,455	$23,783	$75,276
18	Average Balance	$56,297	$14,287	$44,011	$204,448	$24,936	$26,287	$79,704
19								
20	Deferred SIT - 12/31/11	($5,364)	($1,509)	($4,434)	($18,947)	($2,820)	($2,505)	($7,319)
21	Deferred SIT - 12/31/12	($4,431)	($977)	($3,224)	($16,627)	($1,519)	($2,069)	($6,549)
22	Average Balance	($4,898)	($1,243)	($3,829)	($17,787)	($2,169)	($2,287)	($6,934)
23								
24	Deferred FIT - 12/31/11	($19,703)	($5,544)	($16,284)	($69,592)	($10,359)	($9,200)	($26,884)
25	Deferred FIT - 12/31/12	($16,276)	($3,587)	($11,843)	($61,071)	($5,578)	($7,600)	($24,054)
26	Average Balance	($17,990)	($4,565)	($14,064)	($65,331)	($7,968)	($8,400)	($25,469)
27								
28	Net Year End Balance	$30,228	$6,662	$21,994	$113,417	$10,359	$14,114	$44,672
29								
30	Amortization begin date (a)	August-93	November-93	September-00	September-00	September-00	October-00	July-01
31	Amortization period (months)	290	252	180	234	162	204	240
32	Amortization as of 12/31/11	221	218	136	136	136	135	126
33	Amortization as of 12/31/12	233	230	148	148	148	147	138

(a) rounded to nearest full month

Delmarva Power & Light Company
Delaware Distribution
Amortization of Loss/Gain on Refinancings
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Tax Exempt Bonds Jul-01	(4) First Mortgage Bonds Jul-01	(5) Medium Term Notes Jul-01	(6) First Mortgage Bonds Jul-01	(7) Medium Term Notes Jul-01	(8) Medium Term Notes Jul-01
1	Total Company	$690,000	$3,762,881	$3,058,389	$1,634,283	$1,073,753	($595,660)
2	Electric Amount Refinanced	$635,904	$3,467,871	$2,818,611	$1,506,155	$989,571	($548,960)
3	Delaware Electric Distribution %	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
4	Delaware Electric Distribution	$249,412	$1,360,158	$1,105,507	$590,740	$388,126	($215,312)
5	Deferred SIT	($21,699)	($118,334)	($96,179)	($51,394)	($33,767)	$18,732
6	Deferred FIT	($79,700)	($434,638)	($353,265)	($188,771)	($124,026)	$68,803
7							
8	**Earnings**						
9	Amortization	$14,671	$95,450	$56,936	$28,700	$24,907	($12,984)
10	DSIT	($1,276)	($8,304)	($4,953)	($2,497)	($2,167)	$1,130
11	DFIT	($4,688)	($30,501)	($18,194)	($9,171)	($7,959)	$4,149
12	Total Expense	$8,707	$56,645	$33,789	$17,032	$14,781	($7,705)
13	Earnings	($8,707)	($56,645)	($33,789)	($17,032)	($14,781)	$7,705
14							
15	**Rate Base**						
16	Amortizable Balance - 12/31/11	$95,364	$357,936	$507,679	$289,391	$126,608	($78,984)
17	Amortizable Balance - 12/31/12	$80,692	$262,487	$450,743	$260,691	$101,702	($66,000)
18	Average Balance	$88,028	$310,211	$479,211	$275,041	$114,155	($72,492)
19							
20	Deferred SIT - 12/31/11	($8,297)	($31,140)	($44,168)	($25,177)	($11,015)	$6,872
21	Deferred SIT - 12/31/12	($7,020)	($22,836)	($39,215)	($22,680)	($8,848)	$5,742
22	Average Balance	($7,658)	($26,988)	($41,691)	($23,929)	($9,931)	$6,307
23							
24	Deferred FIT - 12/31/11	($30,473)	($114,379)	($162,229)	($92,475)	($40,458)	$25,239
25	Deferred FIT - 12/31/12	($25,785)	($83,878)	($144,035)	($83,304)	($32,499)	$21,090
26	Average Balance	($28,129)	($99,128)	($153,132)	($87,889)	($36,478)	$23,165
27							
28	Net Year End Balance	$47,887	$155,773	$267,494	$154,707	$60,355	($39,168)
29							
30	Amortization begin date (a)	July-01	July-01	July-01	July-01	July-01	July-01
31	Amortization period (months)	204	171	233	247	187	199
32	Amortization as of 12/31/11	126	126	126	126	126	126
33	Amortization as of 12/31/12	138	138	138	138	138	138

(a) rounded to nearest full month

Delmarva Power & Light Company
Delaware Distribution
Amortization of Loss/Gain on Refinancings
12 Months Ending December 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	(7) First Mortgage Bonds May-03	(8) Tax Exempt Bonds Aug-03
1	Total Company	$1,340,233	$1,388,233	$944,292	$1,313,393	$1,298,560	$1,347,719
2	Electric Amount Refinanced	$1,235,159	$1,166,115	$793,205	$1,103,250	$1,090,790	$1,132,084
3	Delaware Electric Distribution %	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
4	Delaware Electric Distribution	$484,450	$457,370	$311,109	$432,713	$427,827	$444,023
5	Deferred SIT	($42,147)	($39,791)	($27,066)	($37,646)	($37,221)	($38,630)
6	Deferred FIT	($154,806)	($146,153)	($99,415)	($138,274)	($136,712)	($141,887)
7							
8	**Earnings**						
9	Amortization	$18,936	$22,774	$15,491	$25,330	$25,044	$25,992
10	DSIT	($1,647)	($1,981)	($1,348)	($2,204)	($2,179)	($2,261)
11	DFIT	($6,051)	($7,277)	($4,950)	($8,094)	($8,003)	($8,306)
12	Total Expense	$11,238	$13,515	$9,193	$15,032	$14,862	$15,425
13	Earnings	($11,238)	($13,515)	($9,193)	($15,032)	($14,862)	($15,425)
14							
15	**Rate Base**						
16	Amortizable Balance - 12/31/11	$285,621	$231,532	$162,654	$189,972	$210,783	$225,260
17	Amortizable Balance - 12/31/12	$266,684	$208,758	$147,163	$164,642	$185,739	$199,269
18	Average Balance	$276,152	$220,145	$154,909	$177,307	$198,261	$212,264
19							
20	Deferred SIT - 12/31/11	($24,849)	($20,143)	($14,151)	($16,528)	($18,338)	($19,598)
21	Deferred SIT - 12/31/12	($23,202)	($18,162)	($12,803)	($14,324)	($16,159)	($17,336)
22	Average Balance	($24,025)	($19,153)	($13,477)	($15,426)	($17,249)	($18,467)
23							
24	Deferred FIT - 12/31/11	($91,270)	($73,986)	($51,976)	($60,705)	($67,356)	($71,982)
25	Deferred FIT - 12/31/12	($85,219)	($66,709)	($47,026)	($52,611)	($59,353)	($63,676)
26	Average Balance	($88,245)	($70,347)	($49,501)	($56,658)	($63,354)	($67,829)
27							
28	Net Year End Balance	$158,264	$123,888	$87,334	$97,707	$110,227	$118,256
29							
30	Amortization begin date (a)	July-01	February-02	June-02	June-02	May-03	August-03
31	Amortization period (months)	307	241	241	205	205	205
32	Amortization as of 12/31/11	126	119	115	115	104	101
33	Amortization as of 12/31/12	138	131	127	127	116	113

(a) rounded to nearest full month

Delmarva Power & Light Company
Delaware Distribution
Amortization of Loss/Gain on Refinancings
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Trust Preferred May-04	(4) First Mortgage Bonds Jun-05	(5) Preferred Stock Jan-07	(6) Tax Exempt Bonds Mar-08	(7) Tax Exempt Bonds Mar-08	(8) Tax Exempt Bonds Mar-08
1	Total Company	$1,943,173	$4,497,500	$740,468	$439,979	$668,515	$790,973
2	Electric Amount Refinanced	$1,632,265	$3,777,900	$621,993	$369,582	$561,553	$664,417
3	Delaware Electric Distribution %	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
4	Delaware Electric Distribution	$640,202	$1,481,757	$243,956	$144,956	$220,250	$260,596
5	Deferred SIT	($55,698)	($128,913)	($21,224)	($12,611)	($19,162)	($22,672)
6	Deferred FIT	($204,577)	($473,495)	($77,956)	($46,321)	($70,381)	($83,273)
7							
8	**Earnings**						
9	Amortization	$37,475	$74,088	$24,396	$6,466	$9,082	$8,544
10	DSIT	($3,260)	($6,446)	($2,122)	($563)	($790)	($743)
11	DFIT	($11,975)	($23,675)	($7,796)	($2,066)	($2,902)	($2,730)
12	Total Expense	$22,240	$43,967	$14,478	$3,838	$5,390	$5,071
13	Earnings	($22,240)	($43,967)	($14,478)	($3,838)	($5,390)	($5,071)
14							
15	**Rate Base**						
16	Amortizable Balance - 12/31/11	$352,892	$994,012	$121,978	$120,168	$185,434	$227,843
17	Amortizable Balance - 12/31/12	$315,417	$919,924	$97,583	$113,702	$176,352	$219,299
18	Average Balance	$334,154	$956,968	$109,780	$116,935	$180,893	$223,571
19							
20	Deferred SIT - 12/31/11	($30,702)	($86,479)	($10,612)	($10,455)	($16,133)	($19,822)
21	Deferred SIT - 12/31/12	($27,441)	($80,033)	($8,490)	($9,892)	($15,343)	($19,079)
22	Average Balance	($29,071)	($83,256)	($9,551)	($10,173)	($15,738)	($19,451)
23							
24	Deferred FIT - 12/31/11	($112,767)	($317,636)	($38,978)	($38,400)	($59,256)	($72,807)
25	Deferred FIT - 12/31/12	($100,791)	($293,962)	($31,182)	($36,333)	($56,353)	($70,077)
26	Average Balance	($106,779)	($305,799)	($35,080)	($37,367)	($57,804)	($71,442)
27							
28	Net Year End Balance	$187,184	$545,929	$57,910	$67,476	$104,656	$130,143
29							
30	Amortization begin date (a)	May-04	June-05	Jan-07	Mar-08	Mar-08	Mar-08
31	Amortization period (months)	205	240	120	269	291	366
32	Amortization as of 12/31/11	92	79	60	46	46	46
33	Amortization as of 12/31/12	104	91	72	58	58	58

(a) rounded to nearest full month

Delmarva Power & Light Company
Delaware Distribution
Amortization of Loss/Gain on Refinancings
12 Months Ending December 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	(7) Tax Exempt Bonds Dec-10	(8) Tax Exempt Bonds Jun-11
1	Total Company	$176,784	$655,565	$84,228	$148,731	$171,299	$634,231
2	Electric Amount Refinanced	$148,499	$550,675	$70,752	$124,934	$143,891	$532,754
3	Delaware Electric Distribution %	39.22%	39.22%	39.22%	39.22%	39.22%	39.22%
4	Delaware Electric Distribution	$58,244	$215,984	$27,750	$49,001	$56,437	$208,955
5	Deferred SIT	($5,067)	($18,791)	($2,414)	($4,263)	($4,910)	($18,179)
6	Deferred FIT	($18,612)	($69,018)	($8,867)	($15,658)	($18,034)	($66,772)
7							
8	**Earnings**						
9	Amortization	$2,608	$9,323	$4,826	$3,360	$3,210	$14,008
10	DSIT	($227)	($811)	($420)	($292)	($279)	($1,219)
11	DFIT	($833)	($2,979)	($1,542)	($1,074)	($1,026)	($4,476)
12	Total Expense	$1,548	$5,533	$2,864	$1,994	$1,905	$8,313
13	Earnings	($1,548)	($5,533)	($2,864)	($1,994)	($1,905)	($8,313)
14							
15	**Rate Base**						
16	Amortizable Balance - 12/31/11	$48,464	$181,023	$12,467	$45,361	$52,959	$0
17	Amortizable Balance - 12/31/12	$45,856	$171,699	$7,641	$42,001	$49,750	$186,776
18	Average Balance	$47,160	$176,361	$10,054	$43,681	$51,355	$93,388
19							
20	Deferred SIT - 12/31/11	($4,216)	($15,749)	($1,085)	($3,946)	($4,607)	$0
21	Deferred SIT - 12/31/12	($3,989)	($14,938)	($665)	($3,654)	($4,328)	($16,249)
22	Average Balance	($4,103)	($15,343)	($875)	($3,800)	($4,468)	($8,125)
23							
24	Deferred FIT - 12/31/11	($15,487)	($57,846)	($3,984)	($14,495)	($16,923)	$0
25	Deferred FIT - 12/31/12	($14,653)	($54,867)	($2,442)	($13,421)	($15,898)	($59,684)
26	Average Balance	($15,070)	($56,356)	($3,213)	($13,958)	($16,410)	($29,842)
27							
28	Net Year End Balance	$27,213	$101,895	$4,535	$24,926	$29,524	$110,842
29							
30	Amortization begin date (a)	Apr-08	Apr-08	Nov-08	Dec-10	Dec-10	Jun-11
31	Amortization period (months)	268	278	69	175	211	179
32	Amortization as of 12/31/11	45	45	38	13	13	7
33	Amortization as of 12/31/12	57	57	50	25	25	19

(a) rounded to nearest full month

Delmarva Power & Light Company
Delaware Distribution
Amortization of Loss/Gain on Refinancings
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Total
1	Total Company	$32,558,769
2	Electric Amount Refinanced	$28,618,431
3	Delaware Electric Distribution %	
4	Delaware Electric Distribution	$11,224,635
5	Deferred SIT	($976,543)
6	Deferred FIT	($3,586,832)
7		
8	**Earnings**	
9	Amortization	$624,868
10	DSIT	($54,363)
11	DFIT	($199,676)
12	Total Expense	$370,828
13	Earnings	($370,828)
14		
15	**Rate Base**	
16	Amortizable Balance - 12/31/11	$5,439,504
17	Amortizable Balance - 12/31/12	$5,015,421
18	Average Balance	$5,227,463
19		
20	Deferred SIT - 12/31/11	($473,237)
21	Deferred SIT - 12/31/12	($436,342)
22	Average Balance	($454,789)
23		
24	Deferred FIT - 12/31/11	($1,738,194)
25	Deferred FIT - 12/31/12	($1,602,678)
26	Average Balance	($1,670,436)
27		
28	Net Year End Balance	$2,976,401
29		
30	Amortization begin date (a)	
31	Amortization period (months)	
32	Amortization as of 12/31/11	
33	Amortization as of 12/31/12	

(a) rounded to nearest full month

Schedule (JCZ)-27
Adjustment 28

Delmarva Power & Light Company
Delaware Distribution
Remove Qualified Fuel Cell Provider Project Costs
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) DE Distribution
1	**Earnings**	
1	Expense in Test Period	$142,865
2	Adjustment to Remove	($142,865)
3		
4	State Income Tax	$12,429
5	Federal Income Tax	$45,653
6	Total Expenses	($84,783)
7		
8	Earnings	$84,783

Delmarva Power & Light Company
Delaware Distribution
Recovery of Tax on OPEB Medicare Tax Subsidy
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) DE Distribution	
1	**Earnings**		
2	Amortization	$36,836	(1)
3			
4	State Income Tax	($3,205)	
5	Federal Income Tax	($11,771)	
6	Total Expenses	$21,860	
7			
8	Earnings	($21,860)	
9			
10	**Rate Base**		
11	Average Amortizable Balance	$92,089	(2)
12			
13	Deferred State Income Tax	($8,012)	
14	Deferred Federal Income Tax	($29,427)	
15	Net Rate Base	$54,650	

(1)	DP&L Delaware	$110,507
	Amortization period - years	3
	Annual amortization amount	$36,836
	DPL Electric Delaware Distribution	
(2)	Beg. Balance	$110,507
	End. Balance	$73,671
	Avg. Balance	$92,089

Schedule (JCZ)-29
Adjustment 30

Delmarva Power & Light Company
Delaware Distribution
Remove Post-80 ITC Amortization
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) System Electric	(4) Delaware Distribution	(5) Delaware Distribution
1	**Post 1980 Vintage ITC Amortization**			
2	Transmission	108,391	0.0000	$0
3				
4	Distribution - DE	$186,300	1.0000	$186,300
5	Distribution - MD	$118,915	0.0000	$0
6	Distribution - VA	$16,232	0.0000	$0
7				
8	General & Common	$118,518	0.5858	$69,432
9				
10	Total Expense	$548,356		$255,733
11				
12	Earnings	($548,356)		($255,733)

Schedule (JCZ)-30
Adjustment 31

Delmarva Power & Light Company
Delaware Distribution
Reflect Credit Facilities Cost
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) DE Distribution	
1	**Earnings**		
2	Expense	$337,108	(1)
3			
4	State Income Tax	($29,328)	
5	Federal Income Tax	($107,723)	
6	Total Expenses	$200,057	
7			
8	Earnings	($200,057)	
9			
10	**Rate Base**		
11	Average Amortizable Balance	$520,111	(2)
12			
13			
14			
15	(1) Annual amortization of start-up costs	$254,582	
16	Annual cost of maintaining credit facility	$483,507	
17	Total DPL expense	$738,089	
18			
19	DPL Electric	$619,995	
20	Allocation to Distribution	92.81%	
21	DPL Distribution	$575,428	
22	Allocation to Delaware Distribution	58.58%	
23	DPL DE Distribution	$337,108	
24			
25	(2) DPL 13 mos average	$1,138,769	
26			
27	DPL Electric	$956,566	
28	Allocation to Distribution	92.81%	
29	DPL Distribution	$887,806	
30	Allocation to Delaware Distribution	58.58%	
31	DPL DE Distribution	$520,111	

Schedule (JCZ)-31
Adjustment 32

Delmarva Power & Light Company
Delaware Distribution
Removal of RPS Labor Charges
12 Months Ending December 2012

(1) Line No.	(2) Item	(3) Amount
1	Removal of RPS Labor Charges	($69,317)
1		
2	Income Taxes	
3	State Income Tax	$6,031
4	Federal Income Tax	$22,150
5	Total Income Taxes	$28,181
6		
7	Total Expenses	($41,136)
8		
9	Earnings	$41,136