— APARTMENT AND OFFICE —
BUILDING ASSOCIATION OF
METROPOLITAN WASHINGTON

December 14, 2016

Electronic Filing and Federal Express

Brinda Westbrook-Sedgwick
Commission Secretary
D.C. Public Service Commission
1325 G Street, N.W., Suite 800
Washington, D.C. 20005

Re: Formal Case No. 1139
In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service
AOBA Direct Testimony of Bruce R. Oliver

Dear Ms. Westbrook-Sedgwick:

Enclosed please find an original and fifteen (15) copies of the Direct Testimony of Bruce R. Oliver on behalf of the Apartment and Office Building Association of Metropolitan.

Also enclosed is an additional copy. Please stamp the additional copy and return it to me in the enclosed envelope. Please call me if you have any questions. Thank you for your attention in this matter.

Sincerely,

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CERTIFICATE OF SERVICE
Formal Case No. 1139

I hereby certify on this 14th day of December, 2016 that the attached **Direct Testimony of Bruce R. Oliver** was filed electronically on behalf of the Apartment and Office Building Association of Metropolitan Washington in Formal Case No. 1139 and an original and fifteen (15) copies of the above testimony was sent by Federal Express to Brinda Westbrook-Sedgwick, Commission Secretary, District of Columbia Public Service Commission, 1325 G Street, N.W., Suite 800, Washington, D.C. 20005, and copies were either hand-delivered, or mailed, first-class, postage prepaid, or electronically delivered to the service list below:

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Before the

PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
The Application of Potomac Electric	)	
Power Company for Authority to Increase	)	**Formal Case No. 1139**
Existing Retail Rates and Charges	)	
For Electric Distribution Service	)	

VOLUME I OF II: DIRECT TESTIMONY OF AOBA WITNESS
BRUCE R. OLIVER

December 14, 2016

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TABLE OF CONTENTS

LIST OF EXHIBITS

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric Power	)	Formal Case No. 1139
Company for Authority to Increase	)	
Existing Retail Rates and Charges for Electric	)	
Distribution Service	)	

The Apartment and Office Building Association of Metropolitan Washington hereby submits the following Issue Index to the Direct Testimony of Bruce R. Oliver.

Issue	Question	Page Numbers
1	Is Pepco's proposed $85,477,000 increase in base distribution rates just and reasonable?	Page 5 through Page 9
2(a)	Are the proposed adjustments to the test year data for known and measureable changes reasonable?	Page 5 through Page 9; Page 15; Page 62 through Page 82
3	Are Pepco's requested cost of capital and capital structure just and reasonable?	Page 5 through Page 9; Page 25 through Page 40
3(a)	What cost of common equity should Pepco be authorized to earn?	Page 5 through Page 9; Page 25 through Page 40
4	Should Pepco's BSA Mechanism be continued and, if so, what changes to the mechanism, if any, are necessary and appropriate?	Page 5 through Page 9; Page 40 through Page 63
4(a)	Has Pepco reasonably and appropriately developed the revenues per customer that will be used in BSA determinations subsequent to the conclusion of this proceeding?	Page 54 through Page 58

4(b)	If the BSA is continued, what forecasts of kWh per rate class should be used in the monetary computation of monthly rate adjustment ($/kWh)?	Page 40 through Page 43
4 (c)	Are Pepco's test year numbers of customers and revenues developed in a manner consistent with the actual data presented in its BSA filings?	Page 43 through Page 49
4(d)	How would the BSA mechanism be adjusted if MMA customer count changes from number of dwelling units to the number of buildings?	Page 58 through Page 60
6	Are Pepco's proposed operating revenues, test year sales, and number of customers, as adjusted, just and reasonable?	Page 63 through Page 83
6(a)	Is Pepco's weather normalization study reasonable and in compliance with the previous Commission directives?	Page 64 through Page 73
7	Are Pepco's proposed operating expenses, as adjusted, just and reasonable?	Page 63 through Page 83
7(a)	Are Pepco's proposed adjustments for Supplementary Executive Retirement Plan (SERP), Annual Incentive Plan (AIP), Executive Incentive Compensation Plan (EICP) and Long Term Incentive Plan (LTIP) expenses just and reasonable?	Page 63 through Page 83
10	Are all Formal Case No. 1119 Merger Commitments properly reflected in the Application?	Page 71 through Page 74; Page 93
10(a)	Is Pepco's proposed treatment of the costs to achieve and merger synergy savings just and reasonable and consistent with Merger Commitment 27?	Page 71 through Page 74; Page 93

10(b)	Is Pepco's request to establish regulatory assets for costs to achieve appropriate and reasonable?	
10(c)	Are all the merger transaction costs (as defined in Merger Commitment 28) properly excluded from the test year?	
10(d)	Is Pepco's proposed allocation of Customer Base Rate Credits and the new Rider CBRC just and reasonable?	
10(e)	Is Pepco's proposal for an Incremental Offset just and reasonable?	
13	Is Pepco's proposed allocation of its revenue requirement just and reasonable?	
13(a)	Is Pepco's proposed plan for eliminating negative class rates of return reasonable?	
19	Should the Commission explore alternative ratemaking structures? (For example, a fully forecasted test year, Performance Based Ratemaking ("PBR"), price regulation, ranges of authorized return, categories of services, price-indexing, and or other alternative mechanisms). If so, which, why, and what elements of Pepco's rates, incentives, and operations and expenses are potential candidates for PBR?	

DIRECT TESTIMONY OF BRUCE R. OLIVER
DCPSC Formal Case No. 1139

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive Fairfax Station, Virginia, 22039.

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

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I appear on behalf of the Apartment and Office Building Association of Metropolitan Washington (AOBA).

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

A. The purpose of my testimony in this proceeding is to provide the Commission with greater perspective regarding a number of key elements of the rate increase request and proposals for tariff changes that the Potomac Electric Power Company (hereinafter "Pepco" or "the Company") has presented in this proceeding. This testimony addresses numerous elements of the Designated Issues set forth in Attachment A to Order No. 18550, including the Commission's Designated Issue Nos. 1, 2.a., 3, 3.a., 4, 4.a., 4.b., 4.c., 4.d., 6, 6a, 7, 10, 10.a., 10.b.,10.d., 10.e., 13, 13a, and 19. This testimony also responds to portions of the pre-filed direct and supplemental direct testimonies of Pepco witnesses McGowan, Verner, Hevert, Ziminski, Nagle, Janocha, Lefkowitz, White, Hall, and Chamberlin.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I am an economist specializing in the areas of utility rates, energy, and regulatory policy matters. I have over 40 years experience in the analysis of energy and utility policy issues. That experience includes employment in management positions in the rate departments of two major utilities (the Pacific Gas and Electric Company and the Potomac Electric Power Company), as well as service in management and senior staff positions for three consulting firms, Revilo Hill Associates, Inc., the Resource Dynamics Corporation, and ICF Incorporated.

As a consultant, I have served a diverse group of clients on issues encompassing a wide range of energy and utility related activities. My clients have included state regulatory commissions, utilities, state Attorneys General, state- funded consumer advocacy groups, municipal governments, federal agencies, commercial and industrial energy users, hospitals and universities, suppliers of equipment and services to utility markets, residential consumer intervenors, the Electric Power Research Institute (EPRI), and the World Bank.

Projects for those clients have included work on gas, electric, water, and wastewater utility regulatory proceedings, as well as analyses and forecasts of supply, demand, and prices for utility and non-utility energy markets. I have also assisted a number of commercial, institutional, and industrial energy users in the negotiation of a wide range of energy service contracts, including contracts for the procurement of competitive electricity and natural gas services.

To date, I have presented more than 400 separate pieces of testimony in over 250 proceedings before regulatory commissions in 24 jurisdictions. The regulatory jurisdictions in which I have testified include: the states of Pennsylvania, New York, New Jersey, Maryland, Delaware, Virginia, North Carolina, Rhode Island, Vermont, Connecticut, Massachusetts, Ohio, Illinois, Wisconsin, Arizona, New Mexico, South Dakota, and California, Guam, the Virgin Islands, the District of Columbia, the City of Philadelphia, the Provence of Alberta, Canada, and the U.S. Federal Energy Regulatory Commission (FERC). My testimonies in those jurisdictions have addressed such topics as industry restructuring, utility mergers and acquisitions, divestiture of generation assets, sighting of energy facilities, utility revenue requirements, capital structure, costs of capital, cost of service allocations, rate design, rate unbundling, incentive ratemaking, revenue decoupling, capacity expansion planning, asset management, outsourcing, demand-side management, energy conservation, contracts for non-tariff service provided to large energy users, natural gas purchasing practices, gas transportation service, natural gas processing, competitive bidding, economic development rates, load research, load forecasting, weather normalization, metering, fuel procurement, and fuel pricing issues.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes, I have appeared before this Commission in nearly every major electric and gas utility rate proceeding for more than 35 years. Pepco cases before this Commission in which I have participated include: Formal Case Nos. 759 (Phases I, II, and III), 785, 813 (Phases I and II), 834, 869, 889, 939, 945, 951, 1002, 1053, 1053 Phase II, 1076, 1087, 1103, 1116, 1119, and 1121. I have also testified in nearly every major Pepco rate proceeding before the Maryland Public Service Commission ("MDPSC") since 1980, including the Pepco-Exelon Merger proceeding in Maryland, and Pepco's recently decided Maryland base rate case, Case No. 9418.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, it was.

II. SUMMARY

Q. WHAT IS YOUR OVERALL ASSESSMENT OF PEPCO'S FILING IN THIS PROCEEDING?

A. The $82.1 million or 22.72% overall revenue increase that Pepco seeks in this proceeding[1] represents a substantial burden for all District of Columbia rate-payers and warrants this Commission's thorough scrutiny. It is understood that the provision of safe and reliable service has its attendant costs. However, the magnitude of the increases that Pepco seeks in this proceeding, combined with the prospect of additional rate increase requests in the next few years, necessitates a careful review of the reasonableness and necessity of all elements of the Company's revenue increase request in this proceeding.

Pepco's filing in this case, once again, suggests that Pepco has stretched its imagination to inflate its size of its request. At a time when financial markets have been relatively stable, and there is no dramatic upward trend in allowed rates of return for utilities, the Company seeks an ROE that is 120 basis points above its currently authorized 9.40% ROE. In addition, Pepco's claimed test year O&M expenses include significant non-recurring billing system expenditures and other significant unexplained and unjustified expense increases.

Particularly important considerations in this case relate to the manner in which the Company's requested increase in this case would be distributed

[1] The Company's Application, filed on June 30, 2016, sought an overall increase in its distribution base rate revenue of $85.5 million or 23.65%. The request was reduced to $82.119 million in the Company's October 14, 2016 Supplemental Direct Testimony. See Exhibit Pepco (2B), page 1, lines 15-19.

among rate classes and among customers within each rate class. In this context, the Commission needs to focus on the intersection of: (1) the Company's requested revenue increase in this case; (2) Pepco proposed plan for elimination of negative rates of return for residential service; and (3) the Company's proposal for utilization of Base Rate Credits and Incremental Revenue Offsets. This testimony shows that Pepco's proposals for addressing each of these issues are inappropriate and will fail to achieve their purported objectives. Furthermore, in a case in which Pepco claims to offer a plan for eliminating negative class rates of return, the Company's proposal to apply less than an average percentage increase on classes with negative rates of return cannot be justified. As explained herein, Pepco's plan for eliminating negative rates of return and narrowing differences in class rates of return is poorly conceived and destined to fail, as have Pepco's prior efforts to address negative residential rates of return.

With the availability of substantial Base Rate Credits and the possibility of Incremental Offsets, this Commission has more options that usual in this case to move aggressively toward narrowing large existing differences in class rates of return. Yet, the Company's proposal squanders those resources to achieve greater temporary benefits for classes of customers that presently carry none of the burden of the returns required on the Company's rapidly growing rate base. These are not just issues about interclass subsidies. Rather, they are key elements of a potential utility "death spiral." As the costs of alternatives to utility supplied services become increasingly more economic, further increases in C&I

rates will simply push greater numbers of C&I customers to the point where renewables, self-generation, and improved energy efficiency are serious options to continued reliance on utility services. Already some of the largest users of electricity in the District of Columbia have installed, or are in the process of installing Combined Heat and Power facilities, and those installations negatively impact units of service over which Pepco can recover its costs of service. As billable units of service shrink, increases in costs for the remaining C&I customers will push greater numbers of those customers to make similar investment decisions. Moreover, subsequent efforts to increase rates for non-residential customers to compensate for further service lost to self-generation, renewables, and improved energy efficiency will simply escalate the process making alternatives to utility service more economic to another tier of customers.

In this context, Pepco's proposed distributions of its revenue increases and Base Rate Credits among rate classes in this proceeding can only be viewed as counterproductive. The Company's proposals also are inconsistent with this Commission's findings in several recent proceedings, including, but not limited to Formal Case No. 1119 and Formal Case Nos. 1103 and 1087. Although the Commission expressed its assessment that all customers should participate in the benefits of the Merger, Pepco's proposals attribute no direct merger benefits to the non-residential customers who bear the entire burden of the Company's return requirements plus subsidies to offset negative residential contributions to Pepco's required returns. The only Merger-related benefits distributed to Pepco customers in the District of Columbia to date have all been credited exclusively to residential Rate R and Rate AE customers, even though those classes have now been shown in at least four successive base rate proceedings to provide negative contributions to the Pepco's required returns on invested capital.

In this case, the Commission has also found the necessity of designating issues regarding the need for revision or termination of Pepco's BSA mechanism. Although the issues associated with Pepco's BSA may have had their origin in changes in customer counts associated with Pepco's implementation of a new billing system, this testimony demonstrates that concerns relating to the just and reasonableness of that mechanism and its interface with the establishment of Pepco's base rate are much broader in scope. If continuation of Pepco's BSA is to be entertained the BSA-related issues addressed herein need to be explicitly addressed and resolved.

Finally, in Issue No. 19, the Commission has asked the parties to address questions relating to whether alternative ratemaking structures warrant further investigation by this Commission. Pepco has given the Commission a decisive answer to that question in the formulation of its rate increase request in this proceeding. By submitting an obviously inflated revenue increase request, the Company has signaled that regular close scrutiny of the Company's costs and revenues is necessary to ensure that interests of District ratepayers are protected from waste and abuse in the rate setting process. Although fewer rate cases may suggest savings to ratepayers as a result of reduced regulatory expenses, ratepayers must be provided reasonable confidence that cost increases passed to consumers through alternative ratemaking structures would not exceed just and reasonable levels. To date, Pepco's track record does not provide such confidence.

In each of Pepco's base rate cases since its merger with Conectiv (roughly 15 years ago), the difference between the level of Pepco's initial rate increase request and the increase ultimately judged appropriate for the Company by this Commission has been more than sufficient to justify to costs of litigating each case. Thus, a pre-requisite for greater reliance on alternative ratemaking methods should be a demonstration that the Company only requests revenue increases that it can fully or nearly fully justify when subjected to scrutiny by the Commission and other parties. As this testimony demonstrates, the Company has fallen well short of that mark in this proceeding.

Alternative ratemaking methods, if well-structured and implemented with appropriate regulatory oversight may facilitate the achievement of certain regulatory objectives, and should not be viewed as a replacement for continued regulatory scrutiny of utility activities. Moreover, alternative ratemaking methods are not a cure-all for existing ratemaking problems, and can require substantial on-going review and monitoring to ensure that their structures and performance remain consistent with appropriate regulatory objectives in an evolving economic, political and social environment.

Q. PLEASE SUMMARIZE THE KEY ELEMENTS OF YOUR FINDINGS WITH RESPECT TO PEPCO'S PROPOSALS IN THIS PROCEEDING.

A. Key findings from my review of Pepco's filing in this proceeding include the following:

Costs of Capital and Capital Structure *(Issue No. 3)*

- Pepco's cost of equity recommendation significantly overstates the appropriate cost of equity for Pepco's distribution utility operations.

- The cost of equity analyses that witness Hevert presents in this proceeding are not properly developed to produce estimates that reflect investment risk comparable to that for Pepco's distribution utility operations.

- Nothing in U.S. capital markets or in Pepco's operations has changed so dramatically since Formal Case No. 1103 that warrants the rather substantial increase in Pepco's authorized ROE that the Company seeks in this proceeding.

Pepco's BSA Mechanism *(Issue No. 4)*

- Pepco's BSA mechanism presently incorporates a number of deficiencies that erode the reasonableness, credibility, and equity of the Company's computed monthly rate adjustments.

- The measures of actual numbers of customers that Pepco used following the start-up of its new SolutionOne billing system mis-represent the actual numbers of customers upon which monthly authorized revenue by class should have been determined.

- The forecasted monthly kWh by rate class that Pepco has used to compute monthly rate adjustments do not exhibit the characteristics of forecasted **normal weather** service requirements.

- The observed variations in the forecasted monthly kWh that Pepco has used to compute monthly rate adjustments by rate class raise serious concerns regarding the manner in which the Company's measures of forecasted kWh are determined.

Reflection of Merger Commitments *(Issue Nos. 10, 10a, and 10b)*

- Given that no Merger-related synergy savings are reflected in Pepco's test year costs of service, no provision for the Company's recovery of Costs to Achieve its Merger with Exelon is appropriate in this proceeding.

- Establishment of a regulatory asset for Pepco's recovery of Costs to Achieve the Merger is not justifiable unless the Commission can confidently conclude that it is **probable** that demonstrated Merger-related savings will exceed the Costs to Achieve that Pepco seeks to recover.

- The commitment of Exelon and its affiliates to future charitable contributions in the District of Columbia is not appropriately reflected on Pepco's books as a regulatory liability.

Revenue Increase Distribution *(Issue No. 13),* Pepco's Plan to Eliminate Negative Class RORs *(Issue No. 13a)*, Application of Base Rate Credits *(Issue No. 10d)*, and Proposed Use of Incremental Offsets (Issue No. 10e)

- Pepco's Rate Schedules R and AE continue to provide negative rates of return, and those rates of return are even more negative than in the Company's last case.

- Residential Rate R and Rate AE customers have not contributed anything to Pepco's return on its investment in facilities required to serve those customers for at least a decade (i.e., dating back to at least Formal Case No. 1016).

- Pepco's proposal, to place less than the jurisdictional average increases on the revenue requirements of its Residential Rate R and Rate AE customers, is not reasonable or justifiable.

- Pepco's Plan to eliminate negative rates of return over three cases ignores the potential, if not likelihood, of further slippage in Residential Class rates of return that will necessarily result from the Company's DCPLUG program.

- Pepco's proposed use of Base Rate Credits to offset all residential rate increases through February or March 2019 is poorly conceived and cannot be relied upon to accomplish that objective.

- Pepco's proposed use of Base Rate Credits to offset residential rate increases denies Commercial customers (who pay the Company's entire return on invested capital) any direct Merger-related benefits.

- The Merger-related Base Rate Credits should be used to offset the portions of approved rate increases by rate class that exceed the overall average increase percentage that results from the Commission's revenue requirements determinations.

- The Incremental Revenue Offsets referenced in the settlement of Formal Case No. 1119 are not necessary and should be avoided.

- The only benefit of the proposed Incremental Offsets is to possibly aid the achievement of a goal that in reality is most likely unattainable.

- If Pepco's plan to fully offset all revenue increases for residential customers through February 2019 is pursued, Residential customers in the District will face extremely large effective rate increases when the Merger-related Base Rate Credits and Incremental Revenue Offsets are exhausted.

- The magnitude of the combined revenue deficiencies for Rates R and AE has grown significantly between rate cases.

Revenue Requirements *(Issue Nos. 2a, 6 and 7)*

- Pepco's efforts to develop normal weather billing determinants for the test year do not properly compute kWh by rate block for rate classes having blocked kWh charges.

- Pepco has not reflected the impacts of its normalization of test year billing determinants on expected revenues at present rates.

- In the absence of the evidence of the achievement of actual synergy savings in excess of Pepco's claimed costs associated with achievement of the merger of Exelon and PHI, no authorization of recovery of costs to achieve that merger is appropriate in this proceeding.

- Pepco provides no justification for large increases in its claimed test year expenses for a number of its operating expense accounts.

- Pepco has inappropriately included non-recurring transition costs associated with the implementation of its new billing system in its on-going test year expenses.

- To the extent that billing system costs are deemed to be reasonable and appropriately-incurred billing system transition costs, those costs should be removed from Pepco's on-going operating expenses and amortized over a period of not less than 5 years starting from the initial activation of the Company's new billing system in January 2015.

Alternative Ratemaking Structures *(Issue No. 19)*

- Any effort to move toward the adoption of alternative ratemaking structures is inappropriate if it inhibits efforts to timely address the current unacceptably wide disparity in class rate of return in the District and/or the elimination of negative class rates of return.

- Performance Based Ratemaking generally provides greater expected benefits to the utility than its ratepayers.

- The adoption of ranges of authorized return is unnecessary and unjustified.

- Without first establishing a clear track record regarding the Company's ability to reasonably forecast future service requirements and costs (a track record that does not presently exist), reliance on fully forecasted test year data is inappropriate.

- Given uncertainties regarding such factors as the direction of future grid modernization activities, it is inappropriate to assume that Pepco can reasonably forecast its future service requirements and costs.

- Although substantial value may be extracted from the efforts of other jurisdictions and utilities to address Standby rates, Back-up rates, and related regulatory policy issues, policies adopted for the District of Columbia should be tailored to reflect the energy policy goals of the District and the current, and expected future, attributes of Pepco's distribution system in the District.

- Policies adopted to support the offering of Back-up and/or Standby services must consider the impacts of such policies on the maintenance of competitive retail energy markets and should not result in the re-introduction of Pepco's offering of bundled electric utility services.

- Careful consideration must be given to the appropriate role of competitive service providers in the provision of Standby and Back-up services.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR COMMISSION ACTIONS WITH RESPECT TO PEPCO'S FILING IN THIS PROCEEDING?

A. Based on the findings in this presentation, I urge the Commission to take the following actions:[2]

Costs of Capital and Capital Structure *(Issue No. 3)*

1. The Commission should reject the Company's requested 10.60% ROE in this proceeding as not reflective of returns for investments having risk comparable to that for Pepco's distribution utility operations.

[2] Omission from this list of a recommendation presented elsewhere in this testimony is unintentional and does diminish or negate the importance of a recommendation not included in this list.

2. The Commission should authorize a ROE for Pepco of **9.25%** and an overall rate of return for the Company of not greater than **7.31%**.

3. The Commission should monitor the relationship between Pepco's authorized rate of return and Exelon's DCF rate of return.

Pepco's BSA Mechanism *(Issue No. 4)*

4. The Commission should either take steps to remedy problems associated with Pepco's existing BSA mechanism or terminate the Company's use of that mechanism.

5. If Pepco's BSA is to be continued, the Commission needs to take several steps to improve the reasonableness of monthly rate adjustments that result from that mechanism.

6. The Commission should require a detailed audit of Pepco's crediting of revenue by rate class in the initial months of its new billing system operations starting with January 2015.

7. If Pepco's BSA is to be continued, the Commission should require that the Count of Contracts data Pepco employs in the design of

rates and development of BSA revenue targets is also used in the computation of Pepco's monthly BSA rate adjustments.

8. The Commission should require Pepco to re-compute its authorized revenue by rate class for each month since the start-up of its new billing system for which measures of Active Billed Customers rather than Count of Contracts data were used and the Company should adjust its deferred balances accordingly.

9. The Commission should takes steps to ensure reasonable consistency in measures of kWh by rate class by month that Pepco uses to compute the cents per kWh charges applied by rate class each month.

10. The Commission should seek more appropriate reflection of BSA-related revenue adjustments to base rates in it's assessment of over- and under-collections of revenue by rate class.

Revenue Requirements *(Issue Nos. 2a, 6 and 7)*

11. The Commission should find that Pepco has not accurately computed its normal weather adjustments to test year billing deter-

minants and revenues for rate classes with blocked charges for kWh usage, and inappropriately assumes that weather-related changes in kWh use will impact usage in each rate block proportionately.

12. The Commission should require that Pepco's normal weather adjustments to test year billing determinants be reflected in the Company's computed revenues at present rates for the purpose of determining the Company's requirements of additional test year revenue.

13. The Commission should deny Pepco's request in this proceeding for recovery of costs to achieve the merger of Exelon and PHI.

14. The Commission should find that Pepco fails to identify, explain and justify significant increases in a number of its operating expense accounts.

15. The Commission should find that Pepco has inappropriately included non-recurring billing system transition costs in its test year expenses in this case as on-going operating expenses.

16. The Commission should direct Pepco to remove all non-recurring billing system transition costs from its test year expenses and amortize those costs over a five year period starting in January 2015 (i.e., the month in which the Company's new SolutionOne system was first used to bill customers).

17. The Commission should limit Pepco's recovery of rate case expenses for this proceeding and all subsequent proceedings in a manner that reflects the proportion of the Company's overall revenue increase that the Commission ultimately finds to be justified for implementation.

Rate Impacts *(Issue Nos. 13, 13a, 10d and 10e)*

18. The Commission should find that Pepco's plans for the elimination of negative rates of return and utilization of Base Rate Credits and Incremental Offset are inappropriate and unrealistic.

19. The Commission should use Base Rate Credits for two purposes: (a) to offset rate increases in excess of the system average increase; and (b) to provide for improved customer service to Pepco's Non-Residential customers in the District.

20. The Commission should seek to avoid the need for Incremental Offsets; and if any Incremental Offsets are used, the costs of those offsets should be borne by the class or classes receiving direct benefits from those offsets.

Alternative Ratemaking Methods *(Issue No. 19)*

21. The Commission's consideration of alternative ratemaking methods should not precede determinations in Formal Case No. 1130 regarding the scope and direction of efforts to modernize Pepco's distribution system in the District.

22. The Commission should find that existing negative class rates of return and large differentials in existing class rates of return represent major impediments to the implementation of alternative ratemaking methods for Pepco.

23. The Commission should ensure that any steps taken toward the adoption and implementation of alternative ratemaking methods do not impede achievement of the Commission's goals of eliminating

negative class rates of return and narrowing differences in class rates of return.

24. The Commission should conclude that alternative ratemaking methods are not a replacement for continued regulatory oversight and regular substantive input to the regulatory process by customer representatives.

25. The Commission should conclude that the development and implementation of well-considered stand-by and back-up rate policies should be pursued, but the complexity of the operational, cost-of-service, ratemaking, and regulatory policy issues associated with such rates is not likely to be readily accommodated in a base rate proceeding.

III. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES RELATING TO PEPCO'S FILING IN THIS PROCEEDING ORGANIZED?

A. This discussion of issues is presented in six sections. **Section A** addresses Pepco's cost of equity and its overall costs of capital. **Section B** investigates the historical operation of Pepco's Bill Stabilization Adjustment ("BSA") mechanism, the current attributes of that mechanism, and appropriate steps for the Commission in its efforts to remedy problems identified in the current operation of that mechanism. **Section C** evaluates elements of Pepco's requested revenue requirement determinations in this proceeding and recommends certain adjustments to Pepco's test year costs and revenues. **Section D** provides an integrated assessment of (a) Pepco's proposed plan to eliminate negative rates of return; (b) the Company's proposed distribution of its requested revenue increase in this proceeding; and (c) Pepco's proposed use of Base Rate Credits and Incremental Offsets. **Section E** considers issues relating to the appropriate reflection of the Merger in this proceeding. Finally, **Section F** responds to elements of the Commission's designated Issue No. 19 and appropriate approaches to the Commission's consideration of alternative ratemaking methods.

A. PEPCO'S COST OF CAPITAL

Q. WHAT ARE THE MAIN ELEMENTS OF YOUR DISCUSSION OF COST OF CAPITAL ISSUES?

A. This section of my presentation addresses several key elements of Pepco's cost of capital presentation in this proceeding. Those elements include: (1) Pepco's Cost of Equity; and (2) Pepco's Overall Cost of Capital.

Q. DO YOU ACCEPT THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. Pepco's proposed capital structure in this proceeding is reasonably similar to the capital structure the Commission accepted in Formal Case No. 1103. Based on my review of the Commission's capital structure determination in Formal Case No. 1103, I find no need for future challenge of the Company's proposed capital structure in this proceeding.

1. Cost of Equity

Q. WHAT RATE OF RETURN ON COMMON EQUITY ("ROE") DOES PEPCO SEEK IN THIS PROCEEDING?

A. Pepco has requested a ROE of **10.60%.** Witness Hevert testifies that his recommended ROE range is actually 10.00% to 10.65, and his 10.60% recommendations is near the high end of that range. This contrasts with Witness Hevert's position in Formal Case No. 1103. In that case Witness Hevert advocated a ROE range of 10.25% to 11.00%, but he recommended the Commission adoption of a ROE at the low-end of his recommended ROE range.

The Company's requested ROE is noticeably above the **9.40%** ROE that this Commission granted Pepco in Formal Case No. 1103.[3] It also represents a marked increase over the 10.25% ROE the Company requested in Formal Case No. 1103.

[3] Order No. 17424, page 224, paragraph 566.hh.

Q. SHOULD THE COMMISSION ACCEPT WITNESS HEVERT'S ROE RECOMMENDATION?

A. No. The 10.60% ROE that he supports is well above the cost of equity that Pepco requires for its comparatively low-risk distribution utility operations. Witness Hevert's analyses and rationales do not properly consider the comparative risk of Pepco's distribution utility operations. Instead, his 10.60% ROE recommendation is driven by the results of scenarios that generally reflect return requirements for higher risk investments. Where Witness Hevert's recommendation suggests the need for a significant 120 basis point upward adjustment to Pepco's current authorized ROE, my analyses indicate that at least a 15 basis point reduction to Pepco's currently authorized ROE is appropriate.

Q. WHAT METHODS ARE USED BY WITNESS HEVERT TO ESTIMATE THE COST OF EQUITY FOR PEPCO'S DISTRIBUTION UTILTY OPERATIONS?

A. With one exception the ROE estimation methods that Witness Hevert employs in this proceeding are essentially the same as those he presented for the Company in Formal Case No. 1103. His methods include Discounted Cash-Flow ("DCF") analyses, Capital Asset Pricing Model ("CAPM") analyses, and Bond Yield Plus Risk Premium analyses. The one exception is that his Discounted Cash-Flow analyses now include use of both Constant Growth and Multi-Stage DCF models.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE MULTI-STAGE DCF ANALYSES THAT WITNESS HEVERT PRESENTS?

A. Yes. Witness Hevert's Multi-Stage DCF analyses add little of value to the discussion of Pepco's equity return requirements. As noted in witness Hevert's response to AOBA Data Request 9-11b in Formal Case No. 1137 currently pending before this Commission, "*Mr. Hevert does not state anywhere in his testimony that his multi-stage model is an improvement over the constant growth DCF model*." Moreover, the 55 pages of Witness Hevert's Exhibit Pepco (D)-2 are testament to the vast amounts of forecasted data and assumptions on which an analyst, such as Witness Hevert, must rely to compute estimates of Multi-Stage DCF returns. The speculative assessments of future cash-flows upon which such Multi-Stage DCF analyses depend are not discernibly more accurate or reliable than the assumptions upon which Constant Growth DCF analyses are premised, and therefore provide no greater insight regarding Pepco's equity return requirements. In this context, Witness Hevert's complex and data intensive Multi-Stage DCF analyses deserve little weight in the Commission's cost of equity determinations in this proceeding.

Q. DO YOU CHALLENGE THE PROXY GROUP THAT WITNESS HEVERT EMPLOYS FOR ROE ESTIMATION PURPOSES IN THIS PROCEEDING?

A. Given the current structure of the industry, issues associated with proxy group selection have become less important than questions regarding the manner in which proxy group results should be adjusted to develop reasonable and appropriate estimates of equity return requirements for distribution utility operations. The fact is that mergers and acquisitions within the industry have left few, if any, pure distribution utility operations for which market-based observations are available.[4] Thus, proxy groups used in cost of equity analyses must rely primarily if not exclusively on data for holding companies, many of which own substantial non-utility operations and/or have considerable investment in integrated utility operations. This is true of most if not all of the 22 companies in the proxy group that Witness Hevert employs in this proceeding.[5]

Q. DO ANY OF THE COST OF EQUITY ANALYSES THAT WITNESS HEVERT PRESENTS DEPICT THE RISK AND RETURN REQUIREMENTS OF PEPCO'S DISTRIBUTION UTILITY OPERATIONS?

A. No. All of Witness Hevert's analyses are premised on either analyses of holding company data or general market data that are presented without any effort to address the relationship between Pepco's distribution utility risk and return requirements and those of the companies or markets for which cost of equity estimates are developed. Importantly, Witness Hevert fails to address the

[4] Pepco Witness Hevert recognizes this fact at page 14, lines 8-10, of his Direct Testimony, Exhibit Pepco (D), and then concludes that reliance on vertically integrated electric companies is reasonable without addressing any impacts of the differences between vertically integrated electric companies and "pure play" distribution utilities. This is like substituting a bulldog for a blood hound in a fox hunt and assuming both will have the same hunting abilities. There is a difference between accepting that we must rely upon a less than representative proxy group and assuming that use of such a group will have no impact on the direct applicability of resulting cost of equity estimates.

[5] See the companies included in Exhibits Pepco (D)-1, (D)-2, (D)-4, (D)-7 and (D)-8.

generally higher risk nature of holding company operations and investment activities and the operations of integrated utilities with substantial investment in generation assets. During the Exelon-PHI merger proceedings in Maryland and before this Commission, AOBA documented the differences in rating agency assessments of credit ratings for distribution utilities and their parent companies noting that in numerous instances the credit rating of the distribution utility was adversely impacted by the credit rating of the parent. A key objective of ring-fencing the PHI utilities was to protect them from adverse impacts of the holding company on their finances and credit ratings. The Company's cost of equity analyses in this proceeding are presented as if ring-fencing does not exist and the risk and return requirements of holding companies are the same as those for Pepco.

Q. DOES WITNESS HEVERT'S USE OF BETA COEFFICIENTS IN HIS CAPM ANALYSES ACCOUNT FOR DIFFERENCES IN RISK AND RETURN REQUIREMENTS BETWEEN DISTRIBUTION UTILITY OPERATIONS AND THOSE FOR THE BROADER MARKET FOR EQUITY SECURITIES?

A. No. Witness Hevert's use of "Beta Coefficients" may provide a partial indication of differences in risk and return between the utility holding companies that comprise his proxy group and the risk and return requirements of the general market for equity securities, but they do not assess differences in risk and return requirements between a distribution utility, such as Pepco, and those for the utility holding companies that comprise his proxy group.

Beta Coefficients are intended to measure the volatility in the price of a stock relative to the overall price volatility in the stock market. As such the Beta Coefficients only provide an indication of one type of risk that investors may face (i.e., stock price volatility). Measures of Beta can vary noticeably depending on the time period over which stock price volatility is observed. (This difference is the primary source of differences between the Value Line and Bloomberg measures of Beta that Witness Hevert employs).[6] This Commission has previously expressed its concerns regarding the limitations of Beta coefficients. Specifically, the Commission has found "*the use of betas as the single predictor of comparable risk for long-term investment to be too simplistic*."[7] That finding is equally applicable to witness Hevert's use of Beta coefficients in his CAPM analyses in this proceeding.

Finally, the problems associated with reliance on Beta Coefficients as measures of differences in risk have another another dimension. Since Pepco has no publicly traded stock, we no longer have the ability to assess either the relative price volatility that Pepco-issued stock would experience in the market place or differences in the price volatility of Pepco stock versus the price volatility of holding company equity issues. In other words, there is no current information

[6] As stated at page 31, lines 17-19, of Witness Hevert's Direct Testimony, "*Value Line calculates the Beta coefficient over a* ***five-year period****, whereas Bloomberg's calculation is based on* ***two years*** *of data*." (Emphasis Added.)
[7] Order No. 17132, paragraph 46, pages 19-20.

regarding the relative price volatility of equity investments for Pepco's distribution utility operations. This is a problem that utility regulators must not ignore in their efforts to determine appropriate measures of equity return requirements for distribution utilities that do not issue publicly traded stock.

As AOBA demonstrated in the Exelon – PHI merger proceedings,[8] distribution utility risks are generally less than those for more diversified utility holding company operations. In the case of Exelon's acquisition of Pepco, it is clear that a key element of the attractiveness of Pepco's utility operations to Exelon was the perceived ability of Exelon to use more predictable utility earnings to offset variability in the earnings of Exelon's non-regulated generation and wholesale energy marketing activities. Thus, there is substantial evidence that the appropriate Beta coefficient for assessing Pepco's relative risk (based on market price volatility considerations) should be lower than that for Exelon or other more diversified utility holding companies. Yet, witness Hevert's present-ation in this proceeding ignores those risk differentials.

Q. DO WITNESS HEVERT'S BOND YIELD PLUS RISK PREMIUM ANALYSES EXHIBIT SIMILAR PROBLEMS WITH RESPECT TO ASSESSING RETURNS FOR COMPARABLE RISK INVESTMENTS?

A. Yes, they do. The regression equation Witness Hevert relies upon to estimate equity returns under that methodology are, once again, derived from market

[8] Formal Case No. 1119 before this Commission and Case No. 9361 before the Maryland Public Service Commission.

observations which have no demonstrated ties to the risk and return requirements of Pepco's distribution utility operations. Moreover, unlike the CAPM method which at least made some attempt to account for risk and return differences between Witness Hevert's proxy group and the general market, his Bond Yield Plus Risk Premium includes no explicit risk adjustment factor. Rather, the implicit assumption in Witness Hevert's Bond Yield Plus Risk Premium methodology is that all utilities, both today and in the past, represent a common level of risk. This ignores the rather dramatic changes that have occurred within the industry since 1980, including but not limited to, the unbundling of utility services and the substantial consolidation that has occurred within the industry as a result of mergers and acquisitions. As a result of these changes there are now more significant differences in risk and return requirements for fully unbundled distribution utilities and for integrated electric utility operations. It is also inappropriate to compare the risk and return relationships for companies that operated in the 1980s and early 1990s and companies that operate on an unbundled basis in today's markets.

Q. DO YOU HAVE ANY FURTHER CRITICISMS OF THE COST OF EQUITY ANALYSES THAT PEPCO WITNESS HEVERT PRESENTS?

A. Yes. The 30, 90, and 180 trading day measures of stock price that Witness Hevert employs in his DCF analyses are not reflective of the measures of stock price on which investors typically rely in their assessments of dividend yields, and should be viewed cautiously by this Commission. The 30-trading day, 90-trading day, and 180-trading day periods that he employs do not correspond to one-month, three-month and six-month calendar periods. Rather, his 30 trading day period represents a period that runs approximately one and a half months. His 90 trading day period covers a period of about four and a half months, and his 180-day period covers a little less than nine months of trading activity. These are not periods typically used by investors to evaluate dividend yields or stock price performance, and Witness Hevert offers no compelling argument for why his chosen stock price averaging periods are appropriate substitutes for averaging investors and analysts more typically reference.

Witness Hevert explains that he employs those three measures of average stock price purportedly to balance concerns regarding: (1) the potential that results might be skewed by anomalous events; and (2) the desire to produce results that are "*reasonably representative of expected capital market conditions over the long term*."[9] However, the averaging periods he employs accomplish neither of those objectives. The more traditional approach is to use stock prices averaged over an annual period. Witness Hevert's use of shorter averaging periods provides no protection against the inclusion of anomalous data within his averages. Rather, shorter stock price averaging periods actually expose his analysis to greater risk that the stock prices during those periods are not reflective of longer-term assessments of stock prices for the companies included

9 The Direct Testimony of Pepco witness Hevert at page 18, lines 22, through page 19, line 3.

in his proxy group. The use of shorter averaging periods actually increases the potential that the resulting average is dominated by a comparatively short-lived market surge or down turn that is not reflective of longer-term market price expectations.

Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY FOR PEPCO IN THIS PROCEEDING?

A. I recommend that the Commission authorize a return on equity ("ROE") for Pepco of **9.25%**. That recommendation represents the average of my DCF and CAPM results. Overall my DCF and CAPM results portray a range from 9.03% to 9.77%. While the mid-point of that range is 9.40%, I urge the Commission to adopt my 9.25% recommendations as a reflection of the lower risk of Pepco's distribution utility operations relative to the overall risk of the holding companies that comprise the proxy group.

Q. HOW DID YOU ARRIVE AT YOUR ROE RECOMMENDATION?

A. The analysis for my ROE recommendation in this proceeding is presented in Exhibit AOBA (A)-1. As shown in that exhibit, the ROE that I recommend is based on a combination of the results of DCF and CAPM analyses. Page 1 of Exhibit AOBA (A)-1 provides a summary of the analyses underlying my cost of equity recommendation. Supporting detail for my DCF analysis is found in page

2 of Exhibit AOBA (A)-1. Pages 3 and 4 of Exhibit (A)-1 set forth the data and computations supporting my CAPM.

Q. IS THE PROXY GROUP THAT YOU USE IN YOUR DCF AND CAPM ANALYSES THE SAME AS THAT USED BY PEPCO WITNESS HEVERT?

A. It is with one exception. That exception is the exclusion of data for First Energy Corp. Recent earnings growth projections from each of the sources I have used (i.e., Zacks, CNN, and Yahoo) have reflected negative projected earnings growth rates for First Energy Corp, and on that basis I have judged that inclusion of First Energy Corp. would unnecessarily and inappropriately bias cost of equity estimates downward. With the exclusion of First Energy Corp., the proxy group still includes data for 21 companies, which is a rather sizable proxy group.

Q. IN YOUR CAPM ANALYSIS HOW DO YOU COMPENSATE FOR THE LACK OF MARKET DATA ON WHICH THE ASSESSMENT OF DIFFERENCES IN RISK AND RETURN REQUIREMENTS BETWEEN PEPCO AND THE PROXY GROUP AND/OR BETWEEN PEPCO AND THE GENERAL MARKET?

A. In the absence of publicly traded Pepco stock, differences in risk associated with stock price volatility are not observable. Witness Hevert attempts to address this problem by assuming that the risk of his proxy group companies can be differentiated from the general market through the use of Beta coefficients. I take a different approach, recognizing that appropriate Beta coefficients and/or other market-based measures of risk cannot be computed for a company that does not have publicly traded stock, I have elected to account for such risk differentials through adjustments to the assumed risk premiums. Although that may be a less elegant approach, it has produced ROEs that tend to be closer to commission approved ROEs than Witness Hevert's recommendations.

Q. DO YOU ANY FURTHER OBSERVATIONS REGARDING THE INFORMATION PRESENTED IN EXHIBIT AOBA (A)-1?

A. Yes. Page 2 of 4 in Exhibit AOBA (A)-1 includes computation of a DCF based cost of equity for Pepco's new parent company, Exelon Corp. of just 7.84%. The Commission should question why Witness Hevert represents that Pepco needs a 10.60% ROE when the computed DCF cost of equity for its parent company is only 7.84%. Although I believe most cost of equity witnesses and regulatory Commission's would be reluctant to advocate or approve a ROE for a regulated utility in the range of that computed for Exelon, I would encourage the Commission to monitor the relationship between Pepco's authorized ROE and Exelon's market-based DCF results. If the current relationship persists, the Commission may need to consider narrowing that difference in Pepco's next base rate case.

2. Overall Cost of Capital

Q. WHAT OVERALL RATE OF RETURN DOES PEPCO REQUEST?

A. Based on its requested **10.60%** ROE and the Company's proposed Capital Structure, Pepco Witness McGowan computes the Company's requested overall rate of return to be **8.00%.**[10]

Q. HOW DOES THE COMPANY'S REQUESTED OVERALL RATE OF RETURN COMPARE WITH THE OVERALL RATE OF RETURN APPROVED BY THE COMMISSION IN FORMAL CASE NO. 1103?

A. The Company's requested 8.00% ROR in this proceeding is 35 basis points above the overall rate of return authorized for Pepco in Formal Case No. 1103. That result is driven almost exclusively by the Company's requested increase in its ROE. Given that the Company's requested percentage of Common Equity is slightly (5 basis points) lower than the Commission approved in Formal Case No. 1103 and Pepco's cost rate for long-term debt has declined 48 basis points (i.e., from 5.96% to 5.48%), the sole driver of Pepco's requested increase in its overall rate of return is the 120 basis point increase that it seeks in its ROE.

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[10] Exhibit Pepco (B)-5, page 1 of 4.

Q. WHAT IS THE IMPACT OF YOUR ROE RECOMMENDATION ON THE OVER-ALL COST OF CAPITAL THE COMMISSION SHOULD APPROVE FOR PEPCO?

A. **Exhibit AOBA (A)-2** shows the calculation of an overall rate of return for Pepco with the ROE recommended herein inserted in the Company's requested capital structure. As shown in that exhibit, my ROE recommendation lowers the overall cost of capital for Pepco from the Company's request of 8.00% to **7.31%**.

Q. WHAT IS THE IMPACT OF YOUR ROR RECOMMENDATION ON PEPCO'S REVENUE INCREASE REQUEST IN THIS PROCEEDING?

A. Exhibit AOBA (A)-3 calculates the impact of AOBA's rate of return recommendations on Pepco's revenue increase request in this proceeding. As shown in that exhibit, the combination of AOBA's recommended cost of equity, and Pepco's capital structure lower the Company's revenue increase request in this proceeding by more than **$18.0 million**.

<u>B. PEPCO'S BSA MECHANISM</u>

Issue No. 4

Should Pepco's BSA Mechanism be continued and, if so, what changes to the mechanism, if any, are necessary and appropriate?

a. Has Pepco reasonably and appropriately developed the revenues per customer that will be used in BSA determinations subsequent to the conclusion of this proceeding?

b. If the BSA is continued, what forecasts of kWh per rate class should be used in the monetary computation of monthly rate adjustment ($/kWh)?

c. Are Pepco's test year numbers of customers and revenues developed in a manner consistent with the actual data presented in its BSA filings?

d. *How would the BSA mechanism be adjusted if MMA customer count changes from number of dwelling units to the number of buildings?*

Q. DOES PEPCO PROVIDE ANY EVIDENCE THAT ITS PURPORTED BILL STABILIZATION ADJUSTMENT ("BSA") HAS ACTUALLY SERVED TO STABILIZE BILLS FOR ITS DISTRICT OF COLUMBIA CUSTOMERS?

A. No. The Company's BSA actually serves primarily as a Revenue Assurance Mechanism ("RAM") for Pepco and could reasonably be re-labeled as such. The primary function of that mechanism is to ensure that Pepco is able to recover its authorized revenue requirements, as adjusted for numbers of customers, and the Company provides no support for a conclusion that its BSA actually provides direct and traceable benefits to its customers in the District.

Q. SHOULD PEPCO'S BSA BE CONTINUED?

A. Continuation of Pepco's BSA is not critical to the Company's ability to maintain the financial health of its District of Columbia operations. In that context, whether Pepco's BSA should be continued is a question that should be determined on the basis of how successfully the numerous problems associated with the mechanism can be resolved in this proceeding. When the Commission began its investigation of the Company's BSA mechanism, the focus of that investigation was primarily on the unexplained fluctuations in reported numbers of customers by rate class. However, as will be explained below, there are additional problems associated with Pepco's BSA that need to be addressed.

Q. WHAT ARE THE PROBLEMS IN PEPCO'S BSA THAT NEED TO BE RESOLVED?

A. This testimony identifies at least five problem areas with the current BSA rate adjustment process that need to be remedied. Those problems include:

(1) The current lack of consistency between BSA adjustment calculations and the Company's development of its proposed rate designs and BSA revenue per customer targets;

(2) The need for greater consistency in the manner in which the forecasted kWh used by the Company to compute monthly BSA rate adjustments are developed;

(3) Double counting of the influence of weather in the determination of base rate revenue requirements by class and the establishment of monthly BSA revenue targets;

(4) The need for modification of BSA determinations to address the establishment of a separate rate class for MMA customers;

(5) The need for a detailed audit of Pepco's crediting of revenues by rate class.

1. Customer Count Issues

Q. HAVE THE NUMBERS OF CUSTOMERS BY RATE CLASS THAT PEPCO USES IN ITS MONTHLY DETERMINATIONS OF "ALLOWED REVENUE" BY MONTH STABILIZED SINCE THE INITIAL IMPLEMENTATION OF PEPCO'S NEW BILLING SYSTEM?

A. No, they have not. Significant month-to-month fluctuations in the numbers of customers by rate class continue to be observed. Exhibit AOBA (A)-4 compares BSA reported numbers of customers for five of Pepco's largest classes in the District before and after the implementation of the Company's SolutionOne billing system. The data indicates that in the twelve-month period prior to Pepco's activation of its SolutionOne billing system no class had a differential between its maximum and minimum number of customers by month that was greater than 4% of the annual average number of customers for the class. However, in Post-SolutionOne Implementation periods, monthly variations in numbers of customers have increased dramatically. The Commission should understand that relative stability in annual averages means nothing. If the weighting of monthly authorized revenue per customer amounts for a class is skewed, then the accuracy of annual authorized revenues by class will be eroded and total authorized revenue requirements for the class on an annual basis will be misstated.

Q. IS THERE PRESENTLY ANY MECHANISM WITHIN THE MONTHLY BSA RATE ADJUSTMENT PROCESS FOR ADJUSTING THE COMPANY'S COMPUTATIONS OF "ALLOWED REVENUE" BY RATE CLASS?

A. The Company's monthly rate filings include a line (line 2.a. in Section I.A.) for the entry of adjustments, but such adjustments require manual input and are not automatic. Within the last year a couple of adjustments have been made to Residential revenue requirements, but none have been implemented for commercial customers.

Q. HAVE PEPCO'S TEST YEAR NUMBERS OF CUSTOMERS AND REVENUES BEEN DEVELOPED IN A MANNER CONSISTENT WITH THE DATA FOR ACTUAL NUMBERS OF CUSTOMERS PRESENTED IN ITS MONTHLY BSA FILINGS?

A. No. For the months of the test year, Pepco's monthly BSA filings have used measures of "Active Billed Customers," but its filings in this proceeding have relied on "Count of Contracts" data to represent the Company's numbers of customers for rate design and revenue determination purposes. Although Pepco has expressed a willingness to use its Count of Contracts data in monthly BSA filings going forward, it did not do so during the test year, and there is no indication that it has implemented such a change to date.

Q. WHY IS USE OF COUNT OF CONTRACTS DATA IN BOTH THE DEVELOPMENT OF BASE RATES AND THE COMPUTATION OF MONTHLY BSA IMPORTANT?

A. Proper development and adjustment of monthly authorized revenues requires that both monthly authorized revenues and adjustments to those revenues be developed on a consistent basis. The measures of Active Billed Customers that Pepco has used to adjust monthly authorized revenue for BSA purposes (since the introduction of its new billing system) do not provide such consistency. Instead, that data allows for distortion of the actual numbers of customers served. That, in turn, produces distortions of monthly authorized revenue levels by class as a result of the often unpredictable timing of billings and billing adjustments. If for any reason a customer is billed for multiple months of usage within a single month, the customer can be counted as multiple customers in that month, but may not be counted at all in other months.

Since the Company's revenue per customer targets are not uniform across the months of the year, a shift in the month in which a customer is recognized for billing purposes can impact the overall level of annual authorized revenue for which a class is held responsible through the BSA process. Furthermore, once an inappropriate adjustment to monthly authorized revenue for a class is folded into the Company's BSA deferred revenue accounting, there is no mechanism for ensuring that such a distortion is subsequently eliminated or offset by upward or downward adjustments to the recognized numbers of customers and computed "allowed revenue" in subsequent months. In other words, there is no process for reconciliation or removal of the distortions of authorized revenue by class that result from the Company's over- or under-representation of monthly numbers of customers for a class.

Exhibit AOBA (A)-4 depicts the considerable monthly fluctuations in measures of monthly numbers of customers by class that Pepco's transition to its SolutionOne Billing System and its concurrent shift to use of measures of Active Billed Customers have introduced in the BSA process. For each class shown, the volatility in reported numbers of customers over the course of a year has increased sharply. Prior to implementation of Pepco's new billing system, none of the classes shown had a difference between the high and low monthly numbers of customers of greater than 3.94%. Since January 2015 (the month in which the Pepco began using the SolutionOne system for billing retail customs), all but one of the classes for which data are presented Exhibit AOBA (A)-4 have significant double-digit ranges of variations in their reported numbers of customers. For the GT-3A class the observed variation in reported monthly customer counts grew from 3.5% of the average number of customers for the class in 2014 (i.e., prior to the start-up of the SolutionOne billing system) to 97.33% for calendar year 2015.

Even in 2016, the second year of the Company's use of the SolutionOne system, monthly fluctuations in the reported numbers of customers were unacceptably large. For the GT-3A class which is comprised of comparatively large accounts served at primary voltage, the difference between the number of customers reported by month has varied in 2016 (through October) from 132 customers to 198 customers. The buildings served by these accounts do not enter and leave the system on a frequent basis, and that type of variation is not at all indicative of the numbers of customers actually served on a month-to-month basis.

Given that this element of the BSA process is not subject to reconciliation to actual numbers of accounts served in each month, this level of variation is unacceptable. It also substantially erodes the reliability of Pepco's monthly calculations of "Allowed Revenue" by rate class. Since monthly "allowed revenue" determinations effectively alter the Commission's revenue determination in the Company's last base rate case, these computations warrant the Commission's close monitoring and should reflect a high level of precision. However, the actual accuracy of the current determinations must be questioned.

For example, witness Janocha's rate design exhibit in this proceeding shows 1,855 customer billing units for the GT-3A class during the test year, but the Company's monthly BSA filings reported "actual" numbers of customer months for that class totaling 1889 customer months, an increase of 34. Multiplying that increased number of customer billing units by the average allowed revenue per customer per month for the test year, I find that the BSA process overstated the test year revenue requirement for the GT-3A class by approximately **$902,000**. Moreover, that $902,000 amount not only increased the deferred revenue balance for the GT-3A class, it is also added to the revenue requirement for the GT-3A class that witness Janocha uses to compute charges at the Company's proposed rates. In other words, GT-3A customers are asked to both pay additional charges for erroneously computed "allowed revenue" amounts in the BSA process and inappropriate additional annual charges on an on-going basis under the Company's proposed rates. Furthermore, these inappropriate additional charges are over and above the Company's requested rate increase in this case and will not be mitigated in any way by a reduction of Pepco's requested revenue increase.

This problem does not appear to be unique to the GT-3A class. To varying degrees it can be expected to impact the accuracy of both BSA revenue adjustments for all classes for which monthly BSA rate adjustments are computed. Moreover, since the Company's rate design proposals adjusts class revenue requirements to reflect the BSA calculations of "Allowed Revenue" for the test year, the Company's proposed **base rates** for all BSA classes are affected by this problem.

2. BSA kWh Forecasts

Q. WHAT IS THE ROLE OF KWH FORECASTS IN THE COMPUTATION OF MONTHLY BSA RATE ADJUSTMENTS?

A. In the Company's monthly BSA filings, the amount of any revenue over- or under-collection for a class in the month just completed is divided by a forecasted measure of kWh for the month in which the rate adjustment will be applied. This calculation (subject to cap limitations) determines the dollars per kWh adjustment that is applied in the subsequent month.

Q. WHY ARE THE KWH FORECASTS PEPCO HAS USED IN ITS CALCUATION OF MONTHLY BSA RATE ADJUSTMENTS A MATTER ON WHICH THIS COMMISSION SHOULD FOCUS?

A. My review of the Company's BSA filings finds unexpected variations in the forecasted kWh that the Company uses to compute BSA dollars per kWh rate adjustments. Month-to-month variations in forecasted kWh for a class are to be expected. However, given that normal weather conditions should not change dramatically from year-to-year (particularly where normal weather is computed on the basis of 30-year average degree days), the monthly distribution of kWh from year-to-year should not reflect large fluctuations. Yet, my examination of Pepco's BSA forecasted kWh measures finds numerous large and unexplained variations in monthly measures of forecasted kWh that Pepco has used. These variations are documented in the pages of Exhibit AOBA (A)-5.

Q. WHAT SHOULD THE COMMISSION OBSERVE FROM THE DATA PRESENTED IN EXHIBIT AOBA (A)-5?

A. Each page provides a comparison of Pepco's forecasted kWh by rate class for the month of a calendar year with the comparable forecasts used by Pepco in its prior year's BSA filings. At the bottom of each page the percentage change in forecasted kWh from the same month of the prior year is computed for each rate class and month. The computed monthly changes often vary dramatically. For example page 1 of 6 in Exhibit AOBA (A)-5 compares the Company's BSA forecasts of kWh by month for calendar year 2016 with its forecasts of kWh by month from its 2015 BSA filings. For Pepco's Residential Rate R class, these comparisons show very irregular patterns of changes in monthly kWh. For the month of July the Company's 2016 kWh forecast for Rate R is 4.6% below its 2015 forecast for the same month. However, for August Pepco's 2016 forecast is 20.1% lower than its forecast for the same class for August of 2015. I also observe that for the RTM class we find that the Company's forecast is 17.6% lower in 2016 than in 2015 but for December 2016 the Company's forecasted RTM kWh are 8.4% higher than in the prior year. Forecasts developed on the basis of Normal Weather requirements should not be expected to display such irregular changes. The Commission should further note that for unexplained reasons Pepco elected to use the same forecasted kWh for all classes for the months of March and April of 2016 that it used for those months in 2015.

Additional comparisons are provided in Exhibit AOBA (A)-5 for changes in forecasted kWh by rate class by month for calendar years 2015, 2014, 2013, and 2012, and each year provides numerous examples of inexplicably large and/or irregular patterns of year-to-year changes in forecasted kWh by rate class by month. Greater than 10% changes (either increases or decreases) are highlighted. However, even among the changes of less than plus or minus 10% there are many instances in which observable changes still do not appear to constitute appropriate reflections of normal weather kWh usage patterns.

Q. WHAT MEASURES OF KWH BY RATE CLASS SHOULD BE USED IN THE COMPUTATION OF MONTHLY RATE ADJUSTMENTS IN TERMS OF DOLLARS PER KWH?

A. The kWh used in computing dollars per kWh by rate class should be reflective of normal weather kWh requirements. Moreover, to be consistent with the Commission's rate determinations, the normal weather kWh used for BSA rate adjustment calculations should be the same as those approved by the Commission in the Company's most recent base rate proceeding. Given the expectation that Pepco will be filing rate cases on a relatively frequent basis,[11] the Company's estimates of Normal Weather kWh requirements will be regularly updated. As a result, reliance on test year estimates of Weather Normal kWh are not likely to introduce variations in the Company's forecasted kWh by rate class that rival the magnitudes of the variations observable in Pepco's BSA filings. If, however, the Commission believes that more forward-looking estimates of kWh are necessary, then I would recommend that annual kWh by month for each rate class be adjusted in proportion to the Company's projected change in total annual kWh for the class. This presumes that normal weather conditions (i.e., the distribution of normal weather heating and cooling degree days by month) should not change significantly between rate cases.

3. Double Counting of Weather Impacts

Q. WHAT IS THE RELATIONSHIP BETWEEN PEPCO'S BSA RATE ADJUSTMENTS AND THE COMPANY'S EFFORTS TO REFLECT REVENUES AT PROPOSED RATES UNDER NORMAL WEATHER CONDITIONS?

A. The Company's adjustments for Normal Weather and its BSA rate adjustment process are at least partially duplicative.

The BSA is designed to compensate the Company for any fluctuations in its revenue collections. Only changes associated with additions or losses of

[11] Pepco's history suggests that it files rate cases at least every two to three years. However, the Company's capital spending plans and its representations in Formal Case No. 1119 suggest that more frequent rate case filings may be anticipated over the next several years.

numbers of customers are earmarked for separate consideration through adjustment of each class' monthly "Allowed Revenue." Whether changes in usage and billed revenue are the result of changes in the numbers of appliances, the configuration of appliances/facilities, energy conservation/energy efficiency programs, changes in customer work or vacation schedules, loss of tenants within commercial buildings, or variations in weather is not important for the determination of BSA rate adjustments. The BSA mechanism treats the effects of all such factors on billed revenue in a uniform manner. There is no current process for determining the portion of observed differences between Actual monthly billed revenue for a class and "Allowed Revenue" for the class that is attributable to weather as opposed to other factors.

Pepco's weather normalization of kWh, on the other hand, is intended to focus specifically on the effects of weather, as measured by Heating and Cooling degree days, on the Company's expected revenue collections. Yet, it is important to note, that my review of the Company's weather normalization methods finds nothing that identifies and segregates the effects on kWh use of factors other than weather. Thus, there is nothing that ensures that Pepco's weather normalization adjustments do not incorporate some measure of changes in kWh use that are not actually weather driven.

Q. HOW SHOULD THE COMMISSION ADDRESS THE OVERLAP IN THE COMPANY'S BSA AND REVENUE NORMALIZATION ADJUSTMENTS?

A. While I understand and support the Commission's efforts to set rates on the basis of normal weather, I encourage the Commission to find that efforts to include both BSA and Normal Weather adjustments in Pepco's development of proposed rates represents an inappropriate double counting of at least the weather-related portion of changes in usage by rate class. In this context, I recommend that the Commission should take two actions. First, it should require Pepco to net weather normalized adjustments to revenue by class against its "BSA/Revenue Annualization" adjustments to revenue requirements by rate class. Second, the Commission should require that the kWh measures that are used in the Company's determination of monthly dollars per kWh rate adjustments by class should be the same as those computed for base rate determinations.[12]

4. Assignment of Revenue by Rate Class

Q. HAS YOUR REVIEW OF PEPCO'S BSA IDENTIFIED ANY CONCERNS REGARDING THE MANNER IN WHICH REVENUES HAVE BEEN CREDITED TO RATE CLASSES SINCE THE COMPANY'S NEW BILLING SYSTEM WAS ACTIVATED?

[12] This assumes that the Commission can identify a set of normal weather kWh estimates that it finds reasonable and acceptable for ratemaking purposes. As explained further in my discussion of the Company's estimation of normal weather revenues in the next section of this testimony, there are significant problems in the data and methods Pepco has used to compute normal weather kWh in this proceeding that undermine the reliance on those estimates, particularly for several of Pepco's smaller classes of service in the District.

A. Yes, it has. In the early months of the Company's use of its new billing system there were a number of problems that surfaced. Although Pepco claims that most of those problems were resolved in subsequent months, I find reason to believe that certain revenues may not have been appropriately recorded by rate class. I also do not find any evidence of efforts to adjust or compensate for such concerns in subsequent months.

A key example relates to Company's commercial rate classes. In the cover letter accompanying Pepco's February 23, 2015 monthly BSA filing, the Company explicitly recognized that customer counts for January 2015 were "lower than normal," and it attributed those differences to:

(1) The new billing system shifted the posting of customers (and presumably revenues) associated with the Company's final billing cycle for each month to the next month (e.g., the final billing cycle for January 2015 was posted in February);

(2) A higher number of exceptions was found in the month of January due to new system implementation and some accounts with pending supplier charges. This also pur-

portedly caused the rendering of some bills to be delayed for a month or longer.[13]

Q. HOW DID THE IDENTIFIED PROBLEMS IMPACT REPORTED NUMBERS OF CUSTOMERS AND REPORTED REVENUES BY RATE CLASS?

A. In general both reported numbers of customers and reported revenues were noticeably lower for January 2015 than those reported for the preceding and subsequent months. Perhaps the most dramatic change was observed for the GT-3A class, where the reported number of customers for January 2015 was only 47 while in the prior 12 months that class was consistently reported as having between 143 and 149 customers. This is documented in Exhibit AOBA (A)-6, page 4 of 4. The data in that exhibit, which were derived from Pepco's monthly BSA filings, also depict dramatic reductions the reported Actual Monthly Revenue for the GT-3A class and in revenue per customer. The reported customer count for the GT-3A class fell to 31.5% of the number shown for the prior month (Dec 2015), but Actual Revenue dropped to just 25.2% of the level of revenue for the class in the prior month.[14] Similar, although less dramatic declines in customer counts and Actual Monthly Revenue are observable in the

[13] AOBA's understanding is that some customers went multiple months without receiving a bill when the Company's new billing system was activated.

[14] It appears that the GT-3A class was particularly affected by the referenced shift in the reporting of data for the final billing cycle to following month. However, it is unclear how much of the observed decline in actual revenue for the class is attributable to that shift in reporting and how much is attributable to other factors. Although the numbers of customers and revenue affected by the shift in the Company's reporting of data for its final January 2015 billing cycle to the next month, Pepco has never offered any assessment of the numbers of customers and actual revenues affected by that shift.

pages of Exhibit AOBA (A)-6 for the Residential Rate R, GSD, and GT-LV classes.

The one notable exception, however, is found in the reported Actual Monthly Revenue for the GSD class. Although the reported Customer Count for the GSD class declined by 10% from the prior month the reported Actual Revenue for that class increased 42% from the prior month and 79% from the actual revenue level reported for January 2014. Moreover, actual revenue per customer soared. As a result of the decline in reported customers and the sharp increase in reported actual revenue, revenue per customer for the GSD class for January 2015 was 58% above the level of December 2015 and nearly 102% above the actual revenue per customer for the GSD class in January 2014. This rather dramatic and unexplained increase in reported Actual Monthly Revenue for the GSD class in January 2015 in the context of a decline in the class' reported number of customers is a matter of particular concern. In my assessment it suggests that revenue from other classes may have been misapplied to the GSD class. If in fact that occurred it could have a significant impact on deferred revenue accounting within the BSA for all affected classes that may have impacted BSA rate determinations for multiple subsequent months.

Q. HOW SHOULD THE COMMISSION ADDRESS THIS CONCERN?

A. Given that Pepco has not been forthcoming with its own assessment of these matters, the Commission should require a detailed audit of Pepco's assignment of revenue by rate class since the startup of its new SolutionOne billing system with particular focus on the accounting of revenues for the Company's General Service and General Service Time Metered rate classifications. Further action should be dependent upon the outcome of that audit.

5. Separate BSA Treatment for MMAs

Q. HOW WOULD THE BSA MECHANISM NEED TO BE ADJUSTED IF THE MMA CUSTOMER COUNT CHANGES FROM NUMBER OF DWELLING UNITS TO THE NUMBER OF BUILDINGS?

A. As discussed in greater detail in the MMA rate design section of the direct testimony of AOBA witness Timothy Oliver, Pepco proposes to change the MMA customer count for rate design and billing purposes from numbers of dwelling units to numbers of accounts. This change is not reasonable or equitable and fails in both concept and execution. However, any effort to establish MMA customers as a separate class (or classes) of service,[15] will require adjustment to the Company's BSA mechanism. However, if despite the substantial inconsistencies and inequities in the data and methods underlying Pepco's proposed MMA rate designs, those rates are approved, considerable complexity will be added to the Company's current monthly BSA rate adjustment process. The tiered customer charge structure that Pepco proposes with the vastly different

[15] The establishment of separate rate classes for MMA-R and MMA-AE customers is reasonable and appropriate.

customer charges applied to each tier does not mesh well with the current use of uniform revenue per customer adjustments for all changes in numbers of customers within a class. Rather, it would appear that the Company would need to track changes in numbers of MMA customers by customer charge tier since the revenue impacts of the addition or loss of a customer would differ substantially depending on the tier to which a customer is assigned. No other class has such large differences in the levels of customer charges than can be billed to customers within the class. Further, while usage per dwelling unit for MMA's may fall within reasonably limited and predictable ranges, the usage of MMA accounts will differ greatly with the number of dwelling units served through an account.

AOBA also recognizes that regardless of the rate design adopted for a separate MMA class (or separate classes for current MMA-R and MMA-AE customers), noticeable adjustments to the BSA process will be required. For example, the Commission will need to determine whether adjustments to authorized monthly revenue for MMA customers will be determined on the basis of numbers of accounts served or numbers of dwelling units. In addition, the Commission will need to determine the portion of the current deferred revenue balance for the Rate R and Rate AE classes that should be attributed to MMA customers. Arguably MMA customers have contributed to current over-collection balances within the Company's most recent BSA filings, and should share in the benefits of those balances. Further, if the Company's tiered approach to the establishment of monthly customer charges for MMA accounts is accepted (a position AOBA does not support), the Commission will need to address the manner in which monthly BSA revenue targets for MMA customers will be determined.

Q. HOW SHOULD PEPCO'S DETERMINATION OF BSA RATE ADUSTMENTS BE MODIFIED TO REFLECT THE ESTABLISHMENT OF SEPARATE RATE CLASSES FOR MMA-R AND MMA-AE CUSTOMERS?

A. The Commission is strongly encouraged to adopt AOBA's approach to the design of MMA rates, and in the context of AOBA's MMA rate design proposal, the Company's current practice of developing authorized monthly revenues on a dollars-per-customer basis can be readily applied to MMA customers on a dollars per dwelling unit basis. Moreover, the over- or under-recovery balances for Rate R and Rate AE can be easily apportioned to the MMA class on the basis of numbers of customer equivalents where (as has been done for a number of years) each dwelling unit is treated as the equivalent of an individually metered residential customer.

<u>6. BSA Continuation</u>

Q. SHOULD PEPCO'S BSA FOR ITS DISTRICT OF COLUMBIA SERVICE BE CONTINUED?

A. Considering the problems discussed herein and the general lack of evidence that Pepco's BSA provides benefits to its District of Columbia customers, I do not find a compelling case for continuation of the Company's BSA mechanism.

When the BSA was first adopted, one of the key benefits that Pepco attributed to that mechanism was a reduction in the frequency of rate cases. That benefit has not materialized. Although there was a period of nearly 40 months between Pepco's filing of its applications in this case and in Formal Case No. 1103, the period between those filings was extended voluntarily by the Company to avoid filing a rate case during the pendency of its Merger proceeding.[16] It now appears that the Company will be making almost annual rate filings, and in the context of such frequent filings of base rate proceedings, the continuation of monthly rate adjustments between rate cases is difficult to justify.

Q. DOES PEPCO HAVE INCENTIVE TO REFINE ITS BSA PROCESS TO ADDRESS RATEPAYER CONCERNS REGARDING THE ACCURACY AND EQUITY OF MONTHLY BSA RATE ADJUSTMENTS?

A. No. To the extent that issues associated with the Company's focus on questions impacting the accuracy and equity of rate adjustments for individual rate classes and/or customers within rate classes, Pepco has little incentive to ensure their resolution. This is evidenced by the Company's failure to take timely action to replace its use of Active Billed Customer data with Count of Contracts data.

[16] Apparently, it was important to the Joint Applicants that their Merger proceeding not be considered a rate case.

Although it is obvious that Count of Contracts measures of numbers of customers are more stable and more consistent with the concepts underlying Pepco's monthly adjustment of "Allowed Revenue" by class, Pepco has not seized the initiative to make that change. As stated previously, it appears that Pepco views its BSA as primarily a Revenue Assurance Mechanism ("RAM"). As long as that mechanism provides assurance of the revenue the Company can record on its books, its concerns are satisfied.

To date most of the burden of assuring the reasonableness of the Company's BSA rate adjustment has fallen on the Commission Staff. Although those efforts are appreciated by District ratepayers, any continuation of Pepco's BSA mechanism should require that Pepco assume greater responsibility for the reasonableness and accuracy of monthly rate adjustment calculations. In this vein the Commission should require Pepco at its expense to re-compute its Allowed Revenues and its Deferred Revenue balances by rate class for each month since the cut-over to its new billing system in January 2015 using Count of Contracts data in place of Active Billed Customer data. I have reviewed all of the Company's District of Columbia BSA filings to date for this proceeding, and I do not believe that a requirement for Pepco to perform the re-calculation suggested above would be an unduly burdensome task. However, it might help to re-establish a measure of confidence in the Company's BSA rate adjustment process, if the Commission elects to continue that mechanism.

C. REVENUE REQUIREMENTS

Q. WHAT REVENUE REQUIREMENT ISSUES DO YOU ADDRESS IN THIS SECTION OF YOUR DISCUSSION OF ISSUES?

A. This section of my testimony addresses a limited number of additional revenue requirements related issues. As AOBA's resources are limited, it has not undertaken a detailed review of all elements Pepco's rate base, expenses, revenues, and ratemaking adjustments in this proceeding. Thus, AOBA will rely on the evidentiary record developed through hearings, as well as the testimony of witnesses for the Office of People's Counsel and other parties to develop revenue requirements issues not addressed in this testimony. In addition, to the revenue impacts that result from the cost of capital recommendations, presented above, this section of my testimony will address:

- Pepco's failure to properly reflect Normal Weather billing determinants in its assessment of expected revenue at present rates when computing its need for additional revenue in this proceeding;

- Pepco's ratemaking adjustment for Costs to Achieve its merger with Exelon;

- Pepco's request for recovery of inappropriate amounts of rate case expense for this proceeding;

- Pepco's failure to identify, explain and justify significant increases in elements of its test year expenses;

- Pepco's inclusion of non-recurring billing system transition costs as part of its claimed on-going expenses for ratemaking purposes;

- Pepco's unjustified request for ratemaking adjustments related to deferred and on-going credit-related disconnect and reconnect costs.

AOBA also observes large percentage increases in a number of the Company's operating expense accounts since its last base rate case that have not been explicitly identified, explained or justified as part of the Company's direct and supplemental direct testimony in this proceeding. The increases to which I refer are increases in excess of 20% (although several far exceed that level) that cannot be accepted as simply a reflection of the influences of cost inflation over time. The burden of justifying those significant cost increases must be placed squarely on the Company. Thus, any such increases that the Company has not justified as part of its direct case, must be denied.

<u>1. Reflection of Normal Weather Revenue at Present Rates</u>

> ***Issue No. 2:***
>
> *Are Pepco's proposed operating revenues, test year sales, and number of customers, as adjusted, just and reasonable?*
>
> *b. Is Pepco's weather normalization study reasonable and in compliance with the previous Commission directives?*

Q. HAVE YOU REVIEWED THE TEST YEAR SALES, NUMBERS OF CUSTOMERS, AND REVENUE ON WHICH PEPCO PREMISES ITS REVENUE INCREASE REQUEST IN THIS PROCEEDING?

A. I have. My review included examination of both the Company's actual test year data as well as its development of estimates of weather normalized billing determinants and weather normalized revenue.

Q. ARE THE NUMBERS OF TEST YEAR CUSTOMERS BY RATE CLASS THAT PEPCO USES REASONABLE?

A. In general, I believe they are. It appears that the test year numbers of customers Pepco has employed reflect data from its "Count of Contracts" report, and I find those measures of numbers of customers to be appropriate for use in representing the Company's actual numbers of customers for the test year. The key concern I have is that the numbers of Master Metered Apartment ("MMA") customers should be represented in numbers of dwelling units served not in terms of numbers of accounts. This matter is also addressed in the testimony of AOBA Timothy Oliver.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE TEST YEAR MEASURES OF KWH ON WHICH PEPCO RELIES?

A. Yes. I find large and inexplicable variations in Pepco's actual and estimates of weather corrected (i.e., weather normalized) kWh by month. It appears that Pepco made no effort to ensure that it's reported actual kWh data by rate class reflect measures of actual kWh use in each month and are not distorted by either: (1) large billing adjustments which may impact reported kWh for a given month based on substantial upward or downward adjustments of billed usage in prior months; and/or (2) data processing errors or reporting errors. Although kWh measures for larger classes may be sufficient to mask the influence of such problems, the impacts of billing adjustments can become quite apparent for smaller classes. Moreover, my experience suggests that where large fluctuations appear in the reported usage for small classes the potential increases that less readily discernible distortions in reported data for larger classes may also exist. Examples of the types of problematic data found in both the Company's actual and Weather Corrected kWh data are presented in Exhibit AOBA (A)-7.

Exhibit AOBA (A)-7 highlights observations for two classes. Those are the MMA-AE class and the GT-3B class. For the MMA-AE (a customer group for which AOBA has particular sensitivity), the Company's reported actual and weather corrected kWh suggest that the customers in that class had **negative usage** in three months of the test year (i.e., the months of April, June, and September of 2015). It also shows unexpectedly large fluctuations in kWh use for other months. Similar observations are made for the GT-3B class. Pepco's purported actual test year data for the GT-3B show 91% of total annual kWh use for that rate class in two months: May 2015 and October 2015. The Company's also data also reflect substantial **negative kWh** usage class for two months, and zero kWh use in two other months. Moreover, the Company's estimates of weather corrected kWh for the GT-3B class suggest that when normalized for the effects of weather months with **zero** reported actual kWh would have negative kWh consumption.

Q. WHY SHOULD THE COMMISSION EXPRESS CONCERN REGARDING THE COMPANY'S TEST YEAR DATA FOR THESE COMPARATIVELY SMALL CLASSES OF SERVICE?

A. First, these observations raise concerns regarding the reliability of the data and methods Pepco has generally applied to produce its estimates of weather corrected test year billing determinants. Second, incorrect monthly distributions of actual test year kWh use cause the Company's applications of degree day based adjustments to that usage to be distorted. Third, Pepco's weather corrected kWh influence the Company's assessment of usage by rate block and/or usage for summer and winter seasonal periods, and those estimates directly affect the Company's computations of revenue at both present and proposed rates. Fourth, distortions in Pepco's representations of kWh use by month impact its development of proposed BSA revenue targets by rate class by month that it proposes to use in the computation of monthly BSA rate adjustments. Fifth, distorted representations of actual and weather corrected kWh by month can be expected to influence the reasonableness and appropriateness of the projections of kWh by rate class that Pepco uses as the denominators for its calculation of its BSA cents per kWh rate adjustments.

Q. DOES PEPCO'S COMPUTATION OF ITS REQUIRED REVENUE INCREASE IN THIS PROCEEDING REFLECT THE INFLUENCE OF NORMAL WEATHER ON EXPECTED REVENUES AT PRESENT RATES?

A. No. The only elements of Pepco's filings in this case in which the Company incorporates consideration of the effects of normal weather on revenues are witness Janocha's revenue increase distribution and rate design analyses found in Exhibits Pepco (G)-1 and Pepco (2G)-1, and in those exhibits the Company's Normal Weather billing determinants are only used to compute revenue at **proposed** rates.

Q. SHOULD THE COMMISSION ACCEPT PEPCO'S DECISION NOT TO COMPUTE REVENUES AT PRESENT RATES USING ITS NORMAL WEATHER BILLING DETERMINANTS?

A. No. If the use of estimates of Normal Weather billing determinants is deemed necessary to appropriately assess the revenues Pepco can expect to collect in the rate effective period at its proposed rates, then the same billing determinants must be judged appropriate for use by the Company when assessing the revenue it can expect during the rate effective period at present rates. Pepco has not performed such an analysis.

Q. ARE THERE OTHER PROBLEMS IN PEPCO'S COMPUTATION OF ITS TEST YEAR REVENUES AT PRESENT RATES?

A. Yes. The Company has computed kWh by rate block that is inconsistent with the manner in which it is billed under its current tariff. For Pepco's R, AE, MMA-R, and MMA-AE classes, the Company has inappropriately assumed that adjustments to billed kWh would impact usage in the First 400 kWh rate block and its rate block for Over 400 kWh per month proportionally. That assumption is incorrect. Weather normalization adjustments should be applied to the last kWh billed to each customer each month. Thus, when kWh by rate block are properly adjusted, most of the adjustment should be applied to tail block (over 400 kWh block) usage. Although there are some customers whose usage does not exceed 400 kWh in a given month, those customers are less likely to have substantial weather sensitive electricity use, and therefore, there is no need for application of weather related adjustments to their usage. For this reason, I have re-computed the Company's rate block distribution of its Weather Normalization adjustments for the Company's R, AE, MMA-R, and MMA-AE customer classes in a manner that assigns all of the estimated kWh adjustment to the Company's Over 400 kWh rate block.

Q. WHAT IS THE SIGNIFICANCE OF YOUR RE-CALCULATION OF THE RATE BLOCK DISTRIBUTION OF PEPCO'S NORMAL WEATHER KWH ADJUST-MENTS?

A. Since usage in the Over 400 kWh rate block is billed at higher charges than usage in the First 400 kWh block, this change amplifies the magnitude of the Company's computed Normal Weather Adjustments to revenue for classes having blocked kWh charges (i.e., Rate R, AE, MMA-R, and MMA-AE).

Q. HAVE YOU IDENTIFIED ANY OTHER FACTORS THAT IMPACT THE COMPANY'S REVENUES AT PRESENT RATES?

A. Yes. The Company has also incorrectly calculated its revenue at present rate for MMA-R and MMA-AE customers. Exhibit Pepco (2G)-1, page 5 of 19, indicates that 657,840 MMA-R customers are used in the Company's computation of customer charge revenue for that class at present rates. For the MMA-AE class, 8,304 customer billing units are used. Yet, the Company's exhibit suggests that for the summer and winter months combined MMA-R customers used a total of 5,245,736 kWh in the First 400 kWh block and 312,068,278 kWh in the Over 400 kWh block. This is not possible. Dividing the First 400 kWh block usage by the number of MMA-R customers (dwelling units), we find that Pepco's reported first block usage only accounts for an average of about 8 kWh per dwelling unit per month. However the Over 400 block reflects an average of 474 kWh. This implies that each MMA-R dwelling unit used an average of 482 kWh per dwelling unit per month. Thus, on average 400 kWh per dwelling unit should have been billed at the First block rate and only 82 kWh per dwelling unit should be billed at the Over 400 block rate. Clearly, the Company's presentation has not properly reflected a multiple application of the Company's residential rate.

Q. DO YOU HAVE ANY OTHER CORRECTIONS TO PEPCO'S DETERMINATION OF REVENUES AT PRESENT RATES FOR MMA CUSTOMERS?

A. Yes. The number of MMA-R customers that Pepco uses to compute MMA-R customer charge revenue at present rates is understated. Where Exhibit (2G)-1 uses 657,840 MMA-R customer months billed, the Company's workpapers and BSA filings reflect 679,738 MMA-R customer months. Thus, it appears that the Company's number of MMA-R customer months for the test year is understated by 21,898. Based on a customer charge of $10.25 per month, an additional upward adjustment of **$224,454.50** to total MMA-R revenues at present rates should be made.

Q. DO YOU RECOMMEND THAT PEPCO'S ESTIMATES OF NORMAL WEATHER BILLING DETERMINANTS BE USED TO ASSESS REVENUE AT PRESENT RATES FOR THE PURPOSE OF DETERMINING PEPCO'S NEED FOR ADDITIONAL REVENUE IN THIS PROCEEDING?

A. No. I would support the use of appropriate estimates of Normal Weather billing determinants in Pepco's assessments of expected revenue at both present and proposed rates when computing its need of additional revenue. However, as explained herein, the Company's Normal Weather billing determinants have not been properly developed for classes having blocked kWh charges.

Q. WHEN CORRECTED NORMAL WEATHER BILLING DETERMINANTS ARE USED TO COMPUTE PEPCO'S REVENUE AT PRESENT RATES, WHAT IS THE EFFECT ON THE COMPANY'S REVENUE INCREASE REQUEST?

A. Exhibit AOBA (A)-8 indicates that kWh by rate block are properly computed, revenue at present rates would yield a **$3,613,916** reduction to total revenue at present rates. That is a **$2,559,813** greater reduction than Pepco's normal weather billing determinants by rate block in Exhibit Pepco (2G)-1 produce.

<u>2. Recovery of Merger Costs to Achieve</u> **(Adjustment 19)**

Issue Nos. 10a and 10b

a. Is Pepco's proposed treatment of the costs to achieve and merger synergy savings just and reasonable and consistent with Merger Commitment 27?

b. Is Pepco's request to establish regulatory assets for costs to achieve appropriate and reasonable?

Q. WHAT RATE TREATMENT DOES PEPCO REQUEST FOR ITS MERGER-RELATED COSTS TO ACHIEVE?

A. Pepco Witnesses McGowan and Ziminsky both address the Company's plan for recovery of Merger-related Costs to Achieve ("CTA"). Pepco's ratemaking adjustment for Merger-related cost is found in Adjustment 29 at page 34 of 45 in Exhibit Pepco (E)-1. Adjustment 29 seeks to establish a regulatory asset for a test year average balance of $8,391,000 dollars, which after adjustment for accumulated deferred taxes would yield a $4,467,000 addition to rate base. The Company asks that it be permitted to amortize its CTA regulatory asset over five years for an annual amortization expense of $1,678,000. According to Pepco Witness McGowan, the Company is also "*proposing an adjustment to reflect the first year synergy savings*."[17]

Q. IS PEPCO'S PROPOSAL FOR THE ESTABLISHMENT OF A REGULATORY ASSET FOR MERGER-RELATED CTA AND AMORTIZATION OF THAT

[17] Exhibit Pepco (B), page 4, lines 20-21.

ASSET OVER FIVE YEARS A REASONABLE AND APPROPRIATE REQUEST IN THIS PROCEEDING?

A. No. I cannot reconcile the Company's proposal in this case with the testimony of Witness Khouzami for the Joint Applicants the was filed in support of the Non-Unanimous Settlement in that case.[18] Witness Khouzami stated at page 7, lines 14-17, of that testimony that the Company commits "*not to recover an annual CTA amount that exceeds an annual synergies amount **in any test period***." (Emphasis Added). Yet, Witness McGowan's testimony in this proceeding explicitly recognizes, "there are no merger synergies reflected in the unadjusted test period…"[19] In an effort to accelerate the Company's recovery of Merger-related CTA, Witness McGowan indicates that Pepco is proposing an adjustment to reflect "*projected net synergy savings, that based on the current forecast, are expected to be allocated to Pepco-DC in the first year*."[20]

Q. IN THE CONTEXT OF THE FOREGOING, SHOULD THIS COMMISSION PERMIT PEPCO'S RECOVERY OF CTA THROUGH A REGULATORY ASSET AMORTIZATION?

A. No. Pepco's proposal is inconsistent with the substance and spirit of the Joint Applicant's representations in Formal Case No. 1119. The suggestion that "projected net synergy savings" be viewed as an acceptable substitute for actual realized synergy savings during the test period should be rejected, and the

18 Formal Case No. 1119, Joint Applicant's Exhibit (5A).
19 Exhibit Pepco (B), page 4, lines 22-23.
20 Exhibit Pepco (B), page 5, lines 3-4.

Company should be denied recovery of CTA until it can demonstrate actual test year synergy savings in excess of the amount of CTA for which it seeks regulatory asset treatment. Furthermore, no CTA costs should be added to rate base or in any way added to the Company's test year costs of service until actual synergy savings of equal or greater value are demonstrated.

3. Recovery of Rate Case Expenses ***(Pepco Adjustment 10)***

Q. WHAT IS THE NATURE OF PEPCO'S ADJUSTMENT 10?

A. Pepco's Adjustment 10 identifies over $3.6 million of current rate case costs that the Company seeks to place in a regulatory asset to be amortized over 3 years, with the unamortized balance net of those costs, net of deferred taxes, included in the Company's rate base.

Q. IS THE COMPANY'S PROPOSAL REASONABLE?

A. Only in part. Although Pepco's proposal appears to generally follow past precedents, it offers no incentive for the Company to limit the amount of rate case expense incurred.

A frequently expressed concern from many parties is the expense of litigating rate cases. However, in the context of the increases Pepco has requested in his proceeding as well as prior proceedings, the level of rate case expense is easily justified by achieved reductions in the Company's initial rate increase requests. In base rate proceedings before this Commission over the last decade, Pepco's approved revenue increases have on average equaled only about **49%** percentage of the amount initially requested. (See Exhibit AOBA (A)-9). Given the size of the Company's initial rate increase request in this proceeding, the Company's $3.6 million current rate case expense claim in this proceeding equates to only about 8% of the rate reduction in revenue requirements that ratepayers can expect to achieve through litigation of the case. Stated in other terms, the expected ratepayer benefit cost ratio is nearly 12:1.

Thus in an effort to control rate case litigation expenses, I recommend that the Company's allowed recovery of rate case expenses should be tied to the proportion of the Company's initial request that ultimately receives Commission approval. With the proviso that no disallowance would apply to approved amounts that are within 10% of the Company's initial request.

4. Non-Recurring Billing System Transition Costs

Q. DO PEPCO'S CLAIMED TEST YEAR EXPENSES IN THIS PROCEEDING INCLUDE SIGNIFICANT NON-RECURRING TRANSITION COSTS ASSOCIATED WITH THE IMPLEMENTATION OF ITS NEW BILLING SYSTEM?

A. Yes. Although Pepco has offered no identification of such non-recurring costs in its direct testimony in this case, such costs were identified by the Maryland Commission Staff and other parties in Pepco's recently completed base rate case in Maryland (MDPSC Case No. 9418). On a system basis Pepco has incurred $11.57 million of non-recurring transition costs directly associated with the implementation of its new billing system, as well as $1.151 million of non-recurring transition costs associated with its legacy billing system. Of those amounts, $4,473,000 of non-recurring new billing system transition costs associated with its new billing system and $438,000 of non-recurring legacy system non-recurring transition costs are attributable to its District of Columbia jurisdictional service.

Q. HOW SHOULD SUCH NON-RECURRING TRANSITION COSTS BE TREATED FOR RATEMAKING PURPOSES?

A. Those costs significantly overstate the billing system operating expenses Pepco expects to experience during the rate effective period and should be removed from the Company's claimed operating expenses in this proceeding. Furthermore, in Maryland the Commission Staff recommended and Pepco, as well as other parties (including AOBA) and the Commission, ultimately agreed that the Company should recover those transition costs through a five-year amortization. A similar treatment of the DC portion of those transition costs is appropriate in this proceeding.

5*. Remote Disconnect Costs (Adjustment 29)*

Q. HOW MUCH DOES PEPCO SEEK TO RECOVER FOR AMI-RELATED DEFERRED DISCONNECT COSTS?

A. The Company's request for recovery of Deferred Remote Disconnect/Reconnect Costs is set forth in the direct testimony of Pepco Witness Ziminsky at page 23. Table 1 on that page identifies $2,827,598 of Deferred Disconnect/Reconnect Costs that Pepco seeks to include in a regulatory asset that would be amortized over five years. Of the claimed $2.8 million, Witness Ziminisky states the $1.736 million reflects amounts deferred through the end of the test year (i.e., through March 31, 2016. An additional $1.091 million represents further deferrals that Pepco anticipates between the end of the test year and the start of the rate effective period. The Company also presents a proposed adjustment to increase its test year expenses by $873,000 to reflect an ongoing annual level of expense for "credit-related manual disconnect and reconnect of customers". Witness Ziminski cites the testimony of Pepco Witness Lefkowitz and asserts that her Direct Testimony indicates that in Formal Case No. 1103, "*the Commission approved the Company's treatment of costs associated with credit-related manual disconnect and reconnect of customers*." However, that is exactly what either Witness Lefkowitz states in her direct testimony in this proceeding or what the Commission stated in Order No. 17424 in Formal Case No. 1103.

The direct testimony of Pepco witness Lefkowitz also addresses cost claims. Witness Lefkowitz explains that the cost of labor required to perform disconnections and reconnections and (unspecified) savings related to the remoted connect and disconnect functionality of its AMI system were removed from the Company's test year costs in Formal Case No. 1103 as part of the Company's Adjustment 7 that was accepted by the Commission in Order No. 17424. However, under 15 DCMR § 312 the Company is still required to physically visit a premise and knock on the door prior to disconnecting a customer for credit purposes. Due to this requirement, Witness Lefkowitz claims that Pepco has not been able to achieve the full benefit anticipated from its AMI remote disconnect/reconnect functionality.

Q. DO YOU QUESTION PEPCO'S CLAIM FOR RECOVERY OF DEFERRED REMOTE DISCONNECT/RECONNECT COSTS?

A. I do. Pepco's response to AOBA Data Request 6-20, indicates that the requirements of 15 DCMR § 312 predated the Company's deployment of AMI. As a utility frequently engaged in credit-related disconnect/reconnect activities, Pepco was aware, or should have been aware, of the constraints imposed by 15 DCMR § 312 at the time it proposed Adjustment 7 in Formal Case No. 1103. Thus, at best, it appears that Pepco knowingly claimed AMI savings in Formal Case No. 1103 that it could not achieve and misrepresented the value of functionality within its AMI system.

Furthermore, my review of the Company's testimony and exhibits in Formal Case No. 1103, as well as the Commission's discussion of Adjustment 7 in Order No. 17424,[21] finds that neither Pepco's presentation of its Adjustment 7 nor the Commission's discussion of that Adjustment in Order No. 17424 included any specific reference to disconnect/reconnect costs or related savings. In fact, Witness Hook's testimony in support of Adjustment 7 in Formal Case No. 1103 comprised a single sentence which offers only a generalized reference to "on-going AMI-related savings, net of on-going incremental costs."[22]

Q. DOES 15 DCMR § 312 RESTRICT THE COMPANYS USE OF AMI FOR RECONNECT ACTIVITIES?

A. No. The requirement under 15 DCMR § 312 for an in-person visit to the customer's premises only applies to credit-related disconnects.

Q. IN RESPONSE TO DISCOVERY REQUESTS HAS PEPCO PROVIDED ANY COST DATA IN SUPPORT OF ITS CLAIMED COST DEFERRALS AND ITS ADDITION TO TEST YEAR EXPENSES FOR ON-GOING CREDIT RELATED DISCONNECT/RE-CONNECT ACTIVITIES?

A. Yes. Pepco's responses to AOBA Data Requests 6-20 and 6-21 offer information relating to the Company's cost claims.

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21 Order No. 17424, pages 200-201.
22 Formal Case No. 1103, Exhibit Pepco (C), page 12, lines 8-10.

Q. DOES THE DATA PROVIDED IN RESPONSE TO AOBA'S DATA REQUESTS SUPPORT THE COMPANY'S CLAIMED COSTS?

A. No, they do not. The attachment to AOBA Data Request 6-20 provides historical disconnect and reconnect cost data for the years 2010 through 2015 and the first three months of 2016. However, the DC disconnect and reconnect costs shown reflect an "Assumed Percentage to DC" without any explanation or documentation of the basis for the percentage assumed. For the years 2013 through the end of the test year, the Company provides what is labeled as Field Collection Costs for Pepco DC with separate entries for "Disconnects/Door Knock" and "Reconnects." However, the data for the twelve months of the test year (i.e., the twelve months ended March 2016) only reflect Disconnect/Reconnect costs totaling $125,424. That reflects an average monthly expense of only a little over $10,000. Yet, Pepco's response to AOBA Data Request 6-21, claims that the Company's on-going level of expense of $873,000 per year is based on its claimed average monthly cost of $72,762.38 for the first four months of 2016 multiplied by 12 to arrive at Pepco's claimed on-going level of annual expense. However, the Company's claimed average cost for the first four months of 2016 is at best curious for two reasons. First, the Company offers no support for its claimed costs for the **first four months** of 2016. As previously noted, its response to AOBA Data Request 6-20 only provides data for the **first three months** of 2016 and the average for those three months is only about $60,000 per month. Second, Pepco offers no rationale for its use of data for only four months of 2016 when its response to AOBA Data Request 6-20 provides substantial historical data. I can only surmise that reliance on a broader set of historical data would almost necessarily require use of some or all of the 2015 data, and that information does not support the Company's cost claim.

Q. DO YOU HAVE ANY FURTHER OBSERVATIONS REGARDING PEPCO'S ADJUSTMENT 29 AND ITS REQUEST FOR BOTH RECOVERY OF COST DEFERRALS AND ON-GOING COSTS FOR CREDIT-RELATED DISCON-NECTS AND RECONNECTS?

A. Yes. The Company's claimed $1.736 million for amounts deferred through the end of the test year and the additional $1.091 million of deferrals for its projects for the period between the end of the test year and the start of the rate effective period, both appear to represent extrapolations from the $873,000 on-going expense that Pepco claims to have developed based on data for the first four months of 2016. The $1.736 million figure equates to two full years at $873,000 per year (or 24 months at $72,762 per month). Similarly, the $1.091 million of projected deferrals equates to 1.25 years at $873,000 per year or 15 months at $72,762 per month. In other words, the historic period cost deferral for which the Company seeks recovery are not based on actual prior period costs or estimates of savings developed for presentation in Formal Case No. 1103 when Pepco claims to have received approval for its treatment of credit-related disconnect/ reconnect costs and savings.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION REGARDING THE DISCONNECT/RECONNECT COST CLAIMS INCLUDED IN THE COMPANY'S ADJUSTMENT 29 IN THIS PROCEEDING?

A. I find that the Company has failed to provide compelling and substantial support for these cost claims and the Commission should reject both the Company's request for amortization of deferred costs and its claimed on-going level of disconnect/reconnect expense.

D. RATE IMPACT CONSIDERATIONS

Q. WHICH COMMISSION DESIGNATED ISSUES DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. As discussed in the Summary at the beginning of this testimony, the distribution of rate impacts in this proceeding must be addressed in the context of a broader set of considerations than in most base rate proceedings. For this reason, my discussion herein will necessarily involve matters relating to Issue Nos. 13, 13a, 10d, and 10e.

Q. WHAT ARE ISSUE NOS. 13, 13A, 10D, AND 10E AS SET FORTH IN ORDER NO. 18550?

A. Attachment A to Order No. 18550 specifies those issues in the following terms:

Issue No. 13:

Is Pepco's proposed allocation of its revenue requirement just and reasonable?

Issue No. 13a:

Is Pepco's proposed plan for eliminating negative class rates of return reasonable?*?*

Issue No. 10d:

Is Pepco's proposed allocation of Customer Base Rate Credits and the new Rider CBRC just and reasonable*?*

Issue No. 10e:

Is Pepco's proposal for an Incremental Offset just and reasonable*?*

Q. WHAT IS YOUR OVERALL ASSESSMENT OF PEPCO'S PROPOSALS FOR DISTRIBUTION OF RATE IMPACTS AMONG CLASSES IN THIS PROCEEDING?

A. The Company has been provided a unique opportunity to make progress on a difficult issue in this proceeding (i.e., obtaining real progress toward having significant portions of its customer base make positive contributions to the Company's return requirements). However, the Company has, once again, dropped the ball. Although aspects of the Company's proposal may have superficial appeal, key elements of the proposals that Pepco presents have little or no likelihood of success.

The unique opportunity in this case is provided by the availability of $25.6 million of Base Rate Credits and $1 million per year of Incremental Offsets. But Pepco squanders those credits by attempting to fully insulate residential customers from any immediate effects of the largest overall revenue increase the Company has ever requested. This is pure folly. The benefits of Base Rate Credits are only temporary, and the rate increases they disguise will continue on long after rate credits are fully expired. Moreover, given Pepco's capital spending plans, the Company's own presentations suggest that additional rate increase requests can be expected within a short period following this rate case. Thus, within a few months of the Company's expected exhaustion of Base Rate Credits (and Incremental Offsets) effective rate increases that Residential customers will experience when those credits go away will be compounded by another rate increase and further progress toward elimination of negative rates of return will be stymied, not facilitated. In addition, Pepco's assessment of the expected duration Base Rate Credits fails to include a provision for growth in the number of residential customers.

Pepco's myopic plan for the elimination of negative rates of return ignores basic fundamental cost of service facts. Most importantly, the Company's plan inappropriately assumes that there will be no slippage in Rate R and Rate AE class rates of return between rate cases. Yet, despite the Commission's efforts to improve the relative rates of return for those rate classes in Formal Case No. 1103, Order No. 17424, Pepco's computed rates of return in this case are more negative than they were going into Formal Case No. 1103. Pepco ignores the impacts of the Company's DCPLUG program on future residential class rates of return. As this Commission is aware, the legislated design of DCPLUG charges requires that those charges for Residential customers be set at levels that will necessarily fail to recover the costs that will be allocated to the Company's residential classes in future base rate proceedings. Thus, the DCPLUG rate design virtually ensures that, all other things being equal, the UPC revenues received from Pepco's residential classes will under-collect appropriately allocated costs for those classes in the Company's next base rate case.

In this context, it should be obvious that more substantial efforts to improve revenue recovery from Rate R and AE customers are needed. Yet, Pepco's proposals represent little more than a "business as usual" approach. Ignoring the growth in the Company's negative Rate R and AE rates of return between cases, as well as the Commission's precedent of placing a substantially greater than average increase on Rate R and AE customers in Formal Case No. 1103, Pepco proposes in this case to apply an overall rate increase for its Rate R and AE customers that in combination is less than the overall average increase it requests. Where the Commission found it appropriate to place 47% of the Company's approved increase in Formal Case No. 1103 on the Company's residential classes, Pepco's proposals in this case assign only 21.1% of the overall increase to its Residential classes. It appears the Company has greater interest in extending the period of no effective rate increases for Residential customers than it has interest in achieve real progress toward narrowing the current differences in class rate of return in the District and/or eliminating negative rates of return.

1. Pepco's Proposed Revenue Increase Distribution

Q. HOW DOES PEPCO PROPOSE TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE IN THIS PROCEEDING?

A. The Company's proposal was initially presented in Exhibit Pepco (G), the direct testimony of Pepco Witness Janocha, and Exhibit Pepco (G)-1 accompanying that testimony. The Company's subsequently provided a revised revenue increase distribution in Exhibit Pepco (2G)-1 that was submitted with Witness Janocha's supplemental direct testimony. As detailed by Witness Janocha on page 1 of Exhibit (2G)-1, the Company's revised revenue increase request represents an overall 22.72% increase. With certain limited exceptions, the Company's proposed distribution of that increase does not deviate significantly from an across-the-board revenue increase distribution.

Q. IS PEPCO'S PROPOSED DISTRIBUTION OF ITS REQUESTED REVENUE INCREASE AMONG RATE CLASSES REASONABLE?

A. Although I am supportive of efforts to narrow differences in class rates of return as well as efforts to specifically address classes with extremely high ROR's at present rates, the limited increases witness Janocha places on the Residential Rate R and Rate AE classes are inappropriate and inconsistent with this Commission's policies and precedents. Despite the substantially negative rates of return at present rates for the residential classes, Pepco's proposals result in a combined average increase for Rate R and Rate AE customers that is actually slightly less than the system average increase. As a result, the percentage of the total increase allocated to Pepco's overall residential classes in this proceeding is only 19.6% where this Commission applied 47% of the overall increase to Residential customers in Formal Case No. 1103.[23] It is also notable that the Company takes a very different approach when determining the proposed increase for the other class with a substantially negative rate of return, Street Light – Energy service. For that class Pepco proposes an increase of 2.3 times the system average with no offer of offsetting base rate credits.

2. Pepco's Plan for Eliminating Negative Rates of Return

Q. WHAT IS PEPCO'S PLAN FOR ELIMINATING NEGATIVE RATES OF RETURN?

A. The Company's plan for eliminating negative rates of return is discussed in the direct testimony of Pepco witnesses McGowan. In that plan, Pepco proposes to reach 0.0% rates of return for its Residential Rate R and Rate AE classes over

[23] Formal Case No. 1103, Order No. 17424, paragraph 437, page 173. It should also be noted that the data presented in Exhibit Pepco (2G)-1, page 1, indicate that the same residential classes account for 22.3% of Pepco's total base rate distribution revenue at present rates.

three rate cases. In approximate terms the Company's proposal is to move from a **-4.5%** current ROR for the combination of the R and AE classes to a **-3.0%** ROR for those classes at the end of this case. In subsequent cases Pepco targets similar 1.5% per case ROR improvements in the Rate R and Rate AE RORs with the hope of achieving a -1.5% ROR combined ROR at the end of the second case and a 0.0% ROR by the end of the third case.

Q. DOES PEPCO'S FILED PLAN FOR ELIMINATING NEGATIVE RATES OF RETURN REPRESENT REASONABLE AND APPROPRIATE EFFORTS TO MEET ITS COMMITMENT TO ELIMINATE NEGATIVE RATES OF RETURN AND NARROW DIFFERENCES IN CLASS RATES OF RETURN?

A. No. It is a plan that lacks sound conceptual and analytical foundations. It is also a plan that realistically has no greater likelihood of achieving real improvements over time than the plans for gradual adjustment to class rate of return that Pepco has offered in past proceedings. In addition, it is a plan that appears to view a zero rate of return of its residential Rate R and Rate AE classes as the ultimate objective, rather than a plan that sees the elimination of negative rates of return as an important step in the process toward more equitable rates, but not an end-point. The Company's plan also lacks consideration of other known factors that can be expected to impact progress toward eliminating negative rates of return in future cases, such as the influences of the DCPLUG program and historical slippage in residential rates of return between rate cases.

The case-to-case slippage in residential rates of return (i.e., a problem not generally experienced for other classes) suggests that there may be fundamental problems in the Company's pricing of service to residential customers that contribute to the erosion of residential rates of return between rate cases. One observable difference between the Company's treatment of residential and commercial customers that may contribute to this problem, may be found in the differences between the Company's service connection and line extension policies for residential and commercial customers. The Company's present policies often require commercial customers to absorb a greater portion of the up-front costs of facilities (either through contributions in aid of construction (CIAC) and/or the customers installation of facilities) than it requires from residential customers.

In addition, the Company's plan offers no consideration of other possible measures to foster improvements in residential rates of return between rate cases. I have previously encouraged the Commission to consider measures such as inflation-based adjustments to residential rates between rate cases. The Company's "plan," however, elects to address this problem only in more narrow terms that lack dynamic consideration of the problem and factors contributing to the difficulties in achieving real progress in efforts to improve residential rates of return over time. This is not unexpected for a firm that is virtually assured its collection of an approved level of revenues and, as a result, is less sensitive to questions regarding the customer classes from which it must collect those revenues.

As I have previously stated, the Company's plan is destined for failure. Moreover, if Residential Rate R and Rate AE RORs are found in the next case to have slipped backward, the Company will face an even greater problem. Without the availability of Base Rate Credits, the larger adjustments to residential rates that will be needed to achieve the next step in its three-step plan will be even more difficult for those customers to absorb. Thus, the Commission could be faced with the difficult question of placing much larger rate impacts on residential customers or abandoning the Company's plan as presented in this case.

<u>3. Application of Base Rate Credits and Incremental Offsets</u>

Q. HOW DOES PEPCO PROPOSE TO USE THE BASE RATE CREDITS AND INCREMENTAL OFFSETS THAT ARE PROVIDED BY THE MERGER AGREEMENT?

A. Pepco's proposal is to use all of the available Base Rate Credits and Incremental Offsets to protect Residential and MMA customers from the entirety of the Company's requested base rate increase until the early part of 2019. Witness McGowan explains that the Company expects that those Base Rate Credits and Incremental Offsets will not be exhausted until February of 2019 for Residential customers and until March 2019 for MMA customers. Despite this Commission's assessment that all customers should participate in the benefits provided by available Customer Investment Funds, Pepco proposes no direct benefits for customers in any of its non-residential rate classes the District.

Q. DO YOU SUPPORT THE COMPANY'S PROPOSED USE OF BASE RATE CREDITS AND INCREMENTAL OFFSETS?

A. No. Pepco's proposal for use of available Base Rate Credits and Incremental Offset is poorly conceived, counterproductive and inconsistent with the expressed desires of the Commission. Pepco apparently has no concerns regarding denial of any opportunity for commercial customers to participate in direct merger-related benefits even though it is the Company's commercial customers who bear the entirety of Pepco's return requirements. The Company mantra must be something like "Let's bite the hand that feed us."

Additionally, there is no compelling reason to use the proposed Incremental Offsets. Those funds are simply an unwise form of deficit financing that should be avoided. If Incremental Offsets are used, they will only be used for the benefit of residential customers, and thus, the Company's Residential classes should bear full responsibility for the returns that must be paid for the use of those funds. Yet, it must be questioned how residential classes that currently provide no contributions to the Company's return requirements on its rate base investment, will pay the costs of required returns on Incremental Offset funds without further eroding the overall earned rates of return for those classes. Thus, the Commission is strongly urged to deny any and all elements of the Company's proposals that are dependent upon the use of Incremental Offsets.

***4.* AOBA's Rate Plan and Revenue Increase Distribution**

Q. HOW SHOULD THE COMMISSION EQUITABLY DISTRIBUTE PEPCO'S REVENUE INCREASE REQUEST WHILE MAXIMIZING THE BENEFITS OF ADDITIONAL FUNDS MADE AVAILABLE THROUGH THE MERGER?

A. AOBA recognizes that the extent of current negative rates of returns for the Residential R and AE classes have grown to the point that elimination of those negative RORs represents a substantial challenge. Moreover, AOBA is more than willing for the Commission to deploy the available Base Rate Credits in a manner that at least cushions some of the impact of measures necessary to achieve real progress toward eliminating negative rates of return. However, the representations of Pepco witness McGowan that "*the commercial customer class will see its share of the revenue requirement decrease as the negative RORs on Residential and Residential-AE class are eliminated over the next three base rate cases*," is little more that meaningless posturing. In the context of Pepco's proposals in this case, the combined Rate R and Rate AE classes would receive slightly less than that the average increase, as well as a much smaller share of Pepco's overall revenue increase than the Commission assigned to those classes in Formal Case No. 1103. Witness McGowan's suggestion of benefits for commercial customers is little more than a distant mirage in what is little more than a regulatory “desert.”

With this backdrop, I present an illustrative revenue increase distribution in Exhibit AOBA (A)-9 which attempts to make greater progress toward narrowing class rates of return while using Base Rate Credits to offset a portion, but not all, of the increase assigned to classes with negative rates of return. Following the example, presented by the Joint Applicant’s Witness Khouzami in his October 30 2015 testimony Formal Case No. 1119, Exhibit AOBA (A)-9 assumes that Pepco is ultimately granted approval of half (i.e, 50%) of its initial $85.48 million revenue increase request in this proceeding. That would produce an overall percentage increase for the Company of 11.8%. From that overall (or average increase) increases are distributed among rate classes to foster the narrowing of class rates of return.

First, the two classes with the most extreme RORs at present rates (i.e., the TN and GS-HV classes) are provided reductions in their revenue requirements that are intended to lower their post-increase rates of return to not more than 2.5 times the system average. While the resulting reductions in the RORs for those classes are substantial, the dollars required to achieve those results are not. For those two classes the combined revenue reduction is less than $63,000.

Second, to facilitate greater movement in the RORs, the revenue requirements for all classes having negative rates of return are increased by 2.5

times the overall average increase percentage. This would raise their revenue requirements by 29.6%. However, provision is made for all portions of their increases in excess of the overall average to be offset through the application of Base Rate Credits for an estimated period of 21 months or approximately through the end of March 2019. With Base Rate Credits netted out, the effective rate increase for those rate classes (Rates R, AE and SL) would be only 11.8%. The remaining revenue requirements are distributed uniformly to all other classes resulting in a 7.85% revenue increase for those classes.

Q. WHAT PERCENTAE OF THE OVERALL REVENUE INCREASE DOES THIS PROPOSAL PLACE ON RESIDENTIAL CUSTOMERS?

A. The entire residential class, including residential R, AE, RTM and MMA customer would receive 47.8% of the overall increase. This is only slightly more than the Commission assigned to those classes in Formal Case No. 1103.

Q. ARE THE BASE RATE CREDITS THAT YOU PROPOSE FOR CUSTOMERS IN CLASSES RECEIVING GREATER THAN AVERAGE REVENUE INCREASE PERCENTAGES USE ALL OF THE AVAILABLE BASE RATE CREDITS?

A. No. I estimate that over the period through the end of March 2019 only about $22.55 million of credits would be required for those classes.

Q. HOW SHOULD THE BALANCE OF THE AVAILABLE BASE RATE CREDITS BE USED?

A. Those funds should be used for two purposes.

First, a portion of the remaining funds (e.g., $500,000 to $750,000 per year) should be earmarked to provide improved customer service to non-residential customers. Pepco has agreed to a similar use of a portion of incremental merger Customer Investment Funds in Maryland, and a similar program would provide DC's non-residential customers a similar benefit. Non-residential customers and their representatives spend considerable time and resources trying to deal with a call center and customer service system that are not particularly well-designed to meet their needs and answer their questions. Additional assistance in this area would be greatly appreciated, and funding of the proposal would still require only a small percentage of the overall direct merger benefits.

Second, I recommend that the balance of these funds be held in reserve to address potential growth in the Company's residential class such that there will be greater assurance the credits for residential customers will not be forced to terminate earlier than proposed herein. Again, I see this as a more financially sound alternative to a plan that relies on funding credits through Incremental Offsets without any allowance for growth in the number of customers receiving credits.

E. REFLECTION OF MERGER COMMITMENTS ***(Issue Nos. 10, 10a, and 10b)***

Issue No. 10

Are all Formal Case No. 1119 Merger Commitments properly reflected in the Application?

Q. ARE COMMITMENTS TO MAKE FUTURE CHARITABLE CONTRIBUTIONS ON PEPCO'S BOOKS?

A. No, they are not. The Merger Settlement Agreement accepted by this Commission clearly indicate that the pledge of over $18 million in future charitable contributions for the District of Columbia represent a commitment by Exelon and its affiliates, not a commitment made by Pepco. In that context, it is inappropriate for that commitment to be reflected on Pepco's books.

F. ALTERNATIVE RATEMAKING STRUCTURES

Q. ARE THERE ANY CAUTIONS THE COMMISSION SHOULD CONSIDER IN ITS ASSESSMENT OF ALTERNATIVE RATEMAKING STRUCTURES?

A. Yes. The Commission needs to ensure than any ratemaking alternatives it may adopt are compatible with its existing polices and priorities. For example, the Commission should be hesitant to advance incentives that might encourage a re-bundling of utility services or further narrow the portion of the Company's customer base that presently carries the burden of Pepco's entire required return on investment. We have entered into an era in which the costs of alternative sources of energy supply are becoming increasingly competitive with utility provided services, and in that context, the Commission must guard against actions that might drive away the very customers on whom the system relies for maintenance of its financial health.

In an evolving industry alternative ratemaking structures should not be viewed as long-term solutions. Rather, the Commission may view alternative ratemaking structures as tools for facilitating the achievement of specific, reasonably near-term, goals. However, it must also recognize that once such goals are achieved, revision or termination of alternative ratemaking structures may be necessary. Goals that are too easily achieved by utilities generally cannot be relied upon to generate substantial ratepayer benefits. Further, alternative ratemaking structures should not be viewed as a replacement for rigorous regulatory oversight. Effective regulation requires a knowledgeable and involved Commission that continues to serve a leadership role.

Q. IS THE COMPANY'S REQUEST FOR THIS COMMISSION TO INVESTIGATE THE USE OF A FULLY FORECASTED TEST YEAR REASONABLE?

A. Not at this time. The record in this case raises numerous questions regarding the data and methods the Company has employed to forecast kWh use by its customers and to compute weather normalization adjustments. Until those issues are fully resolved and the Company provides the Commission with substantial evidence of its ability to reasonably forecast future costs and revenues, consideration of the use of a fully forecasted test year is not warranted.

Q. SHOULD THIS COMMISSON UNDERTAKE A FURTHER INVESTIGATION OF PERFORMANCE BASED RATEMAKING METHODS?

A. Again, not at this time. Until more substantial determinations are made regarding the future structure of Pepco's distribution utility operations in the District, it is difficult to identify many specific behaviors and/or performance measures for which incentives would be appropriate. However, one area in which a performance based ratemaking measure can be productive at this time is the implementation of the incentive structure I have outlined in this testimony for encouraging reductions in rate case expenses. The incentive can be approved now for application to the Company's next base rate filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. It does.

Potomac Electric Power Company

DCPSC Formal Case No 1139

Cost of Equity - Proxy Group Analysis

Ln No	Analytic Model	Average Dividend Yield	Dividend Growth Component	Adjusted Dividend Yield	Earnings Growth Rate	Indicated Rate of Return
	DCF Cost of Equity					
1	Zacks	3.52%	0.19%	3.72%	5.49%	9.20%
2	CNN	3.52%	0.19%	3.71%	5.37%	9.08%
3	Yahoo	3.52%	0.19%	3.71%	5.33%	9.04%
4	**Average of DCF Results**					**9.11%**

Ln No		Current Risk-Free Rate	Projected Long Term Risk-Free Rate	Average
	CAPM Analysis			
	Value Line Betas			
5	@ 7.00% MRP	8.28%	9.78%	9.03%
6	@ 8.00% MRP	9.02%	10.52%	9.77%
7	**Average of CAPM Results**			**9.40%**
8	**Average of DCF and CAPM Results**			**9.25%**
9	**Recommendation**			**9.25%**

Potomac Electric Power Company

DCPSC Formal Case No 1139

Dividend Yields & Earnings Growth Data for Hevert Proxy Group Companies

Ln No	Company		Market Price Per Share 1/ High	Market Price Per Share 1/ Low	Market Price Per Share 1/ Average	Indicated Dividend Per Share 1/	Dividend Yield	Projected 5-Year Earnings Growth Zacks 2/	Projected 5-Year Earnings Growth CNN 3/	Projected 5-Year Earnings Growth Yahoo 4/	Computed DCF Returns Zacks 2/	Computed DCF Returns CNN 3/	Computed DCF Returns Yahoo 4/
1	ALLETE, Inc.	ALE	$ 65.41	$ 47.93	$ 56.67	$ 2.08	3.67%	5.50%	6.00%	5.00%	9.37%	9.89%	8.85%
2	Alliant Energy Corporation	LNT	40.99	$ 29.07	$ 35.03	$ 1.18	3.37%	6.10%	7.15%	6.60%	9.67%	10.76%	10.19%
3	Ameren Corporation	AEE	54.08	$ 41.33	$ 47.71	$ 1.76	3.69%	6.10%	6.95%	5.60%	10.01%	10.90%	9.50%
4	American Electric Power Co.	AEP	$ 71.32	$ 54.08	$ 62.70	$ 2.36	3.76%	5.40%	2.00%	1.89%	9.37%	5.84%	5.73%
5	Avista Corporation	AVA	$ 45.22	$ 33.00	$ 39.11	$ 1.37	3.50%	5.30%	5.30%	5.65%	8.99%	8.99%	9.35%
6	CenterPoint Energy, Inc.	CNP	$ 24.71	$ 16.05	$ 20.38	$ 1.03	5.05%	5.50%	4.63%	5.73%	10.83%	9.92%	11.07%
7	CMS Energy Corporation	CMS	$ 46.25	$ 34.18	$ 40.22	$ 1.24	3.08%	6.60%	6.55%	7.27%	9.89%	9.84%	10.58%
8	Consolidated Edison, Inc.	ED	$ 81.88	$ 60.30	$ 71.09	$ 2.68	3.77%	2.80%	2.48%	2.12%	6.68%	6.34%	5.97%
9	DTE Energy Company	DTE	$ 100.45	$ 77.35	$ 88.90	$ 3.30	3.71%	5.80%	5.35%	5.63%	9.73%	9.26%	9.55%
10	Eversource Energy	ES	$ 60.44	$ 48.18	$ 54.31	$ 1.78	3.28%	6.10%	6.00%	5.82%	9.58%	9.47%	9.29%
11	Great Plains Energy Inc.	GXP	$ 32.74	$ 25.57	$ 29.16	$ 1.10	3.77%	6.60%	6.00%	8.00%	10.62%	10.00%	12.07%
12	IDACORP, Inc.	IDA	$ 83.40	$ 65.03	$ 74.22	$ 2.20	2.96%	4.30%	4.35%	4.10%	7.39%	7.44%	7.19%
13	NorthWestern Corporation	NWE	$ 63.75	$ 51.95	$ 57.85	$ 2.00	3.46%	5.00%	5.00%	4.50%	8.63%	8.63%	8.11%
14	OGE Energy Corp.	OGE	$ 33.10	$ 23.37	$ 28.24	$ 1.21	4.29%	5.20%	6.00%	4.00%	9.71%	10.54%	8.46%
15	Otter Tail Corporation	OTTR	$ 37.75	$ 25.20	$ 31.48	$ 1.25	3.97%	NA	6.00%	6.00%	NA	10.21%	10.21%
16	Pinnacle West Capital Corp.	PNW	$ 82.78	$ 60.70	$ 71.74	$ 2.62	3.65%	4.50%	5.00%	4.45%	8.32%	8.83%	8.26%
17	PNM Resources, Inc.	PNM	$ 36.15	$ 27.90	$ 32.03	$ 0.88	2.75%	6.80%	7.11%	6.85%	9.73%	10.05%	9.79%
18	Portland General Electric Co.	POR	$ 45.21	$ 35.04	$ 40.13	$ 1.28	3.19%	6.20%	5.50%	6.20%	9.59%	8.87%	9.59%
19	SCANA Corporation	SCG	$ 76.41	$ 56.50	$ 66.46	$ 2.30	3.46%	5.50%	6.00%	6.33%	9.15%	9.67%	10.01%
20	Westar Energy, Inc.	WR	$ 57.49	$ 40.00	$ 48.75	$ 1.52	3.12%	5.00%	4.40%	4.45%	8.27%	7.66%	7.71%
21	Xcel Energy Inc.	XEL	$ 45.42	$ 34.33	$ 39.88	$ 1.36	3.41%	5.40%	4.90%	5.72%	8.99%	8.48%	9.33%
22	**Mean**		**$ 56.43**	**$ 42.24**	**$ 49.33**	**$ 1.74**	**3.52%**	5.49%	**5.37%**	**5.33%**	9.20%	9.08%	9.04%
23	Exelon Corp.	EXC	$ 37.70	$ 25.09	$ 31.40	$ 1.27	4.05%	4.30%	4.00%	2.64%	8.52%	8.21%	6.79%
24	FirstEnergy Corp.	FE	$ 36.60	$ 30.29	$ 33.45	$ 1.44	4.31%	-0.40%	-1.26%	-5.27%	3.89%	2.99%	-1.19%

Potomac Electric Power Company
DCPSC Formal Case No 1139

Capital Asset Pricing Model (CAPM) Cost of Equity Estimates
With Value Line Betas and Current Risk-Free Rate

Ln No	Company		Value Line Beta 1/	Risk Premium 7.00%	Risk-Free Rate 3.15%	Value Line Beta 1/	Risk Premium 8.00%	Risk-Free Rate 3.15%
1	ALLETE, Inc.	ALE	0.80	5.60%	8.75%	0.80	6.40%	9.55%
2	Alliant Energy Corporation	LNT	0.70	4.90%	8.05%	0.70	5.60%	8.75%
3	Ameren Corporation	AEE	0.70	4.90%	8.05%	0.70	5.60%	8.75%
4	American Electric Power Co.	AEP	0.70	4.90%	8.05%	0.70	5.60%	8.75%
5	Avista Corporation	AVA	0.70	4.90%	8.05%	0.70	5.60%	8.75%
6	CenterPoint Energy, Inc.	CNP	0.90	6.30%	9.45%	0.90	7.20%	10.35%
7	CMS Energy Corporation	CMS	0.70	4.90%	8.05%	0.70	5.60%	8.75%
8	Consolidated Edison, Inc.	ED	0.60	4.20%	7.35%	0.60	4.80%	7.95%
9	DTE Energy Company	DTE	0.70	4.90%	8.05%	0.70	5.60%	8.75%
10	Eversource Energy	ES	0.70	4.90%	8.05%	0.70	5.60%	8.75%
11	Great Plains Energy Inc.	GXP	0.70	4.90%	8.05%	0.70	5.60%	8.75%
12	IDACORP, Inc.	IDA	0.80	5.60%	8.75%	0.80	6.40%	9.55%
13	NorthWestern Corporation	NWE	0.70	4.90%	8.05%	0.70	5.60%	8.75%
14	OGE Energy Corp.	OGE	0.90	6.30%	9.45%	0.90	7.20%	10.35%
15	Otter Tail Corporation	OTTR	0.90	6.30%	9.45%	0.90	7.20%	10.35%
16	Pinnacle West Capital Corp.	PNW	0.70	4.90%	8.05%	0.70	5.60%	8.75%
17	PNM Resources, Inc.	PNM	0.80	5.60%	8.75%	0.80	6.40%	9.55%
18	Portland General Electric Co.	POR	0.70	4.90%	8.05%	0.70	5.60%	8.75%
19	SCANA Corporation	SCG	0.70	4.90%	8.05%	0.70	5.60%	8.75%
20	Westar Energy, Inc.	WR	0.70	4.90%	8.05%	0.70	5.60%	8.75%
21	Xcel Energy Inc.	XEL	0.60	4.20%	7.35%	0.60	4.80%	7.95%
22	Average		0.73	5.13%	8.28%	0.73	5.87%	9.02%

1/ www.valueline.com, 11/17/16

Potomac Electric Power Company
DCPSC Formal Case No 1139

Capital Asset Pricing Model (CAPM) Cost of Equity Estimates

With Value Line Betas and Projected Long-Term Risk-Free Rate

Ln No	Company		Value Line Beta 1/	Risk Premium 7.00%	Risk-Free Rate 4.65%	Value Line Beta 1/	Risk Premium 8.00%	Risk-Free Rate 4.65%
1	ALLETE, Inc.	ALE	0.80	5.60%	10.25%	0.80	6.40%	11.05%
2	Alliant Energy Corporation	LNT	0.70	4.90%	9.55%	0.70	5.60%	10.25%
3	Ameren Corporation	AEE	0.70	4.90%	9.55%	0.70	5.60%	10.25%
4	American Electric Power Co.	AEP	0.70	4.90%	9.55%	0.70	5.60%	10.25%
5	Avista Corporation	AVA	0.70	4.90%	9.55%	0.70	5.60%	10.25%
6	CenterPoint Energy, Inc.	CNP	0.90	6.30%	10.95%	0.90	7.20%	11.85%
7	CMS Energy Corporation	CMS	0.70	4.90%	9.55%	0.70	5.60%	10.25%
8	Consolidated Edison, Inc.	ED	0.60	4.20%	8.85%	0.60	4.80%	9.45%
9	DTE Energy Company	DTE	0.70	4.90%	9.55%	0.70	5.60%	10.25%
10	Eversource Energy	ES	0.70	4.90%	9.55%	0.70	5.60%	10.25%
11	Great Plains Energy Inc.	GXP	0.70	4.90%	9.55%	0.70	5.60%	10.25%
12	IDACORP, Inc.	IDA	0.80	5.60%	10.25%	0.80	6.40%	11.05%
13	NorthWestern Corporation	NWE	0.70	4.90%	9.55%	0.70	5.60%	10.25%
14	OGE Energy Corp.	OGE	0.90	6.30%	10.95%	0.90	7.20%	11.85%
15	Otter Tail Corporation	OTTR	0.90	6.30%	10.95%	0.90	7.20%	11.85%
16	Pinnacle West Capital Corp.	PNW	0.70	4.90%	9.55%	0.70	5.60%	10.25%
17	PNM Resources, Inc.	PNM	0.80	5.60%	10.25%	0.80	6.40%	11.05%
18	Portland General Electric Co.	POR	0.70	4.90%	9.55%	0.70	5.60%	10.25%
19	SCANA Corporation	SCG	0.70	4.90%	9.55%	0.70	5.60%	10.25%
20	Westar Energy, Inc.	WR	0.70	4.90%	9.55%	0.70	5.60%	10.25%
21	Xcel Energy Inc.	XEL	0.60	4.20%	8.85%	0.60	4.80%	9.45%
22	Average		0.73	5.13%	9.78%	0.73	5.87%	10.52%

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Potomac Electric Power Company
DCPSC Formal Case No. 1139

AOBA Recommended Overall Cost of Capital
Based on Pepco Capital Structure and AOBA Recommended Cost of Equity
Dollars in Thousands

Ln No		Capitalization	Ratio	Cost Rate	Return
1	Common Equity	$ 956,382	**50.45%**	9.25%	4.67%
2	Long-Term Debt	$ 865,888	49.55%	5.48%	2.72%
3	**Total**	$ 1,822,270	100.00%		**7.38%**

Potomac Electric Power Company
DCPSC Formal Case No. 1139

Change In Pepco Revenue Requirement Resulting from AOBA Recommended ROR
Dollars in Thousands

AOBA Recommended ROR		**7.38%**
Pepco Requested ROR		8.00%
AOBA Recommended Reduction in Pepco ROR		-0.62%
Maryland Rate Base	$	1,731,816
Change in Required Return	$	(10,676)
Tax Gross-Up Factor		59.150%
Change in Revenue Requirement	**$**	**(18,049)**

Potomac Electric Power Company

DC PSC Formal Case No. 1139

Comparative Fluctuations in BSA Numbers of Customers by Rate Class

Ln No	Rate Class/Year	Minimum	Maximum	Average	Min Less Average	Max Less Average	Range	Range % Average
1	**Residential**							
2	**Pre-SolutionOne**							
3	2014	233,075	236,651	234,252	(1,177)	2,399	3,576	1.53%
4	**Post-SolutionOne Implementation**							
5	2015	218,053	250,080	241,782	(23,729)	8,298	32,027	13.25%
6	2016	230,311	258,148	243,999	(13,688)	14,149	27,837	11.41%
7	**GSD**							
8	**Pre-SolutionOne**							
9	2014	5,177	5,385	5,282	(105)	103	208	3.94%
10	**Post-SolutionOne Implementation**							
11	2015	4,760	5,631	5,280	(520)	351	871	16.50%
12	2016	4,720	5,664	5,221	(501)	443	944	18.08%
13	**GT-LV**							
14	**Pre-SolutionOne**							
15	2014	2,910	2,992	2,944	(34)	48	82	2.79%
16	**Post-SolutionOne Implementation**							
17	2015	2,343	3,325	2,976	(633)	349	982	33.00%
18	2016	2,892	3,511	3,162	(270)	350	619	19.58%
19	**GT-3A**							
20	**Pre-SolutionOne**							
21	2014	143	148	147	(4)	1	5	3.40%
22	**Post-SolutionOne Implementation**							
23	2015	47	187	144	(97)	43	140	97.33%
24	2016	132	198	157	(25)	41	66	42.15%
25	**MMA (Dwelling Units)**							
26	**Pre-SolutionOne**							
27	2014	55,198	55,904	55,521	(323)	383	706	1.27%
28	**Post-SolutionOne Implementation**							
29	2015	52,086	56,705	56,278	(4,192)	428	4,619	8.21%
30	2016	54,328	59,529	56,100	(1,772)	3,429	5,201	9.27%

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Comparison of Pepco DC Forecasted Distribution kWh from Monthly BSA Filings for Calendar Years 2016 and 2015

Forecasted kWh from BSA Reports - Calendar Year 2016

	Jan 16	Feb 16	Mar 16	Apr 16	May 16	Jun 16	Jul 16	Aug 16	Sep 16	Oct 16	Nov 16	Dec 16	Total
R	162,977,358	149,578,676	155,429,623	128,760,361	94,276,505	125,825,690	192,002,531	158,674,565	155,022,669	128,001,328	106,883,540	142,008,171	1,699,441,017
AE	62,982,631	63,013,661	51,957,721	35,292,551	25,733,781	29,388,571	31,152,771	30,527,481	30,576,931	20,998,611	23,729,481	40,433,861	445,788,052
RTM	1,687,613	1,594,014	1,570,853	1,403,756	924,566	1,220,434	1,861,443	1,533,605	1,366,264	1,163,267	1,107,714	1,499,615	16,933,144
GS ND	26,046,890	22,360,195	22,682,649	21,807,070	25,359,870	23,315,611	27,727,131	30,732,428	26,514,861	25,751,703	23,379,491	24,716,718	300,394,617
GSD	55,218,399	49,653,355	48,068,552	44,636,738	45,342,462	55,301,210	60,871,641	64,709,954	58,687,943	54,241,311	45,211,991	47,797,962	629,741,518
GS HV	57,069	148,194	82,733	116,628	148,186	139,385	168,508	166,094	158,572	129,395	121,220	128,153	1,564,137
GTLV	404,239,870	377,209,053	380,993,618	363,372,757	371,390,014	386,781,028	446,440,209	460,610,799	425,060,143	401,877,131	350,948,180	371,021,218	4,739,944,020
GT3A	201,211,192	171,748,753	185,789,976	181,795,947	207,210,698	211,600,570	250,123,393	255,550,922	236,368,102	228,031,592	194,961,107	206,112,217	2,530,504,469
GT3B	11,557,350	25,827,355	20,197,989	18,117,238	19,516,197	19,669,886	19,425,142	19,825,334	20,075,503	23,025,398	23,673,840	25,027,903	245,939,135
Total	925,978,372	861,133,256	866,773,714	795,303,046	789,902,279	853,242,385	1,029,772,769	1,022,331,182	953,830,988	883,219,736	770,016,564	858,745,818	10,610,250,109

Forecasted kWh from BSA Reports - Calendar Year 2015

	Jan 15	Feb 15	Mar 15	Apr 15	May 15	Jun 15	Jul 15	Aug 15	Sep 15	Oct 15	Nov 15	Dec 15	Total
R	165,650,498	151,215,572	155,429,623	128,760,361	112,811,474	145,997,637	201,171,782	198,469,617	190,654,818	140,589,943	124,415,079	141,880,145	1,857,046,549
AE	59,993,820	59,940,810	51,957,721	35,292,551	23,860,911	31,473,711	39,057,931	39,369,311	38,661,361	29,058,991	31,672,621	48,273,931	488,613,670
RTM	1,811,059	1,625,216	1,570,853	1,403,756	1,208,314	1,474,514	1,875,911	1,993,945	1,849,196	1,537,931	1,344,178	1,383,972	19,078,845
GS ND	22,287,450	19,162,504	22,682,649	21,807,070	21,870,834	23,022,339	24,673,652	26,701,498	25,818,924	23,661,277	20,091,727	23,115,426	274,895,350
GSD	52,411,045	48,549,293	48,068,552	44,636,738	46,489,054	53,505,941	58,701,938	63,328,087	58,796,439	52,513,993	41,395,190	47,267,366	615,663,636
GS HV	**13,133**	74,470	82,733	116,628	147,281	136,278	178,443	161,837	156,235	118,717	108,478	144,634	1,438,867
GTLV	399,915,161	377,861,698	380,993,618	363,372,757	360,445,505	388,311,475	464,573,573	438,664,129	431,862,973	390,676,622	339,000,039	381,411,012	4,717,088,562
GT3A	204,808,224	195,863,218	185,789,976	181,795,947	198,390,324	214,867,851	233,690,702	261,264,494	250,787,621	223,172,443	196,703,137	198,451,636	2,545,585,573
GT3B	19,921,757	18,660,788	20,197,989	18,117,238	19,007,187	18,326,887	21,012,062	17,469,449	20,412,934	17,339,992	16,955,954	19,775,982	227,198,219
Total	926,812,147	872,953,569	866,773,714	795,303,046	784,230,884	877,116,633	1,044,935,994	1,047,422,367	1,019,000,501	878,669,909	771,686,403	861,704,104	10,746,609,271

Growth in BSA Forecasted kWh from Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	(2,673,140)	(1,636,896)	-	-	(18,534,969)	(20,171,947)	(9,169,251)	(39,795,052)	(35,632,149)	(12,588,615)	(17,531,539)	128,026	(157,605,532)
AE	2,988,811	3,072,851	-	-	1,872,870	(2,085,140)	(7,905,160)	(8,841,830)	(8,084,430)	(8,060,380)	(7,943,140)	(7,840,070)	(42,825,618)
RTM	(123,446)	(31,202)	-	-	(283,748)	(254,080)	(14,468)	(460,340)	(482,932)	(374,664)	(236,464)	115,643	(2,145,701)
GS ND	3,759,440	3,197,691	-	-	3,489,036	293,272	3,053,479	4,030,930	695,937	2,090,426	3,287,764	1,601,292	25,499,267
GSD	2,807,354	1,104,062	-	-	(1,146,592)	1,795,269	2,169,703	1,381,867	(108,496)	1,727,318	3,816,801	530,596	14,077,882
GS HV	43,936	73,724	-	-	905	3,107	(9,935)	4,257	2,337	10,678	12,742	(16,481)	125,270
GTLV	4,324,709	(652,645)	-	-	10,944,509	(1,530,447)	(18,133,364)	21,946,670	(6,802,830)	11,200,509	11,948,141	(10,389,794)	22,855,458
GT3A	(3,597,032)	(24,114,465)	-	-	8,820,374	(3,267,281)	16,432,691	(5,713,572)	(14,419,519)	4,859,149	(1,742,030)	7,660,581	(15,081,104)
GT3B	(8,364,407)	7,166,567	-	-	509,010	1,342,999	(1,586,920)	2,355,885	(337,431)	5,685,406	6,717,886	5,251,921	18,740,916
Total	(833,775)	(11,820,313)	-	-	5,671,395	(23,874,248)	(15,163,225)	(25,091,185)	(65,169,513)	4,549,827	(1,669,839)	(2,958,286)	(136,359,162)

% Growth Over BSA Forecasted kWh for Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	-1.6%	-1.1%	0.0%	0.0%	-16.4%	-13.8%	-4.6%	-20.1%	-18.7%	-9.0%	-14.1%	0.1%	-8.5%
AE	5.0%	5.1%	0.0%	0.0%	7.8%	-6.6%	-20.2%	-22.5%	-20.9%	-27.7%	-25.1%	-16.2%	-8.8%
RTM	-6.8%	-1.9%	0.0%	0.0%	-23.5%	-17.2%	-0.8%	-23.1%	-26.1%	-24.4%	-17.6%	8.4%	-11.2%
GS ND	16.9%	16.7%	0.0%	0.0%	16.0%	1.3%	12.4%	15.1%	2.7%	8.8%	16.4%	6.9%	9.3%
GSD	5.4%	2.3%	0.0%	0.0%	-2.5%	3.4%	3.7%	2.2%	-0.2%	3.3%	9.2%	1.1%	2.3%
GS HV	**334.5%**	**99.0%**	0.0%	0.0%	0.6%	2.3%	-5.6%	2.6%	1.5%	9.0%	11.7%	-11.4%	8.7%
GTLV	1.1%	-0.2%	0.0%	0.0%	3.0%	-0.4%	-3.9%	5.0%	-1.6%	2.9%	3.5%	-2.7%	0.5%
GT3A	-1.8%	-12.3%	0.0%	0.0%	4.4%	-1.5%	7.0%	-2.2%	-5.7%	2.2%	-0.9%	3.9%	-0.6%
GT3B	-42.0%	**38.4%**	0.0%	0.0%	2.7%	7.3%	-7.6%	13.5%	-1.7%	**32.8%**	**39.6%**	26.6%	8.2%
Total	-0.1%	-1.4%	0.0%	0.0%	0.7%	-2.7%	-1.5%	-2.4%	-6.4%	0.5%	-0.2%	-0.3%	-1.3%

Change > -10% and < -20%
Change > -20%

Change > 10% and < 20%
Change > 20%

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Comparison of Pepco DC Forecasted Distribution kWh from Monthly BSA Filings for Calendar Years 2015 and 2014

Forecasted kWh from BSA Reports - Calendar Year 2015

	Jan 15	Feb 15	Mar 15	Apr 15	May 15	Jun 15	Jul 15	Aug 15	Sep 15	Oct 15	Nov 15	Dec 15	Total
R	165,650,498	151,215,572	155,429,623	128,760,361	112,811,474	145,997,637	201,171,782	198,469,617	190,654,818	140,589,943	124,415,079	141,880,145	1,857,046,549
AE	59,993,820	59,940,810	51,957,721	35,292,551	23,860,911	31,473,711	39,057,931	39,369,311	38,661,361	29,058,991	31,672,621	48,273,931	488,613,670
RTM	1,811,059	1,625,216	1,570,853	1,403,756	1,208,314	1,474,514	1,875,911	1,993,945	1,849,196	1,537,931	1,344,178	1,383,972	19,078,845
GS ND	22,287,450	19,162,504	22,682,649	21,807,070	21,870,834	23,022,339	24,673,652	26,701,498	25,818,924	23,661,277	20,091,727	23,115,426	274,895,350
GSD	52,411,045	48,549,293	48,068,552	44,636,738	46,489,054	53,505,941	58,701,938	63,328,087	58,796,439	52,513,993	41,395,190	47,267,366	615,663,636
GS HV	**13,133**	74,470	82,733	116,628	147,281	136,278	178,443	161,837	156,235	118,717	108,478	144,634	1,438,867
GTLV	399,915,161	377,861,698	380,993,618	363,372,757	360,445,505	388,311,475	464,573,573	438,664,129	431,862,973	390,676,622	339,000,039	381,411,012	4,717,088,562
GT3A	204,808,224	195,863,218	185,789,976	181,795,947	198,390,324	214,867,851	233,690,702	261,264,494	250,787,621	223,172,443	196,703,137	198,451,636	2,545,585,573
GT3B	19,921,757	18,660,788	20,197,989	18,117,238	19,007,187	18,326,887	21,012,062	17,469,449	20,412,934	17,339,992	16,955,954	19,775,982	227,198,219
Total	926,812,147	872,953,569	866,773,714	795,303,046	784,230,884	877,116,633	1,044,935,994	1,047,422,367	1,019,000,501	878,669,909	771,686,403	861,704,104	10,746,609,271

Forecasted kWh from BSA Reports - Calendar Year 2014

	Jan 14	Feb 14	Mar 14	Apr 14	May 14	Jun 14	Jul 14	Aug 14	Sep 14	Oct 14	Nov 14	Dec 14	Total
R	157,578,985	145,557,834	137,595,329	125,121,547	118,026,386	151,321,546	207,957,716	226,736,655	199,400,590	146,724,348	124,824,735	146,493,349	1,887,339,020
AE	68,984,153	65,544,247	53,542,772	33,648,840	22,650,540	26,247,070	37,276,140	41,513,600	36,446,370	27,143,970	29,345,560	45,119,780	487,463,042
RTM	1,862,988	1,594,595	1,522,976	1,376,152	1,387,065	1,646,547	1,946,278	2,092,590	2,064,372	1,717,273	1,295,076	1,557,270	20,063,182
GS ND	23,590,988	21,965,685	20,331,262	17,757,026	17,477,175	18,944,224	23,470,311	25,628,583	22,536,560	19,877,716	18,125,643	22,061,054	251,766,227
GSD	58,754,212	55,047,531	51,672,405	44,667,969	47,361,385	54,317,362	61,655,163	61,925,571	58,302,228	51,347,745	43,074,535	48,285,069	636,411,175
GS HV	114,677	127,724	105,457	187,428	128,511	158,983	198,295	119,794	207,560	113,459	103,896	125,611	1,691,395
GTLV	427,973,214	399,895,827	404,057,650	359,612,369	370,674,234	402,589,502	450,967,842	440,815,555	437,828,566	390,010,156	346,986,417	386,055,996	4,817,467,328
GT3A	212,096,290	201,562,914	217,508,190	209,492,628	210,912,313	230,118,824	257,199,136	252,949,374	241,552,332	225,893,220	192,047,222	204,182,875	2,655,515,318
GT3B	19,779,035	18,666,560	18,951,606	18,686,929	17,793,023	17,766,658	17,003,010	18,589,579	17,968,494	17,778,414	16,448,376	18,573,601	218,005,285
Total	970,734,542	909,962,917	905,287,647	810,550,888	806,410,632	903,110,716	1,057,673,891	1,070,371,301	1,016,307,072	880,606,301	772,251,460	872,454,605	10,975,721,972

Growth in BSA Forecasted kWh from Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	8,071,513	5,657,738	17,834,294	3,638,814	(5,214,912)	(5,323,909)	(6,785,934)	(28,267,038)	(8,745,772)	(6,134,405)	(409,656)	(4,613,204)	(30,292,471)
AE	(8,990,333)	(5,603,437)	(1,585,051)	1,643,711	1,210,371	5,226,641	1,781,791	(2,144,289)	2,214,991	1,915,021	2,327,061	3,154,151	1,150,628
RTM	(51,929)	30,621	47,877	27,604	(178,751)	(172,033)	(70,367)	(98,645)	(215,176)	(179,342)	49,102	(173,298)	(984,337)
GS ND	(1,303,538)	(2,803,181)	2,351,387	4,050,044	4,393,659	4,078,115	1,203,341	1,072,915	3,282,364	3,783,561	1,966,084	1,054,372	23,129,123
GSD	(6,343,167)	(6,498,238)	(3,603,853)	(31,231)	(872,331)	(811,421)	(2,953,225)	1,402,516	494,211	1,166,248	(1,679,345)	(1,017,703)	(20,747,539)
GS HV	(101,544)	(53,254)	(22,724)	(70,800)	18,770	(22,705)	(19,852)	42,043	(51,325)	5,258	4,582	19,023	(252,528)
GTLV	(28,058,053)	(22,034,129)	(23,064,032)	3,760,388	(10,228,729)	(14,278,027)	13,605,731	(2,151,426)	(5,965,593)	666,466	(7,986,378)	(4,644,984)	(100,378,766)
GT3A	(7,288,066)	(5,699,696)	(31,718,214)	(27,696,681)	(12,521,989)	(15,250,973)	(23,508,434)	8,315,120	9,235,289	(2,720,777)	4,655,915	(5,731,239)	(109,929,745)
GT3B	142,722	(5,772)	1,246,383	(569,691)	1,214,164	560,229	4,009,052	(1,120,130)	2,444,440	(438,422)	507,578	1,202,381	9,192,934
Total	(43,922,395)	(37,009,348)	(38,513,933)	(15,247,842)	(22,179,748)	(25,994,083)	(12,737,897)	(22,948,934)	2,693,429	(1,936,392)	(565,057)	(10,750,501)	(229,112,701)

% Growth Over BSA Forecasted kWh for Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	5.1%	3.9%	13.0%	2.9%	-4.4%	-3.5%	-3.3%	-12.5%	-4.4%	-4.2%	-0.3%	-3.1%	-1.6%
AE	-13.0%	-8.5%	-3.0%	4.9%	5.3%	19.9%	4.8%	-5.2%	6.1%	7.1%	7.9%	7.0%	0.2%
RTM	-2.8%	1.9%	3.1%	2.0%	-12.9%	-10.4%	-3.6%	-4.7%	-10.4%	-10.4%	3.8%	-11.1%	-4.9%
GS ND	-5.5%	-12.8%	11.6%	22.8%	25.1%	21.5%	5.1%	4.2%	14.6%	19.0%	10.8%	4.8%	9.2%
GSD	-10.8%	-11.8%	-7.0%	-0.1%	-1.8%	-1.5%	-4.8%	2.3%	0.8%	2.3%	-3.9%	-2.1%	-3.3%
GS HV	-88.5%	-41.7%	-21.5%	-37.8%	14.6%	-14.3%	-10.0%	35.1%	-24.7%	4.6%	4.4%	15.1%	-14.9%
GTLV	-6.6%	-5.5%	-5.7%	1.0%	-2.8%	-3.5%	3.0%	-0.5%	-1.4%	0.2%	-2.3%	-1.2%	-2.1%
GT3A	-3.4%	-2.8%	-14.6%	-13.2%	-5.9%	-6.6%	-9.1%	3.3%	3.8%	-1.2%	2.4%	-2.8%	-4.1%
GT3B	0.7%	**0.0%**	6.6%	-3.0%	6.8%	3.2%	23.6%	-6.0%	13.6%	**-2.5%**	**3.1%**	6.5%	4.2%
Total	-4.5%	-4.1%	-4.3%	-1.9%	-2.8%	-2.9%	-1.2%	-2.1%	0.3%	-0.2%	-0.1%	-1.2%	-2.1%

Change > -10% and < -20%
Change > -20%

Change > 10% and < 20%
Change > 20%

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Comparison of Pepco DC Forecasted Distribution kWh from Monthly BSA Filings for Calendar Years 2014 and 2013

Forecasted kWh from BSA Reports - Calendar Year 2014

	Jan 14	Feb 14	Mar 14	Apr 14	May 14	Jun 14	Jul 14	Aug 14	Sep 14	Oct 14	Nov 14	Dec 14	Total
R	157,578,985	145,557,834	137,595,329	125,121,547	118,026,386	151,321,546	207,957,716	226,736,655	199,400,590	146,724,348	124,824,735	146,493,349	1,887,339,020
AE	68,984,153	65,544,247	53,542,772	33,648,840	22,650,540	26,247,070	37,276,140	41,513,600	36,446,370	27,143,970	29,345,560	45,119,780	487,463,042
RTM	1,862,988	1,594,595	1,522,976	1,376,152	1,387,065	1,646,547	1,946,278	2,092,590	2,064,372	1,717,273	1,295,076	1,557,270	20,063,182
GS ND	23,590,988	21,965,685	20,331,262	17,757,026	17,477,175	18,944,224	23,470,311	25,628,583	22,536,560	19,877,716	18,125,643	22,061,054	251,766,227
GSD	58,754,212	55,047,531	51,672,405	44,667,969	47,361,385	54,317,362	61,655,163	61,925,571	58,302,228	51,347,745	43,074,535	48,285,069	636,411,175
GS HV	114,677	127,724	105,457	187,428	128,511	158,983	198,295	119,794	207,560	113,459	103,896	125,611	1,691,395
GTLV	427,973,214	399,895,827	404,057,650	359,612,369	370,674,234	402,589,502	450,967,842	440,815,555	437,828,566	390,010,156	346,986,417	386,055,996	4,817,467,328
GT3A	212,096,290	201,562,914	217,508,190	209,492,628	210,912,313	230,118,824	257,199,136	252,949,374	241,552,332	225,893,220	192,047,222	204,182,875	2,655,515,318
GT3B	19,779,035	18,666,560	18,951,606	18,686,929	17,793,023	17,766,658	17,003,010	18,589,579	17,968,494	17,778,414	16,448,376	18,573,601	218,005,285
Total	970,734,542	909,962,917	905,287,647	810,550,888	806,410,632	903,110,716	1,057,673,891	1,070,371,301	1,016,307,072	880,606,301	772,251,460	872,454,605	10,975,721,972

Forecasted kWh from BSA Reports - Calendar Year 2013

	Jan 13	Feb 13	Mar 13	Apr 13	May 13	Jun 13	Jul 13	Aug 13	Sep 13	Oct 13	Nov 13	Dec 13	Total
R	151,730,706	140,605,577	132,829,494	119,756,688	114,060,596	142,142,816	201,535,734	216,020,693	189,627,216	141,495,335	124,985,035	145,085,850	1,819,875,740
AE	62,361,294	59,723,373	51,811,593	40,206,290	30,158,200	32,874,161	41,527,802	44,197,431	41,447,535	34,134,687	35,229,552	48,534,971	522,206,889
RTM	1,631,334	1,696,078	1,590,737	1,371,442	1,278,076	1,456,245	1,917,133	2,252,652	1,986,441	1,632,252	1,339,274	1,529,627	19,681,291
GS ND	25,485,285	24,564,527	22,260,974	20,292,317	16,815,562	19,001,958	22,863,685	22,838,383	21,835,069	19,377,564	17,731,315	21,321,608	254,388,247
GSD	61,710,253	53,811,197	56,595,242	49,430,525	49,744,036	56,836,825	65,344,646	64,331,924	61,713,406	57,997,829	49,535,886	51,928,753	678,980,522
GS HV	105,463	101,404	102,897	80,767	14,815	284,245	169,537	190,636	174,480	123,874	130,582	124,455	1,603,155
GTLV	441,623,905	430,593,453	406,263,574	375,609,731	380,794,705	421,377,560	454,354,525	463,186,258	457,028,547	427,708,975	376,846,824	407,616,607	5,043,004,664
GT3A	225,590,523	211,168,050	228,188,848	213,228,214	226,284,637	244,448,151	269,834,523	269,390,616	272,601,017	243,027,343	208,698,038	226,283,943	2,838,743,903
GT3B	21,500,729	20,119,988	20,219,375	17,962,418	18,272,492	16,857,136	17,624,210	18,335,936	18,804,606	17,294,764	19,053,917	19,525,296	225,570,867
Total	991,739,492	942,383,647	919,862,734	837,938,392	837,423,119	935,279,097	1,075,171,795	1,100,744,529	1,065,218,317	942,792,623	833,550,423	921,951,110	11,404,055,278

Growth in BSA Forecasted kWh from Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	5,848,279	4,952,257	4,765,835	5,364,859	3,965,790	9,178,730	6,421,982	10,715,962	9,773,374	5,229,013	(160,300)	1,407,499	67,463,280
AE	6,622,859	5,820,874	1,731,179	(6,557,450)	(7,507,660)	(6,627,091)	(4,251,662)	(2,683,831)	(5,001,165)	(6,990,717)	(5,883,992)	(3,415,191)	(34,743,847)
RTM	231,654	(101,483)	(67,761)	4,710	108,989	190,302	29,145	(160,062)	77,931	85,021	(44,198)	27,643	381,891
GS ND	(1,894,297)	(2,598,842)	(1,929,712)	(2,535,291)	661,613	(57,734)	606,626	2,790,200	701,491	500,152	394,328	739,446	(2,622,020)
GSD	(2,956,041)	1,236,334	(4,922,837)	(4,762,556)	(2,382,651)	(2,519,463)	(3,689,483)	(2,406,353)	(3,411,178)	(6,650,084)	(6,461,351)	(3,643,684)	(42,569,347)
GS HV	9,214	26,320	2,560	106,661	113,696	(125,262)	28,758	(70,842)	33,080	(10,415)	(26,686)	1,156	88,240
GTLV	(13,650,691)	(30,697,626)	(2,205,924)	(15,997,362)	(10,120,471)	(18,788,058)	(3,386,683)	(22,370,703)	(19,199,981)	(37,698,819)	(29,860,407)	(21,560,611)	(225,537,336)
GT3A	(13,494,233)	(9,605,136)	(10,680,658)	(3,735,586)	(15,372,324)	(14,329,327)	(12,635,387)	(16,441,242)	(31,048,685)	(17,134,123)	(16,650,816)	(22,101,068)	(183,228,585)
GT3B	(1,721,694)	(1,453,428)	(1,267,769)	724,511	(479,469)	909,522	(621,200)	253,643	(836,112)	483,650	(2,605,541)	(951,695)	(7,565,582)
Total	(21,004,950)	(32,420,730)	(14,575,087)	(27,387,504)	(31,012,487)	(32,168,381)	(17,497,904)	(30,373,228)	(48,911,245)	(62,186,322)	(61,298,963)	(49,496,505)	(428,333,306)

% Growth Over BSA Forecasted kWh for Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	3.9%	3.5%	3.6%	4.5%	3.5%	6.5%	3.2%	5.0%	5.2%	3.7%	-0.1%	1.0%	3.7%
AE	10.6%	9.7%	3.3%	-16.3%	-24.9%	-20.2%	-10.2%	-6.1%	-12.1%	-20.5%	-16.7%	-7.0%	-6.7%
RTM	14.2%	-6.0%	-4.3%	0.3%	8.5%	13.1%	1.5%	-7.1%	3.9%	5.2%	-3.3%	1.8%	1.9%
GS ND	-7.4%	-10.6%	-8.7%	-12.5%	3.9%	-0.3%	2.7%	12.2%	3.2%	2.6%	2.2%	3.5%	-1.0%
GSD	-4.8%	2.3%	-8.7%	-9.6%	-4.8%	-4.4%	-5.6%	-3.7%	-5.5%	-11.5%	-13.0%	-7.0%	-6.3%
GS HV	**8.7%**	**26.0%**	2.5%	132.1%	767.4%	-44.1%	17.0%	-37.2%	19.0%	-8.4%	-20.4%	0.9%	5.5%
GTLV	-3.1%	-7.1%	-0.5%	-4.3%	-2.7%	-4.5%	-0.7%	-4.8%	-4.2%	-8.8%	-7.9%	-5.3%	-4.5%
GT3A	-6.0%	-4.5%	-4.7%	-1.8%	-6.8%	-5.9%	-4.7%	-6.1%	-11.4%	-7.1%	-8.0%	-9.8%	-6.5%
GT3B	-8.0%	**-7.2%**	-6.3%	4.0%	-2.6%	5.4%	-3.5%	1.4%	-4.4%	**2.8%**	**-13.7%**	-4.9%	-3.4%
Total	-2.1%	-3.4%	-1.6%	-3.3%	-3.7%	-3.4%	-1.6%	-2.8%	-4.6%	-6.6%	-7.4%	-5.4%	-3.8%

Change > -10% and < -20%
Change > -20%

Change > 10% and < 20%
Change > 20%

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Comparison of Pepco DC Forecasted Distribution kWh from Monthly BSA Filings for Calendar Years 2013 and 2012

Forecasted kWh from BSA Reports - Calendar Year 2013

	Jan 13	Feb 13	Mar 13	Apr 13	May 13	Jun 13	Jul 13	Aug 13	Sep 13	Oct 13	Nov 13	Dec 13	Total
R	151,730,706	140,605,577	132,829,494	119,756,688	114,060,596	142,142,816	201,535,734	216,020,693	189,627,216	141,495,335	124,985,035	145,085,850	1,819,875,740
AE	62,361,294	59,723,373	51,811,593	40,206,290	30,158,200	32,874,161	41,527,802	44,197,431	41,447,535	34,134,687	35,229,552	48,534,971	522,206,889
RTM	1,631,334	1,696,078	1,590,737	1,371,442	1,278,076	1,456,245	1,917,133	2,252,652	1,986,441	1,632,252	1,339,274	1,529,627	19,681,291
GS ND	25,485,285	24,564,527	22,260,974	20,292,317	16,815,562	19,001,958	22,863,685	22,838,383	21,835,069	19,377,564	17,731,315	21,321,608	254,388,247
GSD	61,710,253	53,811,197	56,595,242	49,430,525	49,744,036	56,836,825	65,344,646	64,331,924	61,713,406	57,997,829	49,535,886	51,928,753	678,980,522
GS HV	105,463	101,404	102,897	80,767	14,815	284,245	169,537	190,636	174,480	123,874	130,582	124,455	1,603,155
GTLV	441,623,905	430,593,453	406,263,574	375,609,731	380,794,705	421,377,560	454,354,525	463,186,258	457,028,547	427,708,975	376,846,824	407,616,607	5,043,004,664
GT3A	225,590,523	211,168,050	228,188,848	213,228,214	226,284,637	244,448,151	269,834,523	269,390,616	272,601,017	243,027,343	208,698,038	226,283,943	2,838,743,903
GT3B	21,500,729	20,119,988	20,219,375	17,962,418	18,272,492	16,857,136	17,624,210	18,335,936	18,804,606	17,294,764	19,053,917	19,525,296	225,570,867
Total	991,739,492	942,383,647	919,862,734	837,938,392	837,423,119	935,279,097	1,075,171,795	1,100,744,529	1,065,218,317	942,792,623	833,550,423	921,951,110	11,404,055,278

Forecasted kWh from BSA Reports - Calendar Year 2012

	Jan 12	Feb 12	Mar 12	Apr 12	May 12	Jun 12	Jul 12	Aug 12	Sep 12	Oct 12	Nov 12	Dec 12	Total
R	154,372,436	138,979,858	136,242,190	116,666,804	116,294,088	135,885,839	199,575,389	213,041,206	184,530,581	133,675,618	122,826,232	148,259,850	1,800,350,091
AE	69,014,177	63,713,079	53,158,269	39,816,358	31,537,881	32,886,674	42,787,465	47,998,076	41,574,646	33,160,934	35,148,816	42,427,079	533,223,454
RTM	1,733,309	1,719,287	1,633,211	1,467,939	1,346,960	1,505,739	2,067,383	2,099,096	2,002,840	1,542,287	1,293,279	1,402,012	19,813,342
GS ND	48,027,423	43,306,508	46,182,297	20,230,399	17,787,961	20,003,270	23,844,401	24,212,205	23,077,922	19,520,969	18,145,045	19,069,928	323,408,328
GSD	119,533,195	108,406,584	117,400,883	49,276,021	52,593,084	59,844,667	68,126,180	68,163,658	65,088,000	58,425,410	50,619,934	53,200,188	870,677,804
GS HV	89,679	85,819	89,642	110,250	95,433	151,618	168,192	174,600	141,700	111,477	98,080	112,102	1,428,592
GTLV	375,528,992	364,412,884	353,930,468	367,900,258	383,684,996	417,762,841	459,827,347	469,451,695	435,900,135	414,381,437	371,366,207	384,457,734	4,798,604,994
GT3A	191,827,890	178,712,327	198,794,554	223,050,916	231,102,739	255,244,100	272,356,423	286,280,956	263,890,653	247,091,075	222,274,879	214,437,116	2,785,063,628
GT3B	18,282,858	17,027,622	-	17,950,817	18,662,263	19,598,739	18,520,344	18,453,026	19,561,964	18,852,926	18,027,857	19,513,031	204,451,447
Total	978,409,959	916,363,968	907,431,514	836,469,762	853,105,405	942,883,487	1,087,273,124	1,129,874,518	1,035,768,441	926,762,133	839,800,329	882,879,040	11,337,021,680

Growth in BSA Forecasted kWh from Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	(2,641,730)	1,625,719	(3,412,696)	3,089,884	(2,233,492)	6,256,977	1,960,345	2,979,487	5,096,635	7,819,717	2,158,803	(3,174,000)	19,525,649
AE	(6,652,883)	(3,989,706)	(1,346,676)	389,932	(1,379,681)	(12,513)	(1,259,663)	(3,800,645)	(127,111)	973,753	80,736	6,107,892	(11,016,565)
RTM	(101,975)	(23,209)	(42,474)	(96,497)	(68,884)	(49,494)	(150,250)	153,556	(16,399)	89,965	45,995	127,615	(132,051)
GS ND	(22,542,138)	(18,741,981)	(23,921,323)	61,918	(972,399)	(1,001,312)	(980,716)	(1,373,822)	(1,242,853)	(143,405)	(413,730)	2,251,680	(69,020,081)
GSD	(57,822,942)	(54,595,387)	(60,805,641)	154,504	(2,849,048)	(3,007,842)	(2,781,534)	(3,831,734)	(3,374,594)	(427,581)	(1,084,048)	(1,271,435)	(191,697,282)
GS HV	15,784	15,585	13,255	(29,483)	(80,618)	132,627	1,345	16,036	32,780	12,397	32,502	12,353	174,563
GTLV	66,094,913	66,180,569	52,333,106	7,709,473	(2,890,291)	3,614,719	(5,472,822)	(6,265,437)	21,128,412	13,327,538	5,480,617	23,158,873	244,399,670
GT3A	33,762,633	32,455,723	29,394,294	(9,822,702)	(4,818,102)	(10,795,949)	(2,521,900)	(16,890,340)	8,710,364	(4,063,732)	(13,576,841)	11,846,827	53,680,275
GT3B	3,217,871	3,092,366	20,219,375	11,601	(389,771)	(2,741,603)	(896,134)	(117,090)	(757,358)	(1,558,162)	1,026,060	12,265	21,119,420
Total	13,329,533	26,019,679	12,431,220	1,468,630	(15,682,286)	(7,604,390)	(12,101,329)	(29,129,989)	29,449,876	16,030,490	(6,249,906)	39,072,070	67,033,598

% Growth Over BSA Forecasted kWh for Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	-1.7%	1.2%	-2.5%	2.6%	-1.9%	4.6%	1.0%	1.4%	2.8%	5.8%	1.8%	-2.1%	1.1%
AE	-9.6%	-6.3%	-2.5%	1.0%	-4.4%	0.0%	-2.9%	-7.9%	-0.3%	2.9%	0.2%	14.4%	-2.1%
RTM	-5.9%	-1.3%	-2.6%	-6.6%	-5.1%	-3.3%	-7.3%	7.3%	-0.8%	5.8%	3.6%	9.1%	-0.7%
GS ND	-46.9%	-43.3%	-51.8%	0.3%	-5.5%	-5.0%	-4.1%	-5.7%	-5.4%	-0.7%	-2.3%	11.8%	-21.3%
GSD	-48.4%	-50.4%	-51.8%	0.3%	-5.4%	-5.0%	-4.1%	-5.6%	-5.2%	-0.7%	-2.1%	-2.4%	-22.0%
GS HV	**17.6%**	**18.2%**	14.8%	-26.7%	-84.5%	87.5%	0.8%	9.2%	23.1%	11.1%	33.1%	11.0%	12.2%
GTLV	17.6%	18.2%	14.8%	2.1%	-0.8%	0.9%	-1.2%	-1.3%	4.8%	3.2%	1.5%	6.0%	5.1%
GT3A	17.6%	18.2%	14.8%	-4.4%	-2.1%	-4.2%	-0.9%	-5.9%	3.3%	-1.6%	-6.1%	5.5%	1.9%
GT3B	17.6%	**18.2%**	na	0.1%	-2.1%	-14.0%	-4.8%	-0.6%	-3.9%	**-8.3%**	**5.7%**	0.1%	10.3%
Total	1.4%	2.8%	1.4%	0.2%	-1.8%	-0.8%	-1.1%	-2.6%	2.8%	1.7%	-0.7%	4.4%	0.6%

Change > -10% and < -20%
Change > -20%

Change > 10% and < 20%
Change > 20%

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Comparison of Pepco DC Forecasted Distribution kWh from Monthly BSA Filings for Calendar Years 2012 and 2011

Forecasted kWh from BSA Reports - Calendar Year 2012

	Jan 12	Feb 12	Mar 12	Apr 12	May 12	Jun 12	Jul 12	Aug 12	Sep 12	Oct 12	Nov 12	Dec 12	Total
R	154,372,436	138,979,858	136,242,190	116,666,804	116,294,088	135,885,839	199,575,389	213,041,206	184,530,581	133,675,618	122,826,232	148,259,850	1,800,350,091
AE	69,014,177	63,713,079	53,158,269	39,816,358	31,537,881	32,886,674	42,787,465	47,998,076	41,574,646	33,160,934	35,148,816	42,427,079	533,223,454
RTM	1,733,309	1,719,287	1,633,211	1,467,939	1,346,960	1,505,739	2,067,383	2,099,096	2,002,840	1,542,287	1,293,279	1,402,012	19,813,342
GS ND	48,027,423	43,306,508	46,182,297	20,230,399	17,787,961	20,003,270	23,844,401	24,212,205	23,077,922	19,520,969	18,145,045	19,069,928	323,408,328
GSD	119,533,195	108,406,584	117,400,883	49,276,021	52,593,084	59,844,667	68,126,180	68,163,658	65,088,000	58,425,410	50,619,934	53,200,188	870,677,804
GS HV	89,679	85,819	89,642	110,250	95,433	151,618	168,192	174,600	141,700	111,477	98,080	112,102	1,428,592
GTLV	375,528,992	364,412,884	353,930,468	367,900,258	383,684,996	417,762,841	459,827,347	469,451,695	435,900,135	414,381,437	371,366,207	384,457,734	4,798,604,994
GT3A	191,827,890	178,712,327	198,794,554	223,050,916	231,102,739	255,244,100	272,356,423	286,280,956	263,890,653	247,091,075	222,274,879	214,437,116	2,785,063,628
GT3B	18,282,858	17,027,622	-	17,950,817	18,662,263	19,598,739	18,520,344	18,453,026	19,561,964	18,852,926	18,027,857	19,513,031	204,451,447
Total	978,409,959	916,363,968	907,431,514	836,469,762	853,105,405	942,883,487	1,087,273,124	1,129,874,518	1,035,768,441	926,762,133	839,800,329	882,879,040	11,337,021,680

Forecasted kWh from BSA Reports - Calendar Year 2011

	Jan 11	Feb 11	Mar 11	Apr 11	May 11	Jun 11	Jul 11	Aug 11	Sep 11	Oct 11	Nov 11	Dec 11	Total
R	148,685,381	137,674,581	128,183,673	121,324,663	110,452,581	144,212,892	207,200,352	208,618,118	185,012,103	139,045,597	117,517,473	138,154,847	1,786,082,261
AE	57,393,906	58,599,628	49,512,324	36,184,399	29,106,250	33,821,561	45,280,404	44,124,272	40,206,470	32,812,103	32,279,436	45,564,636	504,885,389
RTM	1,808,022	1,757,880	1,541,627	1,486,242	1,399,400	1,704,619	2,520,851	2,612,040	2,132,236	1,812,905	1,461,292	1,759,777	21,996,891
GS ND	30,942,600	30,779,155	23,701,884	23,142,596	21,727,779	20,606,524	23,285,291	26,548,263	31,022,595	29,448,634	22,099,834	28,715,077	312,020,232
GSD	72,664,057	67,124,098	67,178,954	57,999,807	55,798,177	56,627,383	68,987,185	72,921,455	89,123,716	74,101,844	63,450,654	60,353,840	806,331,170
GS HV	236,548	88,510	94,090	99,840	93,276	133,894	141,704	139,276	150,358	126,610	117,146	55,682	1,476,934
GTLV	399,731,696	383,306,994	382,682,124	333,159,553	371,472,849	417,810,450	451,291,796	466,784,852	414,528,465	400,176,858	371,390,252	341,115,069	4,733,450,958
GT3A	214,698,502	194,690,796	211,642,354	201,988,289	227,167,287	250,656,156	274,126,658	278,666,213	256,426,613	239,807,664	221,178,018	188,435,667	2,759,484,217
GT3B	21,365,063	17,450,270	19,209,787	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	211,817,147
Total	947,525,775	891,471,912	883,746,817	792,473,392	834,305,602	942,661,482	1,089,922,244	1,117,502,492	1,035,690,559	934,420,218	846,582,108	821,242,598	11,137,545,199

Growth in BSA Forecasted kWh from Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	5,687,055	1,305,277	8,058,517	(4,657,859)	5,841,507	(8,327,053)	(7,624,963)	4,423,088	(481,522)	(5,369,979)	5,308,759	10,105,003	14,267,830
AE	11,620,271	5,113,451	3,645,945	3,631,959	2,431,631	(934,887)	(2,492,939)	3,873,804	1,368,176	348,831	2,869,380	(3,137,557)	28,338,065
RTM	(74,713)	(38,593)	91,584	(18,303)	(52,440)	(198,880)	(453,468)	(512,944)	(129,396)	(270,618)	(168,013)	(357,765)	(2,183,549)
GS ND	17,084,823	12,527,353	22,480,413	(2,912,197)	(3,939,818)	(603,254)	559,110	(2,336,058)	(7,944,673)	(9,927,665)	(3,954,789)	(9,645,149)	11,388,096
GSD	46,869,138	41,282,486	50,221,929	(8,723,786)	(3,205,093)	3,217,284	(861,005)	(4,757,797)	(24,035,716)	(15,676,434)	(12,830,720)	(7,153,652)	64,346,634
GS HV	(146,869)	(2,691)	(4,448)	10,410	2,157	17,724	26,488	35,324	(8,658)	(15,133)	(19,066)	56,420	(48,342)
GTLV	(24,202,704)	(18,894,110)	(28,751,656)	34,740,705	12,212,147	(47,609)	8,535,551	2,666,843	21,371,670	14,204,579	(24,045)	43,342,665	65,154,036
GT3A	(22,870,612)	(15,978,469)	(12,847,800)	21,062,627	3,935,452	4,587,944	(1,770,235)	7,614,743	7,464,040	7,283,411	1,096,861	26,001,449	25,579,411
GT3B	(3,082,205)	(422,648)	(19,209,787)	862,814	1,574,260	2,510,736	1,432,341	1,365,023	2,473,961	1,764,923	939,854	2,425,028	(7,365,700)
Total	30,884,184	24,892,056	23,684,697	43,996,370	18,799,803	222,005	(2,649,120)	12,372,026	77,882	(7,658,085)	(6,781,779)	61,636,442	199,476,481

% Growth Over BSA Forecasted kWh for Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	3.8%	0.9%	6.3%	-3.8%	5.3%	-5.8%	-3.7%	2.1%	-0.3%	-3.9%	4.5%	7.3%	0.8%
AE	20.2%	8.7%	7.4%	10.0%	8.4%	-2.8%	-5.5%	8.8%	3.4%	1.1%	8.9%	-6.9%	5.6%
RTM	-4.1%	-2.2%	5.9%	-1.2%	-3.7%	-11.7%	-18.0%	-19.6%	-6.1%	-14.9%	-11.5%	-20.3%	-9.9%
GS ND	55.2%	40.7%	94.8%	-12.6%	-18.1%	-2.9%	2.4%	-8.8%	-25.6%	-33.7%	-17.9%	-33.6%	3.6%
GSD	64.5%	61.5%	74.8%	-15.0%	-5.7%	5.7%	-1.2%	-6.5%	-27.0%	-21.2%	-20.2%	-11.9%	8.0%
GS HV	-62.1%	-3.0%	-4.7%	10.4%	2.3%	13.2%	18.7%	25.4%	-5.8%	-12.0%	-16.3%	101.3%	-3.3%
GTLV	-6.1%	-4.9%	-7.5%	10.4%	3.3%	0.0%	1.9%	0.6%	5.2%	3.5%	0.0%	12.7%	1.4%
GT3A	-10.7%	-8.2%	-6.1%	10.4%	1.7%	1.8%	-0.6%	2.7%	2.9%	3.0%	0.5%	13.8%	0.9%
GT3B	-14.4%	-2.4%	-100.0%	5.0%	9.2%	14.7%	8.4%	8.0%	14.5%	10.3%	5.5%	14.2%	-3.5%
Total	3.3%	2.8%	2.7%	5.6%	2.3%	0.0%	-0.2%	1.1%	0.0%	-0.8%	-0.8%	7.5%	1.8%

Change > -10% and < -20%
Change > -20%

Change > 10% and < 20%
Change > 20%

Pepco DC - Monthly Bill Stabilization Adjustment Data
DC PSC Formal Case No. 1139

Comparison of Pepco DC Forecasted Distribution kWh from Monthly BSA Filings for Calendar Years 2011 and 2010

Forecasted kWh from BSA Reports - Calendar Year 2011

	Jan 11	Feb 11	Mar 11	Apr 11	May 11	Jun 11	Jul 11	Aug 11	Sep 11	Oct 11	Nov 11	Dec 11	Total
R	148,685,381	137,674,581	128,183,673	121,324,663	110,452,581	144,212,892	207,200,352	208,618,118	185,012,103	139,045,597	117,517,473	138,154,847	1,786,082,261
AE	57,393,906	58,599,628	49,512,324	36,184,399	29,106,250	33,821,561	45,280,404	44,124,272	40,206,470	32,812,103	32,279,436	45,564,636	504,885,389
RTM	1,808,022	1,757,880	1,541,627	1,486,242	1,399,400	1,704,619	2,520,851	2,612,040	2,132,236	1,812,905	1,461,292	1,759,777	21,996,891
GS ND	30,942,600	30,779,155	23,701,884	23,142,596	21,727,779	20,606,524	23,285,291	26,548,263	31,022,595	29,448,634	22,099,834	28,715,077	312,020,232
GSD	72,664,057	67,124,098	67,176,954	57,999,807	55,798,177	56,627,383	68,987,185	72,921,455	89,123,716	74,101,844	63,450,654	60,353,840	806,329,170
GS HV	236,548	88,510	94,090	99,840	93,276	133,894	141,704	139,276	150,358	126,610	117,146	55,682	1,476,934
GTLV	399,731,696	383,306,994	382,682,124	333,159,553	371,472,849	417,810,450	451,291,796	466,784,852	414,528,465	400,176,858	371,390,252	341,115,069	4,733,450,958
GT3A	214,698,502	194,690,796	211,642,354	201,988,289	227,167,287	250,656,156	274,126,658	278,666,213	256,426,613	239,807,664	221,178,018	188,435,667	2,759,484,217
GT3B	21,365,063	17,450,270	19,209,787	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	17,088,003	211,817,147
Total	947,525,775	891,471,912	883,744,817	792,473,392	834,305,602	942,661,482	1,089,922,244	1,117,502,492	1,035,690,559	934,420,218	846,582,108	821,242,598	11,137,543,199

Forecasted kWh from BSA Reports - Calendar Year 2010

	Jan 10	Feb 10	Mar 10	Apr 10	May 10	Jun 10	Jul 10	Aug 10	Sep 10	Oct 10	Nov 10	Dec 10	Total
R	148,715,983	136,566,324	128,183,673	115,861,849	110,615,864	138,304,901	196,718,832	214,077,575	195,525,177	144,443,290	113,721,237	129,970,305	1,772,705,010
AE	57,405,718	58,127,911	49,512,324	35,909,177	28,449,594	32,166,821	41,999,653	45,556,419	40,255,835	31,918,267	30,746,488	47,489,966	499,538,173
RTM	2,125,298	1,922,765	1,541,627	1,406,408	1,341,773	1,630,635	2,386,370	2,700,966	2,210,762	1,896,097	1,401,062	1,650,258	22,214,021
GS ND	24,485,177	25,146,622	23,701,884	26,072,116	23,569,090	20,585,235	25,730,687	26,431,464	31,199,659	27,220,851	15,185,568	27,264,187	296,592,540
GSD	57,499,768	54,840,501	67,176,954	64,836,616	67,189,972	56,590,855	68,197,932	71,926,734	89,551,767	77,311,045	66,404,457	73,126,880	814,653,481
GS HV	121,388	99,548	94,090	95,355	91,504	135,525	145,715	137,899	152,114	126,211	110,880	63,066	1,373,295
GTLV	404,377,380	385,806,364	382,682,124	357,916,343	373,144,963	422,900,894	464,068,148	462,168,223	419,368,982	398,916,080	351,527,795	386,468,582	4,809,345,878
GT3A	225,402,596	205,390,163	211,642,354	210,490,896	228,157,807	253,710,065	281,887,355	275,910,128	259,420,949	239,052,137	209,349,116	213,489,440	2,813,903,006
GT3B	25,260,455	22,285,849	19,209,787	18,964,849	19,686,788	22,154,226	23,376,162	21,245,639	21,557,630	19,576,179	19,708,766	22,676,527	255,702,857
Total	945,393,763	890,186,047	883,744,817	831,553,609	852,247,355	948,179,157	1,104,510,854	1,120,155,047	1,059,242,875	940,460,157	808,155,369	902,199,211	11,286,028,261

Growth in BSA Forecasted kWh from Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	(30,602)	1,108,257	-	5,462,814	(163,283)	5,907,991	10,481,520	(5,459,457)	(10,513,074)	(5,397,693)	3,796,236	8,184,542	13,377,251
AE	(11,812)	471,717	-	275,222	656,656	1,654,740	3,280,751	(1,432,147)	(49,365)	893,836	1,532,948	(1,925,330)	5,347,216
RTM	(317,276)	(164,885)	-	79,834	57,627	73,984	134,481	(88,926)	(78,526)	(83,192)	60,230	109,519	(217,130)
GS ND	6,457,423	5,632,533	-	(2,929,520)	(1,841,311)	21,289	(2,445,396)	116,799	(177,064)	2,227,783	6,914,266	1,450,890	15,427,692
GSD	15,164,289	12,283,597	-	(6,836,809)	(11,391,795)	36,528	789,253	994,721	(428,051)	(3,209,201)	(2,953,803)	(12,773,040)	(8,324,311)
GS HV	115,160	(11,038)	-	4,485	1,772	(1,631)	(4,011)	1,377	(1,756)	399	6,266	(7,384)	103,639
GTLV	(4,645,684)	(2,499,370)	-	(24,756,790)	(1,672,114)	(5,090,444)	(12,776,352)	4,616,629	(4,840,517)	1,260,778	19,862,457	(45,353,513)	(75,894,920)
GT3A	(10,704,094)	(10,699,367)	-	(8,502,607)	(990,520)	(3,053,909)	(7,760,697)	2,756,085	(2,994,336)	755,527	11,828,902	(25,053,773)	(54,418,789)
GT3B	(3,895,392)	(4,835,579)	-	(1,876,846)	(2,598,785)	(5,066,223)	(6,288,159)	(4,157,636)	(4,469,627)	(2,488,176)	(2,620,763)	(5,588,524)	(43,885,710)
Total	2,132,012	1,285,865	-	(39,080,217)	(17,941,753)	(5,517,675)	(14,588,610)	(2,652,555)	(23,552,316)	(6,039,939)	38,426,739	(80,956,613)	(148,485,062)

% Growth Over BSA Forecasted kWh for Comparable Month of Prior Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
R	0.0%	0.8%	0.0%	4.7%	-0.1%	4.3%	5.3%	-2.6%	-5.4%	-3.7%	3.3%	6.3%	0.8%
AE	0.0%	0.8%	0.0%	0.8%	2.3%	5.1%	7.8%	-3.1%	-0.1%	2.8%	5.0%	-4.1%	1.1%
RTM	-14.9%	-8.6%	0.0%	5.7%	4.3%	4.5%	5.6%	-3.3%	-3.6%	-4.4%	4.3%	6.6%	-1.0%
GS ND	26.4%	22.4%	0.0%	-11.2%	-7.8%	0.1%	-9.5%	0.4%	-0.6%	8.2%	45.5%	5.3%	5.2%
GSD	26.4%	22.4%	0.0%	-10.5%	-17.0%	0.1%	1.2%	1.4%	-0.5%	-4.2%	-4.4%	-17.5%	-1.0%
GS HV	94.9%	-11.1%	0.0%	4.7%	1.9%	-1.2%	-2.8%	1.0%	-1.2%	0.3%	5.7%	-11.7%	7.5%
GTLV	-1.1%	-0.6%	0.0%	-6.9%	-0.4%	-1.2%	-2.8%	1.0%	-1.2%	0.3%	5.7%	-11.7%	-1.6%
GT3A	-4.7%	-5.2%	0.0%	-4.0%	-0.4%	-1.2%	-2.8%	1.0%	-1.2%	0.3%	5.7%	-11.7%	-1.9%
GT3B	-15.4%	-21.7%	0.0%	-9.9%	-13.2%	-22.9%	-26.9%	-19.6%	-20.7%	-12.7%	-13.3%	-24.6%	-17.2%
Total	0.2%	0.1%	0.0%	-4.7%	-2.1%	-0.6%	-1.3%	-0.2%	-2.2%	-0.6%	4.8%	-9.0%	-1.3%

Change > -10% and < -20%
Change > -20%

Change > 10% and < 20%
Change > 20%

Potomac Electric Power Company

DC PSC Formal Case No. 1139

Rate Schedule GSD

Month	Year	Reported Customer Count	Base Rate Revenue Per Cust	Allowed Revenue	Actual Monthly Revenue	Over (Under) Collection	Revenue Per Cust
Dec	2013	5,280	$ 423.67	$ 2,236,977.60	$ 1,895,431.96	$ (341,545.64)	$ 358.98
Jan	2014	5,351	$ 465.28	$ 2,489,713.28	$ 2,106,320.82	$ (383,392.46)	$ 393.63
Feb	2014	5,333	$ 415.50	$ 2,215,861.50	$ 1,923,457.69	$ (292,403.81)	$ 360.67
Mar	2014	5,365	$ 397.62	$ 2,133,231.30	$ 2,046,029.27	$ (87,202.03)	$ 381.37
Apr	2014	5,373	$ 401.28	$ 2,156,077.44	$ 1,802,717.38	$ (353,360.06)	$ 335.51
May	2014	5,385	$ 424.24	$ 2,284,532.40	$ 1,807,355.98	$ (477,176.42)	$ 335.63
Jun	2014	5,219	$ 577.81	$ 3,015,590.39	$ 2,930,991.86	$ (84,598.53)	$ 561.60
Jul	2014	5,177	$ 644.19	$ 3,334,971.63	$ 3,064,075.29	$ (270,896.34)	$ 591.86
Aug	2014	5,186	$ 663.06	$ 3,438,629.16	$ 3,528,199.05	$ 89,569.89	$ 680.33
Sep	2014	5,214	$ 628.24	$ 3,275,643.36	$ 3,642,490.21	$ 366,846.85	$ 698.60
Oct	2014	5,241	$ 556.09	$ 2,914,467.69	$ 2,959,618.63	$ 45,150.94	$ 564.70
Nov	2014	5,250	$ 409.86	$ 2,151,765.00	$ 2,363,091.98	$ 211,326.98	$ 450.11
Dec	2014	5,287	$ 445.21	$ 2,353,825.27	$ 2,654,925.35	$ 301,100.08	$ 502.16
Jan	2015	4,760	$ 468.31	$ 2,229,155.60	$ 3,778,015.19	$ 1,548,859.59	$ 793.70
Feb	2015	5,631	$ 426.11	$ 2,399,425.41	$ 2,828,989.25	$ 429,563.84	$ 502.40
Mar	2015	5,215	$ 449.27	$ 2,342,943.05	$ 2,311,745.26	$ (31,197.79)	$ 443.29
Apr	2015	5,402	$ 409.94	$ 2,214,495.88	$ 2,765,099.62	$ 550,603.74	$ 511.87
May	2015	5,225	$ 424.24	$ 2,216,654.00	$ 2,511,124.83	$ 294,470.83	$ 480.60
Jun	2015	5,179	$ 577.81	$ 2,992,477.99	$ 3,303,035.14	$ 310,557.15	$ 637.77
Jul	2015	5,537	$ 644.19	$ 3,566,880.03	$ 3,729,321.48	$ 162,441.45	$ 673.53
Aug	2015	5,219	$ 663.06	$ 3,460,510.14	$ 3,433,820.53	$ (26,689.61)	$ 657.95
Sep	2015	5,262	$ 628.24	$ 3,305,798.88	$ 3,435,280.21	$ 129,481.33	$ 652.85
Oct	2015	5,445	$ 556.09	$ 3,027,910.05	$ 3,320,307.97	$ 292,397.92	$ 609.79
Nov	2015	5,289	$ 409.86	$ 2,167,749.54	$ 2,368,999.25	$ 201,249.71	$ 447.91
Dec	2015	5,192	$ 445.21	$ 2,311,530.32	$ 3,093,630.91	$ 782,100.59	$ 595.85
Jan	2016	5,460	$ 468.31	$ 2,556,972.60	$ 2,980,776.51	$ 423,803.91	$ 545.93
Feb	2016	5,472	$ 426.11	$ 2,331,673.92	$ 2,433,231.76	$ 101,557.84	$ 444.67
Mar	2016	5,664	$ 449.27	$ 2,544,665.28	$ 2,781,297.57	$ 236,632.29	$ 491.05
Apr	2016	5,337	$ 409.94	$ 2,187,849.78	$ 2,192,101.21	$ 4,251.43	$ 410.74
May	2016	5,212	$ 424.24	$ 2,211,138.88	$ 2,380,598.98	$ 169,460.10	$ 456.75
Jun	2016	4,835	$ 577.81	$ 2,793,711.35	$ 3,120,837.94	$ 327,126.59	$ 645.47
Jul	2016	4,720	$ 644.19	$ 3,040,576.80	$ 3,478,097.42	$ 437,520.62	$ 736.89
Aug	2016	5,397	$ 663.06	$ 3,578,534.82	$ 4,089,841.89	$ 511,307.07	$ 757.80
Sep	2016	4,917	$ 628.24	$ 3,089,056.08	$ 3,960,299.72	$ 871,243.64	$ 805.43
Oct	2016	5,194	$ 556.09	$ 2,888,331.46	$ 3,360,232.70	$ 471,901.24	$ 646.95

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Rate Schedule GT LV

Month	Year	Reported Customer Count	Base Rate Revenue Per Cust	Allowed Revenue	Actual Monthly Revenue	Over (Under) Collection	Revenue Per Cust
Dec	2013	2,881	$ 4,407.76	$ 12,698,757	$ 11,860,004	$ (838,752)	$ 4,117
Jan	2014	2,912	$ 4,635.73	$ 13,499,246	$ 12,466,955	$ (1,032,290)	$ 4,281
Feb	2014	2,910	$ 4,361.05	$ 12,690,656	$ 12,330,921	$ (359,735)	$ 4,237
Mar	2014	2,924	$ 4,299.37	$ 12,571,358	$ 12,317,509	$ (253,848)	$ 4,213
Apr	2014	2,933	$ 4,393.80	$ 12,887,015	$ 11,365,448	$ (1,521,567)	$ 3,875
May	2014	2,943	$ 4,572.33	$ 13,456,367	$ 12,225,073	$ (1,231,295)	$ 4,154
Jun	2014	2,951	$ 4,899.39	$ 14,458,100	$ 13,350,651	$ (1,107,449)	$ 4,524
Jul	2014	2,952	$ 5,209.88	$ 15,379,566	$ 14,317,288	$ (1,062,278)	$ 4,850
Aug	2014	2,964	$ 5,252.39	$ 15,568,084	$ 13,940,749	$ (1,627,335)	$ 4,703
Sep	2014	2,970	$ 5,127.41	$ 15,228,408	$ 14,117,794	$ (1,110,614)	$ 4,753
Oct	2014	2,971	$ 4,670.84	$ 13,877,066	$ 12,760,318	$ (1,116,748)	$ 4,295
Nov	2014	2,970	$ 4,468.00	$ 13,269,960	$ 12,323,251	$ (946,709)	$ 4,149
Dec	2014	2,992	$ 4,550.01	$ 13,613,630	$ 13,411,240	$ (202,390)	$ 4,482
Jan	2015	2,343	$ 4,833.29	$ 11,324,398	$ 8,573,619	$ (2,750,779)	$ 3,659
Feb	2015	3,325	$ 4,633.18	$ 15,405,324	$ 14,306,482	$ (1,098,842)	$ 4,303
Mar	2015	2,880	$ 4,631.49	$ 13,338,691	$ 13,482,568	$ 143,877	$ 4,681
Apr	2015	3,129	$ 4,560.76	$ 14,270,618	$ 12,903,075	$ (1,367,543)	$ 4,124
May	2015	2,975	$ 4,572.33	$ 13,602,682	$ 12,894,747	$ (707,935)	$ 4,334
Jun	2015	2,759	$ 4,899.39	$ 13,517,417	$ 10,941,247	$ (2,576,170)	$ 3,966
Jul	2015	3,165	$ 5,209.88	$ 16,489,270	$ 16,772,045	$ 282,774	$ 5,299
Aug	2015	3,063	$ 5,252.39	$ 16,088,071	$ 14,467,040	$ (1,621,031)	$ 4,723
Sep	2015	3,127	$ 5,127.41	$ 16,033,411	$ 15,136,155	$ (897,256)	$ 4,840
Oct	2015	3,011	$ 4,670.84	$ 14,063,899	$ 13,102,256	$ (961,643)	$ 4,351
Nov	2015	3,052	$ 4,468.00	$ 13,636,336	$ 12,804,933	$ (831,403)	$ 4,196
Dec	2015	2,880	$ 4,550.01	$ 13,104,029	$ 11,846,348	$ (1,257,681)	$ 4,113
Jan	2016	3,030	$ 4,833.29	$ 14,644,869	$ 12,861,019	$ (1,783,850)	$ 4,245
Feb	2016	3,179	$ 4,633.18	$ 14,728,879	$ 14,145,341	$ (583,538)	$ 4,450
Mar	2016	3,303	$ 4,631.49	$ 15,297,811	$ 15,174,904	$ (122,908)	$ 4,594
Apr	2016	2,892	$ 4,560.76	$ 13,189,718	$ 11,561,493	$ (1,628,225)	$ 3,998
May	2016	2,943	$ 4,572.33	$ 13,456,367	$ 12,254,893	$ (1,201,475)	$ 4,164
Jun	2016	3,321	$ 4,899.39	$ 16,270,874	$ 13,702,624	$ (2,568,251)	$ 4,126
Jul	2016	3,092	$ 5,209.88	$ 16,108,949	$ 13,095,341	$ (3,013,608)	$ 4,235
Aug	2016	3,511	$ 5,252.39	$ 18,441,141	$ 16,158,578	$ (2,282,563)	$ 4,602
Sep	2016	3,098	$ 5,127.41	$ 15,884,716	$ 13,621,002	$ (2,263,714)	$ 4,397
Oct	2016	3,246	$ 4,670.84	$ 15,161,547	$ 12,823,121	$ (2,338,426)	$ 3,950

Potomac Electric Power Company
DCPSC Formal Case No. 1139

Pepco DC - Monthly Bill Stabilization Adjustment Data
Rate Schedule GT3A

Month	Year	Reported Customer Count	Base Rate Revenue Per Cust	Allowed Revenue	Actual Monthly Revenue	Over (Under) Collection	Revenue Per Cust
Dec	2013	148	$ 23,440	$ 3,469,182	$ 3,164,656	$ (304,526)	$ 21,383
Jan	2014	148	$ 21,720	$ 3,214,585	$ 2,982,485	$ (232,100)	$ 20,152
Feb	2014	147	$ 21,114	$ 3,103,723	$ 2,870,772	$ (232,950)	$ 19,529
Mar	2014	148	$ 22,399	$ 3,315,042	$ 2,877,140	$ (437,902)	$ 19,440
Apr	2014	148	$ 25,329	$ 3,748,702	$ 3,071,796	$ (676,906)	$ 20,755
May	2014	147	$ 25,905	$ 3,808,054	$ 3,543,613	$ (264,441)	$ 24,106
Jun	2014	143	$ 28,881	$ 4,129,916	$ 3,874,526	$ (255,390)	$ 27,095
Jul	2014	148	$ 30,072	$ 4,450,709	$ 4,356,338	$ (94,372)	$ 29,435
Aug	2014	147	$ 31,084	$ 4,569,322	$ 4,103,017	$ (466,305)	$ 27,912
Sep	2014	147	$ 30,020	$ 4,412,871	$ 4,130,301	$ (282,570)	$ 28,097
Oct	2014	148	$ 27,935	$ 4,134,413	$ 3,850,526	$ (283,886)	$ 26,017
Nov	2014	148	$ 24,922	$ 3,688,407	$ 3,523,029	$ (165,378)	$ 23,804
Dec	2014	149	$ 23,494	$ 3,500,672	$ 3,346,714	$ (153,957)	$ 22,461
Jan	2015	47	$ 23,663	$ 1,112,166	$ 843,600	$ (268,566)	$ 17,949
Feb	2015	143	$ 23,201	$ 3,317,683	$ 2,799,986	$ (517,697)	$ 19,580
Mar	2015	160	$ 23,569	$ 3,771,082	$ 3,759,373	$ (11,709)	$ 23,496
Apr	2015	146	$ 26,036	$ 3,801,260	$ 2,991,200	$ (810,060)	$ 20,488
May	2015	152	$ 25,905	$ 3,937,580	$ 3,548,152	$ (389,428)	$ 23,343
Jun	2015	119	$ 28,881	$ 3,436,783	$ 3,454,769	$ 17,986	$ 29,032
Jul	2015	167	$ 30,072	$ 5,022,084	$ 4,432,949	$ (589,135)	$ 26,545
Aug	2015	187	$ 31,084	$ 5,812,674	$ 5,088,365	$ (724,309)	$ 27,211
Sep	2015	148	$ 30,020	$ 4,442,890	$ 4,052,012	$ (390,878)	$ 27,378
Oct	2015	148	$ 27,935	$ 4,134,413	$ 3,535,858	$ (598,555)	$ 23,891
Nov	2015	160	$ 24,922	$ 3,987,467	$ 4,211,478	$ 224,011	$ 26,322
Dec	2015	142	$ 23,494	$ 3,336,210	$ 3,279,182	$ (57,028)	$ 23,093
Jan	2016	166	$ 23,663	$ 3,928,075	$ 3,786,006	$ (142,068)	$ 22,807
Feb	2016	156	$ 23,201	$ 3,619,290	$ 3,055,870	$ (563,420)	$ 19,589
Mar	2016	198	$ 23,569	$ 4,666,713	$ 3,878,405	$ (788,308)	$ 19,588
Apr	2016	144	$ 26,036	$ 3,749,188	$ 3,064,586	$ (684,602)	$ 21,282
May	2016	132	$ 25,905	$ 3,419,477	$ 3,663,052	$ 243,575	$ 27,750
Jun	2016	160	$ 28,881	$ 4,620,885	$ 3,573,557	$ (1,047,328)	$ 22,335
Jul	2016	153	$ 30,072	$ 4,601,071	$ 3,668,350	$ (932,722)	$ 23,976
Aug	2016	183	$ 31,084	$ 5,688,339	$ 5,430,130	$ (258,209)	$ 29,673
Sep	2016	132	$ 30,020	$ 3,962,578	$ 3,569,442	$ (393,136)	$ 27,041
Oct	2016	150	$ 27,935	$ 4,190,283	$ 3,759,595	$ (430,688)	$ 25,064

Potomac Electric Power Company

DCPSC Formal Case No. 1139

Pepco Actual and Weather Corrected KWh

			MMA-AE Test Year kWh		GT-3B Test Year kWh	
Ln No	Month	Year	Reported Actuals	Estimated Weather Corrected	Reported Actuals	Estimated Weather Corrected
1	Apr	2015	(283,846)	(254,644)	(35,995,663)	(35,948,626)
2	May	2015	1,551,856	1,547,983	99,439,285	99,459,656
3	Jun	2015	(1,764,190)	(1,804,690)	6,439,643	6,409,507
4	Jul	2015	2,752,259	2,737,180	(31,916,310)	(31,927,531)
5	Aug	2015	1,133,027	1,102,702	0	(22,565)
6	Sep	2015	(238,442)	(262,066)	0	(17,579)
7	Oct	2015	1,111,290	1,107,948	116,492,156	116,490,154
8	Nov	2015	92,993	135,597	11,692,831	11,761,457
9	Dec	2015	499,410	597,484	9,879,274	10,037,249
10	Jan	2016	367,787	479,851	17,620,570	17,741,548
11	Feb	2016	1,291,366	1,285,269	12,333,259	12,326,677
12	Mar	2016	268,989	374,215	31,194,294	31,307,890
13	Total		6,782,499	7,046,830	237,179,339	237,617,837

From Pepco 21 Day Compliance Filing, Order 17424, Attachment 2.

Potomac Electric Power Company

DC PSC Formal Case No. 1139

DC Weather Normalized Sales and Revenue Adjustments

From Exhibit Pepco (G)-1

Ln No	Rate Schedule	Test Year Actual kWh	WN kWh Adj	Pepco WN kWh	Pepco WN Rev Adjustment	Correct Revenue Adj
1	R	1,496,069,023	(23,971,986)	1,469,067,037	$ (531,268)	$ (726,717)
2	AE	552,614,938	23,938,605	576,553,543	$ 202,161	$ 206,366
3	MMA	324,096,713	(6,969,936)	317,126,777	(171,527)	$ (2,592,477)
4	RTM	17,584,415	(159,612)	17,424,803	$ (6,862)	$ (6,862)
5	Total Res	2,390,365,089	(7,162,929)	2,380,172,160	$ (507,495)	$ (3,119,690)
6	GS-ND	309,977,431	1,042,188	311,019,619	$ (6,731)	$ 6,992
7	T	19,037,695	271,915	19,309,610	$ 13,963	$ 13,963
8	GSD-LV	635,741,579	(5,243,611)	630,497,968	$ (278,808)	$ (278,808)
9	GSD-3A	1,771,511	(13,473)	1,758,038	$ (223)	$ (223)
10	GT-LV	4,766,416,593	(15,012,273)	4,751,404,320	$ (129,706)	$ (129,706)
11	GT-3A	2,556,599,062	(37,509,066)	2,519,089,996	$ (181,169)	$ (106,443)
12	GT-3B	na	na	na	na	na
13	TN	2,650,948	-	2,650,948	$ -	$ -
14	Total Com	8,292,194,819	(56,464,320)	8,235,730,499	$ (582,675)	$ (494,225)
15	SL	na	na	na	na	na
16	TS	na	na	na	na	na
17	METRO	na	na	na	na	na
18	DC Total	10,682,559,908	(63,627,249)	10,615,902,659	$ (1,090,170)	$ (3,613,916)
19	Difference					$ (2,523,746)

Potomac Electric Power Company
DC PSC Formal Case No. 1139

Pepco-DC Historical Rate Requests and Approved Increases
($ in millions)

Ln No	Formal Case Number A	Date Filed B	Order No. C	Order Issue Date D	Pepco Initial Rev Incr Request E	Revenue Increase Approved H	% of Initial Request Approved I	Pepco Requested ROE J	Approved ROE K	Reduction from Pepco ROE Request L
1	1139	6/30/2016			$ 85.48			10.60%		
2	1103	3/8/2013	17424	3/26/2014	$ 52.10	$ 23.45	45%	10.25%	9.40%	0.85%
3	1087	7/8/2011	16930	9/27/2012	$ 42.10	$ 24.38	58%	10.75%	9.50%	1.25%
4	1076	5/22/2009	15710	3/2/2010	$ 51.70	$ 19.83	38%	10.75%	9.63%	1.12%
5	1053	12/12/2006	14712	1/30/2008	$ 50.50	$ 28.29	56%	11.00%	10.00%	1.00%
6	Average				$ 49.10		49%			1.06%

Potomac Electric Power Company
DC PSC Formal Case No. 1139

AOBA Proposed Revenue Increase Distribution and Applcation of Base Rate Credits
At 50% of Pepco's Original Revenue Increase Request

Ln No		Operating Income for ROR	Rate Base	ROR at Present Rates	Class UROR	Revenue At Present Rates	Across the Board Increase	Revenue Conversion Factor	Adj Oper Income	ATB ROR	Adjusted Rev Incr Distribution	% Revenue Increase	% of Total Increase	AOBA Rev Dist ROR	UROR	Est Annual Credits Required
	RESIDENTIAL															
1	R	(20,031,782)	437,508,630	-4.58%	(0.88)	47,302,272	5,592,339	1.6906	(16,723,914)	-3.82%	13,980,847	29.6%	32.71%	-2.7%	(0.36)	8,388,508
2	AE	(6,003,619)	140,743,574	-4.27%	(0.82)	17,727,776	2,095,877	1.6906	(4,763,908)	-3.38%	5,239,692	29.6%	12.26%	-2.1%	(0.28)	3,143,815
3	RTM	312,568	3,509,909	8.91%	1.71	878,235	103,830	1.6906	373,983	10.66%	68,971	7.853%	0.16%	10.1%	1.34	0
4	MMA	6,664,968	47,971,529	13.89%	2.67	14,626,702	1,729,250	1.6906	7,687,820	16.03%	1,148,696	7.853%	2.69%	15.3%	2.04	1,148,696
5	**TOTAL RESIDENTIAL**	(19,057,865)	629,733,642	-3.03%	(0.58)	80,534,985	9,521,295	1.6906	(13,426,019)	-2.13%	20,438,205	25.378%	47.82%	-1.1%	(0.15)	12,681,019
	NON-RESIDENTIAL	(26,035,401)	578,252,204	-4.50%	(0.87)	65,030,048	7,688,215	1.6906	(21,487,822)	-3.72%	19,220,538	23.6%	44.97%	-2.5%	(0.34)	0
	General Service															
6	GS-LV	15,567,999	176,366,842	8.83%	1.70	46,876,274	5,541,975	1.6906	18,846,077	10.69%	3,681,389	7.853%	8.61%	10.1%	1.34	0
7	GS-HV	32,724	142,222	23.01%	4.43	67,423	7,971	1.6906	37,439	26.32%	(10,200)	-15.128%	-0.02%	18.8%	2.50	0
8	Total GS	15,600,723	176,509,064	8.84%	1.70	46,943,697	5,549,946	1.6906	18,883,516	10.70%	3,671,189	7.820%	8.59%		-	0
	General Time-Metered Service															
9	GT-LV	69,179,601	704,142,789	9.82%	1.89	175,427,390	20,740,005	1.6906	81,447,314	11.57%	13,777,043	7.853%	32.24%	11.0%	1.46	0
10	GT-3A	21,917,348	173,489,640	12.63%	2.43	50,077,679	5,920,463	1.6906	25,419,302	14.65%	3,932,808	7.853%	9.20%	14.0%	1.86	0
11	GT-3B	233,777	1,849,898	12.64%	2.43	573,772	67,835	1.6906	273,901	14.81%	45,061	7.853%	0.11%	14.1%	1.88	0
12	Total GT	91,330,726	879,482,327	10.38%	2.00	226,078,841	26,728,302	1.6906	107,140,517	12.18%	17,754,912	7.853%	41.54%		-	0
13	Metro	2,409,159	27,891,902	8.64%	1.66	6,442,548	761,674	1.6906	2,859,689	10.25%	568,069	8.817%	1.33%	9.8%	1.31	0
	Street Lighting & Traffic Signals															
14	SL-E	(455,801)	12,326,624	-3.70%	(0.71)	492,012	58,168	1.6906	(421,394)	-3.42%	145,421	29.556%	0.34%	-3.0%	(0.40)	87,253
15	TS	105,540	787,001	13.41%	2.58	230,480	27,249	1.6906	121,658	15.46%	18,101	7.853%	0.04%	14.8%	1.97	0
16	SL-S	(27,557)	4,890,966	-0.56%	(0.11)	660,105	78,041	1.6906	18,604	0.38%	195,103	29.556%	0.46%	1.8%	0.24	117,062
17	Total SL & TS	(377,818)	18,004,591	-2.10%	(0.40)	1,382,597	163,458	1.6906	(281,132)	-1.56%	358,625	25.938%	0.84%		-	204,315
18	TN Service	67,532	194,532	34.72%	6.68	116,928	13,824	1.6906	75,709	38.92%	(52,500)	-44.899%	-0.12%	18.8%	2.50	0
19	**TOTAL NON-RESIDENTIAL**	109,030,322	1,102,082,416	9.89%	1.90	280,964,611	33,217,205	1.6906	128,678,299	11.68%	22,300,294	7.937%	52.18%		-	204,315
20	**TOTAL SYSTEM**	**89,972,457**	**1,731,816,058**	5.20%	1.00	**361,499,596**	**42,738,500**	1.6906	**115,252,280**	6.65%	**42,738,500**		100.00%		-	**12,885,333**

BRUCE R. OLIVER

Revilo Hill Associates, Inc.
7103 Laketree Drive
Fairfax Station, Virginia 22039
(703) 569-6480

EXPERIENCE

Over 40 years of experience specializing in the areas of utility rates, energy, and regulatory policy. Offers unusual depth and breadth in his understanding of energy and utility industries which leads to creative and effective resolution of rate issues. Has presented expert testimony in regulatory proceedings in more than 300 proceedings before regulatory commissions in 24 jurisdictions, and has served a diverse group of clients on issues encompassing a wide range of energy and utility-related activities. Assists clients in the assessment of competitive energy markets for retail services and in the negotiation of contracts for the purchase of such services. Clients have included commercial and industrial energy users, hospitals and universities, state regulatory commissions, utilities, consumer advocates, municipal governments, federal agencies, and suppliers of equipment and services to utility markets.

1985- Present — Revilo Hill Associates, Inc.
President and CEO

Directs the firm's consulting practice, with specialization in the areas of industrial economics, energy, utilities and regulatory policy. Provides expert testimony in regulatory proceedings. Assists individual commercial and institutional customers in the competitive procurement of energy services and resolution of utility service and billing issues. Regulatory work includes participation in electric, gas, water and sewer utility rate and policy matters, with particular specialization in the areas of utility costs of service, rate structure, rate of return, utility planning, and forecasting. Examples of recent projects include:

- Investigation of utility merger issues including ring-fencing, costs to achieve, estimated merger benefits, and allocation of merger benefits among customers.

- Examination of utility proposals undergrounding overhead electric distribution facilities and the recovery of costs for undergrounding activities.

- Investigation of utility Grid Resiliency and associated cost recovery proposals.

- Assessment of plans for accelerated replacement of distribution mains by an LDC.

- Evaluation of utility proposals for the deployment of Advanced Metering Infrastructure (AMI) and the development of dynamic pricing rates to be implemented using AMI equipment.

- Assistance to large commercial and institutional utility customers in the procurement of competitive electricity and natural gas services.

- Analysis of utility revenue decoupling proposals including assessment of the cost of service and rate impacts of such proposals and the development of appropriate tariff language for such proposals.

- Investigation of matters relating to a utility outsourcing of significant components of its Administrative and General and Customer Service activities.

- Assessments of a utility's long-range gas supply planning and the prudence of its gas procurement activities.

- Evaluation of the merits of the proposed utility mergers including assessments of impacts on customers and on competition.

- Strategic analysis and policy guidance for a major commercial consumer group in the development and presentation of positions before legislative and regulatory bodies regarding electric and gas regulatory issues.

- Development of Asset Management incentive programs for natural gas distribution utilities.

- Investigation and preparation of a report on the causes of large heating oil price increases for the Attorney General of a New England state.

- Participation as a member of a three-person panel hearing a gas marketer complaint of anti-competitive behavior by a local gas distribution utility in its provision of unbundled gas transportation services.

- Preparation of cost allocation studies and rate structure proposals for electric, gas, water and wastewater utility regulatory proceedings; and

- Analysis of proposals for restructuring and the unbundling of rates for local gas distribution companies, and negotiated terms, conditions, and pricing for restructured utility services.

2000-Present AOBA Alliance, Inc.
Director and Chief Economist

Key technical advisor to one of the nation's largest and most successful customer-based energy aggregation programs. Assists non-residential customers in the Washington, D.C. area in the procurement of competitive retail energy services, including the evaluation and negotiation of contract terms for competitive electricity, natural gas, energy information services. Monitors energy markets and keeps participants informed regarding energy market developments and pricing trends. Focused primarily on the commercial building industry, the AOBA Alliance, Inc. serves more than 7,000 electric and natural gas accounts, over 2.5 billion kWh per year, and over 600 MW of electrical peak load.

1981-85 Resource Dynamics Corporation
Principal and Vice President

Responsible for the firm's activities in the areas of energy pricing, utility rates and regulatory policy. Provided expert testimony before utility regulatory commissions on issues relating to costs of service, rate design, load management, load research, fuel price forecasting, utility costing analyses, and cost allocation methods. Evaluated utility fuel procurement practices, fuel price forecasts, and price forecasting methodologies. Contributed to modeling efforts relating to the estimation of national and regional electric utility load curves and coal market prices. Participated in the development handbooks for cogeneration feasibility assessment.

1980-81 Potomac Electric Power Company
Manager of Rate Research Department

Directed the development of all rate related programs. Supervised the costing, design and analysis of traditional and innovative rates (including time-of-use, load management and cogeneration tariffs). Also was responsible for corporate revenue forecasting activities, as well as the development of marginal and avoided cost studies.

1979-80 Pacific Gas and Electric Company
Rate Experimentation Supervisor

Responsible for design, implementation and analysis of innovative rate programs for both gas and electric service. Developed programs for curtailable service; cogeneration; conservation; residential load cycling; and commercial, industrial, and agricultural time-of- use rates. Directed analyses of time-of-use and lifeline price elasticities and development of marginal and avoided costing methods.

1973-79 ICF Incorporated
Project Manager

Specialized in energy policy and utility regulatory analyses. Performed detailed analysis of U.S. petroleum, natural gas, coal and electric utility industries. Provided expert testimony on utility rate issues. Designed experimental rates for federally funded time-of-use rate and load management programs in North Carolina. Provided technical support to the DOE Regulatory Intervention Program. Contributed to the design and development of the National Coal Model, and prepared forecasts of low sulfur fuel availability for utility markets.

1972-73 U.S. Cost-of-Living Council - Pay Board
Labor Economist

Served in the Office of the Chief Economist. Responsible for macroeconomic analyses of Board decisions, and for the development data systems to support assessments of the impacts of Board decisions and the reporting of aggregate statistics on wage increases granted by the Board.

EDUCATION

1972 M.A., Economics, Virginia Polytechnic Institute and State University

1970 B.A., Economics, Virginia Polytechnic Institute and State University

RATE CASE PARTICIPATION

Alberta, Canada

Canadian Western Natural Gas	1998 General Rate Application
NOVA Gas Transmission Ltd.	1995 GRA, Phase II
Canadian Western Natural Gas	Core Market Direct Purchase
Northwestern Utilities	Core Market Direct Purchase
TransAlta Utilities Corp.	Load Retention Rate Offering
Alberta Power Ltd.	1993 General Rate Application

Arizona

Southwest Gas Corporation	Docket No. U-1551-93-272
Sun City Water Company	Docket No. U-1656-91-134
Havasu Water Company	Docket No. U-2013-91-133
Arizona Water Company	Docket No. U-1445-91-227

California	
Pacific Gas & Electric Company	Application No. 58089
Connecticut	
Southern Connecticut Gas Company	Docket No. 89-09-06
Connecticut Light & Power Company	Docket No. 87-07-01
Delaware	
Chesapeake Utilities Corporation	Docket No. 95 - 73
Delmarva Power & Light Company	Docket No. 94 - 141
Delmarva Power & Light Company	Docket No. 94 - 129
Delaware Electric Cooperative	Docket No. 94 - 100
Delmarva Power & Light Company	Docket No. 92 - 85
Delmarva Power & Light Company	Docket No. 92 - 71F
Delaware Electric Cooperative	Docket No. 91 - 37
Delmarva Power & Light Company	Docket No. 91 - 24
Delmarva Power & Light Company	Docket No. 91 - 20
Delmarva Power & Light Company	Docket No. 90 - 31
Delmarva Power & Light Company	Docket No. 90 - 21
Delmarva Power & Light Company	Docket No. 89 - 26
Chesapeake Utilities Corporation	Docket No. 88 - 39F
Delmarva Power & Light Company	Docket No. 88 - 34
Delmarva Power & Light Company	Docket No. 88 - 32, Phase 2
Delmarva Power & Light Company	Docket No. 88 - 32
Delaware Electric Cooperative	Docket No. 87 - 34, Phase 2
Delaware Electric Cooperative	Docket No. 87 - 34
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 5
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 4
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 3
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 2
Delmarva Power & Light Company	Docket No. 87 - 9
Delmarva Power & Light Company	Docket No. 86 - 43
Delmarva Power & Light Company	Docket No. 86 - 24
District of Columbia	
Washington Gas Light Company	Case No. 1137
Potomac Electric Power Company	Case No. 1121
Exelon – Pepco Merger	Case No. 1119
Potomac Electric Power Company	Case No. 1116
Washington Gas Light Company	Case No. 1115
Potomac Electric Power Company	Case No. 1103
Washington Gas Light Company	Case No. 1093
Potomac Electric Power Company	Case No. 1087
Washington Gas Light Company	Case No. 1079
Potomac Electric Power Company	Case No. 1076
Potomac Electric Power Company	Case No. 1056

Washington Gas Light Company	Case No. 1054
Potomac Electric Power Company	Case No. 1053, Phase II
Potomac Electric Power Company	Case No. 1053
Washington Gas Light Company	Case No. 1016
Potomac Electric Power/Conectiv Merger	Case No. 1002
Washington Gas Light Company	Case No. 989
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Case No. 951
Potomac Electric Power Company	Case No. 945
Potomac Electric Power Company	Case No. 939
Washington Gas Light Company	Case No. 934
Washington Gas Light Company	Case No. 922
District of Columbia Natural Gas	Case No. 890
Potomac Electric Power Company	Case No. 889
Potomac Electric Power Company	Case No. 869
District of Columbia Natural Gas	Case No. 845
District of Columbia Natural Gas	Case No. 840
Potomac Electric Power Company	Case No. 834
Potomac Electric Power Company	Case No. 813, Phase II
Potomac Electric Power Company	Case No. 813
Washington Gas Light Company	Case No. 787
Potomac Electric Power Company	Case No. 785
Potomac Electric Power Company	Case No. 759, Phases III
Potomac Electric Power Company	Case No. 759, Phases II
Potomac Electric Power Company	Case No. 759, Phases I
Potomac Electric Power Company	Case No. 758
Guam	
Guam Power Authority	Docket No. 11-090, Ph II
Guam Power Authority	Docket No. 11-090
Guam Power Authority	Docket No. 07-010
Guam Power Authority	Docket No. 98-002
Guam Power Authority	Docket No. 96-004
Guam Power Authority	Docket No. 95-001
Guam Power Authority	Docket No. 94-001
Guam Power Authority	Docket No. 92-002
Guam Power Authority	Docket No. 89-002 A,B,C
Illinois	
Commonwealth Edison Company	Docket No. 86-0128
Maryland	
Potomac Electric Power Company	Case No. 9418
Exelon – Pepco Merger	Case No. 9361
Potomac Electric Power Company	Case No. 9336
Washington Gas Light Company	Case No. 9335

Washington Gas Light Company	Case No. 9322
Potomac Electric Power Company	Case No. 9311
Potomac Electric Power Company	Case No. 9286
Washington Gas Light Company	Case No. 9267
Potomac Electric Power Company	Case No. 9217
Potomac Electric Power Company	Case No. 9207
Washington Gas Light Company	Case No. 9158
Washington Gas Light Company	Case No. 9104, Phase II
Washington Gas Light Company	Case No. 9104
Potomac Electric Power Company	Case No. 9092, Phase II
Potomac Electric Power Company	Case No. 9092
Standard Offer Service Docket	Case No. 9063
Standard Offer Service Docket	Case No. 9056
Standard Offer Service Docket	Case No. 9037
Potomac Electric Power Company	Case No. 8895
Washington Gas Light Company	Case No. 8991
Washington Gas Light Company	Case No. 8959
Washington Gas Light Company	Case No. 8920, Phase II
Washington Gas Light Company	Case No. 8920
Potomac Electric Power Company	Case No. 8895
Potomac Electric Power Company	Case No. 8890
Potomac Electric Power Company	Case No. 8791
Potomac Electric Power Company	Case No. 8773
Generic Electric Industry Restructuring	Case No. 8738
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Case No. 8725
Washington Gas Light Company	Case No. 8545
Potomac Electric Power Company	Case No. 8315
Potomac Electric Power Company	Case No. 8251
Maryland Natural Gas	Case No. 8191
Potomac Electric Power Company	Case No. 8162
Maryland Natural Gas	Case No. 8119
Potomac Electric Power Company	Case No. 8079
Baltimore Gas & Electric Company	Case No. 8070
Maryland Natural Gas	Case No. 8060
Potomac Electric Power Company	Case No. 7972
Potomac Electric Power Company	Case No. 7874
Washington Gas Light Company	Case No. 7649

Massachusetts

Investigation of Rate Structures to Promote Efficient Deployment of Demand Management	Docket No. 07-50

North Carolina

Generic Electric Load Management	Docket No. M100, Sub 78

New Jersey	
Public Service Electric and Gas	Docket No. GT93060242
Public Service Electric and Gas	Docket No. ER91111698J
Elizabethtown Gas Company	Docket No. 8812-1231
Elizabethtown Gas Company	Docket No. 8612-1374
Public Service Electric and Gas	Docket No. 8512-1163
Jersey Central Power & Light	Docket No. 8511-1116
New Jersey Natural Gas Company	Docket No. 8510-974
South Jersey Gas Company	Docket No. 850-8858
Public Service Electric and Gas	Docket No. 850-2231
New Jersey Natural Gas Company	Docket No. 850-7732
South Jersey Gas Company	Docket No. 843-184, Phase II
Atlantic Electric Company	Docket No. 8310-883, Phase II
New Jersey Natural Gas Company	Docket No. 831-46
Public Service Electric and Gas	Docket No. 837-620
Public Service Electric and Gas	Docket No. 8210-869
New Mexico	
Gas Company of New Mexico	Case No. 2353
Gas Company of New Mexico	Case No. 2340
Gas Company of New Mexico	Case No. 2307
Gas Company of New Mexico	Case No. 2183
Gas Company of New Mexico	Case No. 2147 (Remand)
Gas Company of New Mexico	Case No. 2147
Gas Company of New Mexico	Case No. 2093
New York	
Consolidated Edison Company	Docket No. 94-E-0334
Consolidated Edison Company	Docket No. 91-E-0462
Brooklyn Union Gas Company	Docket No. 90-G-0981
Ohio	
Toledo Edison Company	Case No. 78-628-EL-FAC
Pennsylvania	
PECO Energy Company	Docket No. R-20028394
PG Energy, Inc.	Docket No. R-00061365
Philadelphia Electric Company	Docket No. R-00970258
Mechanicsburg Water Company	Docket No. R-00922502
West Penn Power Company	Docket No. R-00922378
Pennsylvania Electric Company	Docket No. M-920312
North Penn Gas Company	Docket No. R-922276
Metropolitan Edison Company	Docket No. R-922314
York Water Company	Docket No. R-922168
Dauphin Consolidated Water Company	Docket No. R-921000
Pennsylvania Electric Company	Docket No. M-920312

Duquesne Light Company	Docket No. C-913424
Pennsylvania American Water Company	Docket No. R-911909
West Penn Power Company	Docket No. R-901609
Pennsylvania Gas & Water Co. Water Div.	Docket No. R-891209
Pennsylvania Power Company	Docket No. R-881112
Duquesne Light Company	Docket No. R-870651
Pennsylvania Electric Company	Docket No. R-870172
Metropolitan Edison Company	Docket No. R-870171
Western Pennsylvania Water Company	Docket No. R-860397
Duquesne Light Company	Docket No. R-860378
Philadelphia Electric Company	Docket No. R-850290
Pennsylvania Power Company	Docket No. R-850267
Pennsylvania Power & Light Company	Docket No. R-850251
Philadelphia Electric Company	Docket No. R-850152
Western Pennsylvania Water Company	Docket No. R-850096
Pennsylvania Power Company	Docket No. R-842740
Pennsylvania Power & Light Company	Docket No. R-842651
Pennsylvania Electric Company	Docket No. R-832550
Metropolitan Edison Company	Docket No. R-832549
Duquesne Light Company	Docket No. R-842383
UGI Corporation-Gas Utility Division	Docket No. R-832331
Pennsylvania Power & Light Company	Docket No. I-830374
Pennsylvania Electric Company	Docket No. R-822250
Metropolitan Edison Company	Docket No. R-822249
Pennsylvania Power & Light Company	Docket No. R-822169
Pennsylvania Gas & Water Co. - Water Div.	Docket No. R-822102
Columbia Gas Co. of Pennsylvania	Docket No. R-822042
Pennsylvania Gas & Water Co. - Gas Div.	Docket No. R-821961
Philadelphia Electric Company	Docket No. R-811626

Philadelphia, City of

Philadelphia Gas Works	1992 Rate Design Proceeding
Philadelphia Water Dept	1992 Rate Increase Request
Philadelphia Gas Works	1990 Rate Increase Request
Philadelphia Water Dept	1990 Rate Increase Request
Philadelphia Gas Works	1989 Proceeding
Philadelphia Gas Works	1988 Rate Increase Request
Philadelphia Gas Works	1987-88 Operating Budget
Philadelphia Gas Works	1986 Rate Increase Request
Philadelphia Water Dept	1985 Rate Increase Request

Rhode Island – Public Utilities Commission

National Grid – Gas	Docket No. 4647
National Grid – Gas	Docket No. 4634
National Grid – Gas	Docket No. 4576
National Grid – Gas	Docket No. 4573

National Grid – Gas	Docket No. 4523
National Grid – Gas	Docket No. 4520
National Grid – Gas	Docket No. 4514
National Grid – Gas	Docket No. 4436
National Grid – Gas	Docket No. 4431
National Grid – Gas	Docket No. 4346
National Grid – Gas	Docket No. 4339
National Grid – Gas	Docket No. 4333
National Grid – Gas	Docket No. 4323
National Grid – Gas	Docket No. 4283
National Grid – Gas	Docket No. 4269
National Grid – Electric Backup Service	Docket No. 4232
National Grid – Elec & Gas Revenue Decoupling	Docket No. 4206
National Grid – Gas	Docket No. 4199
National Grid – Gas	Docket No. 4196
National Grid – Gas	Docket No. 4097
National Grid – Gas	Docket No. 4077
National Grid – Electric	Docket No. 4065
National Grid – Gas	Docket No. 4038
National Grid – Gas	Docket No. 3982
National Grid – Gas	Docket No. 3977
National Grid – Gas	Docket No. 3961
National Grid – Gas	Docket No. 3943
National Grid – Gas	Docket No. 3868
National Grid – Gas	Docket No. 3859
National Grid – Gas	Docket No. 3789
National Grid – Gas	Docket No. 3766
National Grid – Gas	Docket No. 3760
New England Gas Company	Docket No. 3696
New England Gas Company	Docket No. 3690
Block Island Power Company	Docket No. 3655
New England Gas Company	Docket No. 3548
New England Gas Company	Docket No. 3459
New England Gas Company	Docket No. 3436
New England Gas Company	Docket No. 3401
Providence Gas Company	Docket No. 3295
Narragansett Electric Company	Docket No. 2930
Providence Gas Company	Docket No. 2902
Providence Gas Company	Docket No. 2581
Providence Gas Company	Docket No. 2552
Providence Gas Company	Docket No. 2374
Providence Gas Company	Docket No. 2286
Valley Gas Company	Docket No. 2276
Valley Gas Company	Docket No. 2138, Phase II
Valley Gas Company	Docket No. 2138, Phase I
Providence Gas Company	Docket No. 2082

Providence Gas Company	Docket No. 2076
Providence Gas Company	Docket No. 2001, Phase II
Valley Gas Company	Docket No. 2038
Providence Gas Company	Docket No. 2001
Block Island Power Company	Docket No. 1998
Providence Gas Company	Docket No. 1971
Generic Gas Transportation	Docket No. 1951
Valley Gas Company	Docket No. 1736
Providence Gas Company	Docket No. 1723
Providence Gas Company	Docket No. 1673
Rhode Island – Division of Public Utilities	
National Grid Acquisition of New England Gas Company's Rhode Island Assets	Docket No. D-06-13
Merger of Southern Union, Valley Gas Company And Bristol & Warren Gas Company	Docket No. D-00-02
South Dakota	
Northern States Power Company	Docket No. F-3188
Vermont	
Department of Public Service	Docket No. 5378
Department of Public Service	Docket No. 5307
Virginia	
Virginia Electric Power Company	Docket No. PUE 2015-00027
Virginia Electric Power Company	Docket No. PUE 2011-00027
Washington Gas Light Company	Docket No. PUE 2010-00139
Virginia Electric Power Company	Docket No. PUE 2009-00019
Virginia Electric Power Company	Docket No. PUE 2009-00018
Virginia Electric Power Company	Docket No. PUE 2009-00017
Virginia Electric Power Company	Docket No. PUE 2009-00016
Virginia Electric Power Company	Docket No. PUE 2009-00011
Washington Gas Light Company	Docket No. PUE 2006-00059
Washington Gas Light Company	Docket No. PUE 2005-00010
Washington Gas Light Company	Docket No. PUE 2003-00603
Washington Gas Light Company	Docket No. PUE 2002-00364
Virginia Electric Power Company	Docket No. PUE 000584
Virginia Electric Power Company	Docket No. PUE 980213
Virginia Electric Power Company	Docket No. PUE 980212
Virginia Electric Power Company	Docket No. PUE 960296
Washington Gas Light Company	Docket No. PUE 940031
Virginia Electric Power Company	Docket No. PUE 920041
Virginia Electric Power Company	Docket No. PUE 910047
Northern Virginia Natural Gas	Docket No. PUE 900016
Northern Virginia Natural Gas	Docket No. PUE 880024

Virginia Electric Power Company	Docket No. PUE 830029
Washington Gas Light Company	Docket No. PUE 830008

Virgin Islands

Water and Power Authority – Water Rates	Docket No. 613
Water and Power Authority – Electric Rates	Docket No. 612
Water and Power Authority – Water Rates	Docket No. 576
Water and Power Authority – Electric Rates	Docket No. 575
Water and Power Authority – Electric Rates	Docket No. 533

Wisconsin

Gas Transportation - Generic	Docket No. 05-GI-102

Federal Energy Regulatory Commission

Weaver's Cove Energy, LLC.	Docket No. CP04-36-000
Mill River Pipeline, LLC.	Docket No. CP04-41-000
Columbia Gulf Transmission Co.	Docket No. RP86-167-000
Columbia Gas Transmission Corp.	Docket No. RP86-168-000
Columbia Gulf Transmission Co.	Docket No. TC86-021-000

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