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Sandra Mattavous-Frye, Esq.
People's Counsel

December 14, 2011

VIA ELECTRONIC FILING
Jesse P. Clay, Jr.
Acting Commission Secretary
Public Service Commission
of the District of Columbia
1333 H Street, N.W.
Second Floor West Tower
Washington, D.C. 20005

Re: **Formal Case No. 1087, In the Matter of the Application of Potomac Electric Power Company For Authority To Increase Existing Retail Rates and Charges For Electric Distribution Service**

PUBLIC VERSION

Dear Dr. Clay:

Please find enclosed for filing in the above-referenced proceeding an original and fifteen (15) copies of the "Office of People's Counsel's Direct Testimony and Exhibits (Public Version), Summary of Revenue Requirements Adjustments and Issue Index."

If there are any questions regarding this matter, please contact me at (202) 727-3071.

Sincerely,

Sandra Mattavous-Frye
People's Counsel

Enclosure

cc: Parties of record

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Revenue Requirements of Adjustments
Test Year Ended September 30, 2011
(Thousands of Dollars)

OPC Sch. No.	Description	Rate Base	Net Operating Income	Revenue Requirement Impact
	PEPCO Adjusted Amounts	$ 1,172,025	$ 76,380	
	PEPCO Revenue Requirement Increase at 8.64% Rate of Return			$ 42,523
	OPC Adjustments			
(a)	Reduction in revenue requirement at OPC's rate of return			(26,438)
1	Reduction to AMI Regulatory Asset - Incremental Costs	(2,119)	157	(533)
2	Remove NE Distribution & Substation Plant (RMA 43)	(11,135)	179	(1,699)
3	Reduction to Cash Working Capital	(1,574)		(197)
4	Employee Health & Welfare Expense		246	(420)
5	Storm Damage Costs & Hurricane Irene	(1,207)	497	(999)
6	Remove Non-Recurring Meter Expense, Account 586		184	(314)
7	Remove Accounts Receivable Write-Off		26	(44)
8	Remove Post-Test Year Flotation Costs	(355)	237	(449)
9/KM	Incremental Customer Care Exp - Energy Advisors & Engineers		55	(94)
10/KM	Reduction to Meter Blanket Capital Budget	(713)	29	(139)
11/KM	Reduction to Feeder Undergrounding Capital Budget	(2,851)	42	(428)
NB	Reversal of Medicare OPEB Tax Subsidy Adjustment (RMA 9)	(209)	85	(171)
NB	Remove Severance Regulatory Asset and Amortization (RMA 28)	(2,343)	970	(1,951)
12	Interest Synchronization Adjustment		(1,863)	3,184
13	Reduction to Forecast Net Plant Additions	(12,580)	183	(1,886)
14/RB	Reduction to AMI Depreciation to Reflect Current Rates	(629)	630	(1,155)
	Total OPC Adjustments	(35,715)	1,657	(33,737)
	Revenue Requirement at OPC's Recommended ROR	$ 1,136,310	$ 78,037	$ 8,786

Source/Notes:
(a) See Exhibit OPC(B)-3, Summary Schedules, Page 3 of 4.
KM - Adjustment sponsored by OPC witness Kevin Mara
RB - Adjustment sponsored by OPC witness Ron Binz
NB - Adjustment sponsored by OPC witness Nancy Bright

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 Existing Retail Rates and Charges for Electric Distribution Service	))))	**Formal Case No. 1087**

The Office of the People's Counsel of the District of Columbia hereby submits the following Issue Index to its Direct Testimony filed on Wednesday, December 14, 2011.

Issue	Question	OPC Witness & Exhibit
1	Is Pepco's proposed $42,101,000 increase in base distribution rates just and reasonable?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-1, (B)-2, (B)-3
2	Is Pepco's test year ending September 30, 2011, reasonable?	Donna Ramas, Exhibit OPC (B)
2a	Are the proposed adjustments to the test year data for known and measureable changes reasonable?	Donna Ramas, Exhibit OPC (B)
2b	Are Pepco's budgeted or forecasted amounts for the forecasted portion of the proposed test year (April 2011 through September 2011) reasonably forecasted and based on reasonable projections?	Donna Ramas, Exhibit OPC (B), Exhibit No. OPC (B)-7
3	Is Pepco's proposed rate base just and reasonable?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-2, (B)-3, (B)-4
3a	Are the projected plant additions and retirements for the forecasted portion of the proposed test year, i.e., April 2011 through September 2011, reasonably projected?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-4, (B)-5, (B)-8, (B)-9, (B)-10, (B)-11, (B)-12, (B)-13
3b	Are Pepco's proposed adjustments to the average test year rate base just and reasonable?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-2, (B)-3, (B)-4, (B)-14
3c	Is Pepco's proposed cash working capital allowance reasonable?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-4, (B)-15

4	Are Pepco's test year sales and revenues just and reasonable?	Donna Ramas, Exhibit OPC (B)
4a	Has Pepco properly weather-normalized its sales and revenue?	Donna Ramas, Exhibit OPC (B)
5	Are Pepco's operating expenses just and reasonable?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-2, (B)-3, (B)-4, (B)-16, (B)-17, (B)-18, (B)-19, (B)-20, (B)-21, (B)-22, (B)-23, (B)-24
6	Are Pepco's depreciation adjustments reasonable?	Donna Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-2, (B)-3, (B)-4
7	Are Pepco's requested cost of capital and capital structure reasonable?	J. Randall Woolridge, OPC (C), Exhibit Nos. OPC (C)-1 through (C)-16
7a	What cost of common equity should Pepco be authorized to earn?	J. Randall Woolridge, OPC (C), Exhibit Nos. OPC (C)-1 through (C)-16
7b	Has Pepco properly determined its cost of debt?	J. Randall Woolridge, OPC (C), Exhibit Nos. OPC (C)-1 through (C)-16
7c	Is the capital structure that Pepco uses to develop its overall cost of capital reasonable and appropriate?	J. Randall Woolridge, OPC (C), Exhibit Nos. OPC (C)-1 through (C)-16
7d	Should Pepco's authorized Return on Equity ("ROE") be adjusted for a Bill Stabilization Adjustment ("BSA") and, if so, by how many basis points?	J. Randall Woolridge, OPC (C), Exhibit Nos. OPC (C)-1 through (C)-16
7e	Should Pepco's authorized ROE be adjusted for a RIM or alternate cost recovery mechanism and, if so, by how many basis points?	J. Randall Woolridge, OPC (C), Exhibit Nos. OPC (C)-1 through (C)-16
8	Are the PHI Service Company costs charged by Pepco reasonable?	Nancy B. Bright, Exhibit OPC (D), Exhibit Nos. OPC (D)-1 through (D)-10
9	Are Pepco's costs for the deployment of Advanced Metering Infrastructure ("AMI") reasonable?	Kevin J. Mara, Exhibit OPC (E), Exhibit Nos. (E)-25 through (E)-30, (E)-34, and (E)-35, Ramas, Exhibit OPC (B), Exhibit Nos. OPC (B)-4, (B)-25
9a	Are cost savings attributable to AMI implementation appropriately reflected in Pepco's operating expenses (e.g., reduced meter reading expense, pension costs, etc.)?	Kevin J. Mara, Exhibit OPC (E)
9b	Is the accounting treatment of old meters reasonable?	Donna Ramas, Exhibit OPC (B)
9c	Is the proposed length of depreciation reasonable for new meters and other associated AMI costs?	Donna Ramas, Exhibit OPC (B), Exhibit No. OPC (B)-4
10	Are Pepco's customer care initiative and the Company's proposal to add energy advisors and energy engineers reasonable?	Kevin J. Mara, Exhibit OPC (E), Exhibit Nos. (E)-31, (E)-32, and (E)-33

11	Do Pepco's costs for reliability improvement projects in the test year represent reasonable and prudent expenditures?	Kevin J. Mara, Exhibit OPC (E), Exhibit Nos. (E)-5 through (E)-16
12	Does the quality and reliability of Pepco's electric distribution service in the District of Columbia warrant an adjustment to the base rates proposed by Pepco in this case? If so, what is the basis for the adjustment and what should the adjustment be?	Kevin J. Mara, Exhibit OPC (E), Exhibit Nos. (E)-17 and (E)-18, Ronald J. Binz, Exhibit OPC (A)
13	Is Pepco's proposed Jurisdictional Cost Allocation Study for distribution service reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-1 through (F)-4
14	Is Pepco's proposed distribution of its revenue requirement reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-2, (F)-3, (F)-5 through (F)-11
14a	Is Pepco's proposed Class Cost Allocation Study reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-2, (F)-3, (F)-5 through (F)-11
15	Is Pepco's rate design just and reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15a	Is Pepco's proposed increase in monthly customer charges just and reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15b	Is Pepco's proposed change in rate design to the rate schedule for Street Lighting ("SL") reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15c	Is Pepco's proposed change in rate design to the rate schedule for Traffic Signals ("TS") reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15d	Is Pepco's proposed change in rate design for the rate schedule for Rapid Transit ("RT") reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15e	Are Pepco's proposed residential rate designs reasonable for all rate schedules?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15f	Are Pepco's proposed other rate designs reasonable for all rate schedules?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
15g	Should RAD distribution rates be maintained at the same level or should they be altered as a result of changing revenue requirements from this rate case?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
16	Are Pepco's proposed changes in tariff language reasonable?	Karl R. Pavlovic, Exhibit OPC (F), Exhibit Nos. OPC (F)-12 through (F)-17
17	Does Pepco's presentation of its revenue requirement properly reflect the impacts of current District of Columbia and federal tax regulations?	Nancy B. Bright, Exhibit OPC (D), Exhibit Nos. OPC (D)-11 and (D)-12

18	Is Pepco's proposed Reliability Investment Recovery Mechanism (RIM) just and reasonable?	David E. Dismukes, OPC Exhibit (G), Exhibit Nos. OPC (G)-1 through (G)-36
18a	Does Pepco's multi-year (2011-2015) construction budget in its RIM proposal provide a level of investment sufficient to fund projects that will result in significant reliability improvements?	Kevin J. Mara, Exhibit OPC (E), Exhibit Nos. (E)-13, (E)-19, (E)-20, (E)-21, and (E)-22
18b	Should conditions be attached to a funding mechanism for reliability improvements such as RIM? If so, what conditions are appropriate?	David E. Dismukes, OPC Exhibit (G)
18c	Should Pepco's recovery of reliability related costs through a funding mechanism be tied to reliability performance targets?	Kevin J. Mara, Exhibit OPC (E), Exhibit No. (E)-23 David E. Dismukes, OPC Exhibit (G), Exhibit Nos. OPC (G)-2 and OPC (G)-33
18d	Which projects (or types of projects) financed by any selected cost recovery mechanism can best satisfy the two reliability objectives specified in Formal Case Nos. 766,982, and 991, Order No. 16347 at paragraph 2 (May 5, 2011)?	Kevin J. Mara, Exhibit OPC (E), Exhibit No. (E)-24

CERTIFICATE OF SERVICE

Formal Case No. 1087, In the Matter of the Application of Potomac Electric Power Company For Authority To Increase Existing Retail Rates and Charges For Electric Distribution Service

I hereby certify that on this 14th day of December, 2011, a copy of the "Office of People's Counsel's Direct Testimony and Exhibits (Public Version)" was served on the following parties of record by hand delivery, first class mail, postage prepaid, or electronic mail:

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Assistant People's Counsel

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of the	)	**Formal Case No. 1087**
Potomac Electric Power Company	)	
For Authority to Increase	)	
Existing Retail Rates and Charges	)	
For Electric Distribution Service	)	

DIRECT TESTIMONY AND EXHIBITS OF
THE OFFICE OF THE PEOPLE'S COUNSEL
(PUBLIC VERSION)

VOLUME 1 OF 4

RONALD J. BINZ	**EXHIBIT OPC (A)**
DONNA RAMAS	**EXHIBIT OPC (B)**

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OF THE DISTRICT OF COLUMBIA
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DECEMBER 14, 2011

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	**Formal Case No. 1087**
Power Company for Authority to Increase Existing	)	
Retail Rates and Charges for	)	
Electric Distribution Service	)	

DIRECT TESTIMONY AND EXHIBITS
OF
RONALD J. BINZ
EXHIBIT OPC (A)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

DECEMBER 14, 2011

Exhibit OPC (A)

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	Formal Case No. 1087
Power Company for Authority to Increase Existing	)	
Retail Rates and Charges for	)	
Electric Distribution Service	)	

DIRECT TESTIMONY OF RONALD J. BINZ

I. INTRODUCTION

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

A. My name is Ronald J. Binz. My business address is 333 Eudora Street, Denver, Colorado 80220-5721. I am a Principal with Public Policy Consulting, a firm specializing in energy and telecommunications regulatory matters. I provide consulting services to a variety of public-sector and private-sector clients in the energy and telecommunications industries, primarily in the regulatory arena. My consulting practice dates to 1979, except for the years 1984-1995 when I served as Colorado Consumer Counsel and 2007-2011 when I was the Chairman of the Colorado Public Utilities Commission.

Q. PLEASE DESCRIBE YOUR WORK AS COLORADO CONSUMER COUNSEL.

A. As consumer counsel, I represented the interests of residential, small business and agricultural consumers of telecommunications and energy before the Colorado Public Utilities Commission, the Federal Communications Commission (FCC), the Federal Energy Regulatory Commission (FERC), the courts and legislative bodies.

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Q. PLEASE DESCRIBE YOUR WORK AS CHAIRMAN OF THE COLORADO PUBLIC UTILITIES COMMISSION.

A. I was appointed Chairman of the Colorado Public Utilities Commission in January 2007 by Governor Bill Ritter, Jr. Even prior to his election, Governor Ritter had committed to developing a "new energy economy" in Colorado. During his single four-year term, he signed seventy-nine pieces of legislation affecting energy in Colorado, many dealing with regulated public utilities. In addition to the usual set of duties of a Commissioner, I led the implementation of the policies championed by the Governor and General Assembly. These included implementing a 30% renewable energy standard, an energy efficiency standard, extensive resource planning, residential rate design, and compliance with EPA Clean Air Act regulations. We grappled with the critical issues of the smart grid, including meter deployment, rate design and customer privacy.

As Commissioner, I was active within NARUC, acting as chair of the Task Force on Climate Policy and serving on the Energy Resources and Environment Committee. I am a frequent speaker and presenter at industry, regulatory and legislative conferences and symposia. I am a member of the Harvard Electricity Policy Group and previously served on two advisory commissions to the Federal Communications Commission. I have also testified fifteen times before Congressional committees on energy and telecommunications matters.

Q. PLEASE DESCRIBE YOUR CURRENT CONSULTING PRACTICE.

A. Public Policy Consulting offers assistance to regulators, consumer and industry players on the current issues in energy regulation. My clients include the Center for the New Energy Economy at Colorado State University, the Lawrence Berkeley National Laboratory, Ceres, Tendril Networks, Inc., American Efficient, the Northern Laramie Range Alliance, an association of ranchers in Wyoming, and a foundation-supported research and action project about the changing business model for utilities and needed changes to their regulation.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a B.A. in Philosophy from St. Louis University in 1971. I received M.A. in Mathematics from the University of Colorado in 1977. I entered the Masters Program in Economics in 1980 and completed 27 hours of graduate work. My *curriculum vitae* is attached as Appendix A to this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Office of the People's Counsel of the District of Columbia ("OPC" or "Office").

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

II. <u>SCOPE OF TESTIMONY</u>

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS CASE?

A. I was asked by the Office of People's Counsel to serve as the introductory witness for the Office, providing an overview of OPC's position in this case; to respond to the testimony of Pepco witness Kamerick; and to describe the testimony of the other OPC witnesses.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. I have included one Appendix and 2 Exhibits:

Appendix A: Resume of Ronald J. Binz

Exhibit OPC (A)-1: Colorado Public Utilities Commission Order Addressing Phase I and ECA Issues

Exhibit OPC (A)-2: Colorado Public Utilities Commission Order on Exceptions

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I discuss how Pepco's actions impact the decisions to be made in this case. Second, I outline the policy issues I am sponsoring on behalf of the Office. Next, I respond to some of the issues raised by Pepco Witness Kamerick in his testimony. I summarize the Company's Reliability Investment Recovery Mechanism (RIM) proposal and identify the regulatory principles and goals that the Commission should use in evaluating this request. Then, I introduce the other OPC witnesses and describe their testimony in this case. Finally, I summarize my testimony and recommendations to the Commission.

III. <u>OPC POLICY POSITIONS</u>

Q. AS OPC'S POLICY WITNESS, DO YOU THINK THERE ARE ASPECTS OF THIS CASE THAT IMPACT THE IMPORTANT DECISIONS THAT NEED TO BE MADE IN THIS CASE?

A. Yes. First, overall I found Pepco's case lacking in details concerning the Company's request for cost recovery for reliability projects. Given the Company's poor track record on reliability, Pepco should have provided the Commission with as much detail as possible to address the reliability issues that have plagued District of Columbia consumers for the past ten years. Instead, the Company presented a skeletal case that outlined plans and ideas to address this serious issue when details were needed.

Second, I am concerned by the slow process in which Pepco provided certain information in the discovery phase of this case. This is an important case not only for Pepco, but for all stakeholders in the District of Columbia. The Commission must make some important decisions about service reliability, smart grid cost recovery and how costs for reliability projects will be recovered. Pepco's actions makes it much harder to develop a comprehensive record in the case and limits parties' ability to present fully developed testimony to aid the Commission in deciding these important issues.

Q. WITH REGARDS TO DISCOVERY, HAS OPC RECEIVED ALL OUTSTANDING DISCOVERY?

A. Yes, with the exception of one data response which OPC Witness Bright is still awaiting. Of the responses received, a number of responses were not received until late the week of December 5th. As such, OPC has not had the opportunity to thoroughly review the material. OPC, therefore, reserves the right to supplement its Direct Testimony, if necessary, after review of the late-filed responses.

Q. ARE THERE ANY POLICY POSITIONS THAT YOU ARE SPONSORING IN THIS CASE?

A. Yes. There are two policy positions I am adopting on behalf of the Office. The first concerns OPC's answer to Issue 12 and the second relates to the Office's position on the depreciation of the AMI meters.

Q. PLEASE EXPLAIN OPC'S POLICY POSITION IN RESPONSE TO ISSUE 12.

A. Issue 12 asks "Does the quality and reliability of Pepco's electric distribution service in the District of Columbia warrant an adjustment to the base rates proposed by Pepco in this case? If so, what is the basis for the adjustment and what should the adjustment be?"

OPC believes that the quality and reliability of Pepco's distribution service must be improved and supports a rate adjustment that conveys the Commission's seriousness about this issue to Pepco ***and to consumers*** in the District. OPC offers the Commission three options for such an adjustment to base rates:

<u>Option 1:</u> The Commission could adopt the position of OPC Witness Woolridge as outlined in his testimony. He recommends an ROE of 9.0% for all of the economic reasons outlined in his testimony. If however, the Commission grants a ROE higher than 9.0%, he proposes the Commission approve a 25 basis point reduction to reflect the quality and reliability issues discussed in OPC witness Mara's testimony; or

<u>Option 2:</u> If the Commission approves any increase for reliability projects, it should only allow 50% of the associated revenue requirement to be included in rates at this time, with the remaining 50% carried as a regulatory asset and included in rates only after Pepco complies with the Commission's new EQSS rules for a full year; or

<u>Option 3:</u> The Commission should require Pepco to credit consumers with $2 million on a one-time basis to compensate for the poor reliability over the past several years.

Q. WHAT IS THE OFFICE'S POLICY POSITION CONCERNING THE ADJUSTMENT TO THE DEPRECIATION OF THE AMI METERS?

A. It is OPC's position that there should not be an adjustment to the depreciation rate for the new AMI meters without a new depreciation study. OPC Witness Ramas has made the adjustment in her testimony to reflect this position.

IV. OPC'S CASE OVERVIEW

Q. WHY IS THIS CASE IMPORTANT TO THE OFFICE OF PEOPLE'S COUNSEL?

A. Pepco filed a case seeking to increase electric rates by $42.5 million, which represents a 34% increase in the residential distribution rate, and to institute two new major regulatory policies. These are tough economic times for consumers and OPC wants to ensure that any increase in revenues is fully justified and that consumers receive benefits from these investments. The Commission wisely set aside one of the new regulatory issues – the future test year – until an appropriate proceeding. OPC is concerned that the requested revenue increase is not justified and that the remaining major policy change, the Reliability Investment Recovery Mechanism, is bad regulatory policy and flawed as a cost adjustment mechanism.

OPC also continues to be concerned about the reliability of Pepco's service in the District. In its RIM proposal, it appears to OPC that Pepco is seeking a much less rigorous and more generous regulatory treatment before the Company has shown the ability to provide reliable and reasonably priced service – its essential duty as a public utility. OPC has consistently urged this Commission to focus its attention on Pepco's reliability problems and commends the Commission for making reliability a central issue of this rate case. OPC believes this case provides the Commission with an excellent additional opportunity to show Pepco that it means what it says about quality of service.

In brief, OPC's interest in this case is organized around four interrelated topic areas:

1. Reliability and quality of service
2. Financial issues, including the revenue requirement and rate design

3. Advanced Metering Infrastructure ("AMI")-related issues of cost/benefit and the deployment schedule

4. New regulatory proposals, including the RIM

OPC develops its position on each of these core issues through the testimony of seven expert witnesses. In doing so, the Office responds to each of the eighteen questions posed by the Commission at the outset of this proceeding in Order No. 16570.

Q. BEFORE TURNING TO OPC'S SPECIFIC FINDINGS AND RECOMMENDATIONS TO THE COMMISSION, PLEASE COMMENT ON EACH OF THE FOUR TOPIC AREAS YOU HAVE IDENTIFIED.

A. **Reliability and Quality of Service.** Regulation exists because utility companies like Pepco do not face competition sufficient to force them to provide quality service and constrain prices to fair levels. Simply put, regulation steps in when competition fails to do the job. Before getting to the question of what constitutes fair prices, the Commission must consider that Pepco is failing to meet its quality of service obligations.

Electric reliability and customer service in the District of Columbia are not what they should be. Consider what would happen to a firm operating in a competitive market with Pepco's service quality record. The firm would lose customers to other suppliers with better service records. Unless such a competing firm fixed its service and reliability problems, it would likely fail.

Competitive suppliers of electric distribution service do not exist and likely will never exist because of the economies of scale and scope of the industry. In this situation, quality of service becomes an issue with which regulators must be vitally concerned.

In general, there are only a few ways that regulators can act that induces specific actions by a regulated utility. In his 1961 treatise, Professor James C. Bonbright notes:

> ...the standards of a commission-fixed "fair rate of return" are themselves somewhat flexible, and some commissions, in setting these rates, try to make some allowance for supposed relative efficiency or inefficiency of operation and of financial planning.[1]

Although he was referring specifically to overall efficiency of a firm, the very same point applies to efficiency as it relates to distribution maintenance and investment. In this case OPC believes the Commission, when crafting its decision, should give careful consideration to the fact that Pepco has been delivering inferior service for the past several years. This is the logic behind OPC's Option 1 for a base rate adjustment in response to Issue 12.

Financial Issues including Revenue Requirement and Rate Design. Next to reliability, or perhaps tied with reliability, the public cares about the price of electricity. In this case Pepco is asking for a 34% increase in the residential distribution rate only eighteen months after new rates became effective following the last case. OPC has carefully scrutinized the cost of equity for Pepco, examined whether the test period is representative, and whether Pepco correctly allocates costs between its jurisdictions. The Office offers the testimony of six witnesses on these points.

As discussed below, OPC's cost of service, cost of capital and other expert witnesses concluded that Pepco has overstated its cost of equity capital, has overstated some of its expenses and has failed to make some necessary adjustments to the test period. Taken

[1] Bonbright, James C. 1961. Principles of Public Utility Rates. New York: Columbia University Press, p. 53.

altogether, OPC believes Pepco's revenue shortfall is no larger than $8.8 million, considerably less than the $42.5 million the Company is seeking.

Importantly, OPC's analysis allows the Company to recover the cost of AMI investments with conditions.

AMI-Related Issues of Cost/Benefit and the Deployment Schedule. As the Commission is aware, OPC supports cost-effective investment in smart grid technologies. The Office understands the promise of engaging customers more fully by enabling them to better understand their usage patterns and helping customers have more control over their electric bills.

That said, OPC wants to be sure that any rate increases related to smart grid investment are justified by short-term and long-term benefits. Moreover, OPC is reluctant to grant cost recovery to Pepco simply on the promise of smart grid investment being made. In its analysis in this case, OPC employs a distribution system expert to examine Pepco's plans for smart grid investment. He raises concerns about whether the Company is likely to succeed in the plan it has announced on the anticipated timeframe.

As in all other areas of ratemaking, the Commission and OPC should watch carefully that the Company maintains its focus on this grid modernization project, that the benefits materialize sufficiently to justify the costs, and that the timing of revenue increases matches the benefits. In this case, OPC has crafted an approach for the Commission's consideration that allows for the recovery of AMI investment to begin, subject to Pepco performing satisfactorily.

As a commissioner of the Colorado Public Utilities Commission ("Colorado Commission"), I was faced with a very similar situation: a utility was seeking in a rate case to add $45 million in smart grid investment to rate base. The benefits of the project were not fully described and there was debate about whether the utility was managing the project prudently. In a general rate case, the Colorado Commission permitted rates to increase reflecting the addition of the investment, subject to a more thorough future review of the project.

Subsequently, the Colorado Commission determined that the benefits of the project did not warrant the level of investment. The Colorado Commission removed $16 million in investment and lowered rates by the corresponding revenue requirement. The Colorado Commission also announced that the utility could return with a request that the full investment be included in rates if it made certain showings.

I have included in my testimony an excerpt from the Orders in which the Colorado Commission allowed conditional recovery of the smart grid investments (Exhibit OPC (A)-1) and subsequently reduced the amount permitted in rates (Exhibit OPC (A)-2) . We believe that our action provided a balanced approach, signaling to the utility that full cost recovery required a showing of customer benefits and adequate management attention to the issue.

OPC's proposal for AMI cost recovery offers this Commission the same opportunity to carefully monitor the progress of Pepco's AMI deployment and ensure that consumers do not bear the full brunt of the costs of an AMI system that does not deliver its stated benefits.

In my view, OPC's proposal on AMI cost recovery is consistent with the resolution adopted by the National Association of Regulatory Commissioners in July 2011 that encourages state commissions to identify the risks and rewards of smart grid investment projects and allocate those risks and rewards appropriately to utility shareholders and consumers when evaluating smart grid investments and to align payments by consumers with benefits to consumers to the extent reasonably possible when making cost recovery decisions.

New Regulatory Proposals, Including the RIM. In its filing in this case, Pepco repeatedly stated its goal to reduce or eliminate "regulatory lag." The Company proposed two major changes to the way cost of service regulation is practiced in the District of Columbia – using a future test period and creating the RIM, an investment-tracking rider. As I will discuss later in this testimony, regulatory lag is actually an important component of cost of service regulation, not the unalloyed negative portrayed by Pepco and many other utilities. Moreover, eliminating regulatory lag completely re-writes the established equities between utilities and their customers. This is not merely a modification to regulation; it is shifting risk and shifting equities all to the detriment of consumers.

Pepco has also conflated "regulatory lag" with the use of an historical test period. This is incorrect in principle and in practice: there is nothing that intrinsically connects the selection of test year to regulatory lag. The Commission will be well-served to examine the test year issue on its own merits, and not as part of a utility's campaign to eliminate "regulatory lag." For that reason, OPC thinks that the Commission wisely excluded the issue of the future test period from the instant docket.

V. <u>SUMMARY OF OPC'S ANALYSIS</u>

Q. PLEASE SUMMARIZE OPC'S ANALYSIS AND POSITION IN THIS CASE.

A. After carefully examining the Company's filing, OPC has drawn the following conclusions about Pepco's request for higher rates:

- The appropriate cost of equity for Pepco is 9.0%. Capital costs have fallen in recent years, long term interest rates are much lower, and Pepco cannot justify maintaining its currently-authorized cost of capital. Against market indicators, Pepco has actually proposed to increase its return on equity (ROE).

- Pepco's estimate of test year rate base and expenses requires numerous adjustments. Most notably, OPC identifies the following major adjustments:

    - Reducing rate base by $35.7million

    - Decreasing amortization expense by $3.2 million

    - Decreasing operation and maintenance expense by $1.0 million.

- Combining the correct cost of equity capital with the correctly stated test year expenses and revenues, OPC has concluded that the Commission should not award Pepco an increase larger than $8.786 million. The Commission should reject the Company's RIM proposal. OPC supports the Company making prudent, additional investment to improve reliability — a core responsibility of the utility. Precisely because reliability and adequate service are core responsibilities, these investments warrant careful Commission scrutiny, not special regulatory treatment that would allow such investment in rate base before Commission review. The Company has not shown that the RIM is necessary or that it cannot make the needed reliability-related investments under traditional ratemaking methods.

- If the Commission decides to approve a RIM for Pepco, the Office recommends that the Company be required to file a revised RIM proposal with numerous changes to insert consumer protections, limit the rate impact of the RIM, and generally add needed balance into the proposal. Although he recommends against adopting the RIM proposal, Dr. Dismukes describes in detail the changes necessary if the Commission adopts a RIM proposal despite its major theoretic and practical failings. OPC Witness Mara recommends that, if, notwithstanding its numerous flaws, the Commission adopts the RIM, projects to be included in the RIM be strictly limited to reliability projects only.

- As it concerns reliability investments, the Commission should require Pepco to provide detailed plans to allow the Commission to determine if the projects are reasonable. Specifically, the detail should include the costs, reasons for the projects, alternative plans, and expectations of reliability improvements.

- As it concerns AMI cost recovery, the Commission should make it clear that merely deploying the AMI system is not enough. The Commission should allow cost recovery for AMI investments at this time, but base its approval upon strict conditions. In addition, the Commission should allow cost recovery for Energy Advisors, but not for Energy Engineers at this time.

- Finally, the Commission should continue to insist that Pepco improve its reliability. This is not the time to reward Pepco for the *status quo*. For this reason, OPC offers the Commission three options to adjust base rates to respond to the Company's poor performance on reliability.

VI. DISCUSSION

A. REGULATORY LAG AND THE RIM PROPOSAL.

Q. WHAT REGULATORY PRINCIPLES ARE AT ISSUE IN THIS CASE?

A. This case is about some fundamental issues in utility regulation. Pepco has served up a request designed to increase its profitability notwithstanding the fact that the Company is among the 25% worst performers on common measures of reliability. The Company is seeking special regulatory treatment for infrastructure investment needed to restore adequate reliability, a basic responsibility of any utility. With all due respect, OPC suggests that the Public Service Commission needs to go back to basics in deciding this case and not be swayed by the rhetoric that regulation is unfair because it "lags."

Regulation must do much more than simply ensure that regulated utilities are financially healthy and that rates are fair. Regulation should try to make regulated utilities more efficient — in much the same way that companies in a competitive market feel pressure to be efficient. Regulation must also try to ensure that consumers get safe and adequate service. Without competitive pressure to weed out companies with poor service or spotty reliability, it is up to the Commission to apply that pressure.

In sum, OPC believes that the Commission should carefully examine the question of exactly what level of revenues for Pepco can be justified. If the Commission errs, it should be in the direction of consumers because of the generally poor reliability performance Pepco continues to display and in light of the Commission's statutory mandate to consider the economy of the District of Columbia.

Q. DO YOU AGREE WITH MR. KAMERICK'S ANALYSIS OF THE TEST YEAR ISSUE?

A. No, I do not. Because the Commission has removed the future test year issue from this case, I will not dwell on the subject except to comment on a quotation from Mr. Kamerick's testimony. At page 9-10 of his Direct Testimony, he states:

> As the Commission is aware, the rate setting process is forward-looking. Adequate rates for the future cannot be based solely upon an historical test period, particularly an historical test period that uses an average rate base.

I agree that regulation is forward looking. But I disagree with Mr. Kamerick's characterization of the function and effect of a test period. Mr. Kamerick should know that the careful regulator uses the results of a test year (whether historical, current or future) to estimate the impact that new rates will have on the Company's earnings when the rates are put into effect. Pro-forma adjustments are used to correct any anomalous results in the test period. Revenues and expenses are matched so that they become representative of their relationship in a future period. Bottom line, there is nothing intrinsically wrong with using an historical test.

Q. WHY SHOULD THIS BASIC NOTION BE REITERATED?

A. Pepco, along with many other utilities have been trying for years to "improve" cost of service regulation by adding numerous "cost recovery" mechanisms. This effort is often justified as mitigating "regulatory lag."

As Chairman of the Colorado Commission, I dealt with persistent pressure from utilities to institute "cost-recovery riders." In general, I do not support the establishment of such cost adjustment mechanisms for regulated companies for two basic reasons.

First, cost adjustment mechanisms tend to dull the incentives for efficiency that cost of service regulation provides to utilities. Although there may be some good reasons to adopt such mechanisms in specific situations, those justifications usually relate to regulatory efficiency and the financial health of the regulated companies. In my opinion, cost adjustment mechanisms are often adopted by regulators not because of incentives they provide, but in spite of them.

My second concern with cost adjustment mechanisms is that they change the balance of equities embodied in cost of service regulation. Cost adjustment mechanisms are usually applied only to costs that trend upward over time. It would be a rare utility that would propose a cost mechanism to track, for example, per unit labor costs over time. By removing an upward-trending cost and tracking it with a cost adjustment mechanism, the balance of fairness in ratemaking is changed.

Q. PLEASE COMMENT ON PEPCO'S REQUEST TO INSTITUTE AN "INVESTMENT RECOVERY" MECHANISM CALLED THE RELIABILITY INVESTMENT RECOVERY MECHANISM OR RIM.

A. Cost of service regulation is often criticized as being "cost-plus." This is technically and legally incorrect. It is a misnomer to describe rate-setting as an exercise in "cost recovery" in the sense that an insurance company reimburses a homeowner for a loss, or a sales person files to "recover" expenses for travel. Once rates are set, a utility typically is responsible to deliver service of an acceptable quality to customers at prescribed rates even as their costs move up or down. If a utility's rates fall too far short of their costs, its option is to file for a rate increase. But an increase applies to the future—not to past activities.

As an illustration of the shift in mindset that utilities invite public service commissions to make, consider the following quote from Mr. Kamerick's testimony:

> Pepco has made and will continue to make significant investments in the repair and replacement of the Company's aging reliability-related infrastructure. While necessary and beneficial for existing customers, the investments do not relate to the connection of new customers, and consequently do not produce sufficient revenue to recover costs associated with the investment. The creation of a RIM will allow the Company to <u>efficiently recover costs</u> that are mandated by Pepco's obligation to provide safe, reliable and adequate service to its customers without the need to file frequent rate cases. Kamerick Direct, p 13. (Emphasis added)

In my mind, this quote raises the questions "How could reliability have been adequate in the past when there was no RIM mechanism?" and "How do other utilities provide reliable service when they don't have a RIM?"

The answer to these questions is, of course, that normal regulation is adequate for the task and a special "investment recovery mechanism" is not needed to accomplish the restoration of reliability in the District of Columbia. OPC Witness Dismukes provides a complete discussion of the RIM proposal and I will not comment on the details of the proposal other than to say that, as a former regulator, I recommend that the Commission carefully examine the precedent and incentives it would provide by approving the RIM proposal.

Cost of service regulation can provide a meaningful incentive for utilities to control costs, especially in the short run between rate cases. It is important that the Commission not reduce or defeat this incentive by approving inappropriate cost "recovery" mechanisms. If a cost adjustment mechanism is used, it should be designed to retain as many of the desirable incentives of cost of service regulation as possible. I fully endorse the testimony of Dr. Dismukes on these points.

B. INTRODUCTION OF OPC WITNESSES.

Q. PLEASE INTRODUCE THE WITNESSES FOR OPC.

A. OPC offers the testimony of six witnesses in addition to myself. I will introduce each witness and summarize the major points of the testimony.

Ms. Donna Ramas is the main OPC witness concerning the Company's revenue requirements. In her testimony, Ms. Ramas responds to Designated Issues 1-6, 9(b) and 9(c) of the Commission's order setting the case. She adopts the same test period employed by Pepco, but disagrees with several estimates made by the Company in assessing its revenue requirements. Her study incorporates inputs from other OPC witnesses, including Dr. Woolridge, Ms. Bright, and Mr. Mara. In all, Ms. Ramas sponsors approximately 10 adjustments to Pepco's estimate of rate base, revenue and operating expenses. The largest adjustments to the revenue requirements case presented by Pepco are:

- Using a cost of capital of 7.32% as recommended by Dr. Woolridge, resulting in a decrease in Pepco's revenue requirement of about $26 million.
- Reducing rate base by $35.7 million
- Decreasing amortization expense by $3.2 million
- Decreasing operation and maintenance expense by $1.0 million.
- Increasing federal income tax by $3.3 million

Dr. J. Randall Woolridge presents testimony concerning Pepco's cost of common equity, cost of debt and capital structure. He conducted a Discounted Cash Flow (DCF) study as well as a Capital Asset Pricing Model (CAPM) study of the cost of common equity. Dr.

Woolridge finds that the combined range of the two analyses indicates a cost for equity capital in the range of 7.6% to 9.4%. Relying more heavily on the DCF analysis, Dr. Woolridge concludes that a rate of return on equity of 9.0% is appropriate, including the BSA adjustment adopted previously by the Commission. Dr. Woolridge disagrees with Pepco's choice of capital structure. Using the capital structure of the holding company, he concludes that the appropriate capital structure should include short term debt and a revised debt-equity balance. Combining the cost of common equity and the corrected capital structure, Dr. Woolridge's analysis yields a weighted average cost of capital of 7.32%, lowering Pepco's calculated revenue requirement by about $26 million. Finally, Dr. Woolridge explains the shortcomings in the analysis of Pepco Witness Hevert. In sum, Dr. Woolridge addresses Designated Issues 7(a) – 7(e) of the Commission's order.

Ms. Nancy Bright examined two of the issues designated by the Commission: Issue No. 8 - whether costs from PHI Holdings are reasonable; and Issue No. 17 - whether Pepco has correctly accounted for federal and District of Columbia taxes. She concludes that District ratepayers should not be required to pay the severance charges incurred by Pepco Holdings, Inc. (PHI) in connection with PHI's recently completed sale of Conectiv Energy. Ms. Bright also recommends that the Commission expand its ongoing audit of Pepco management to include a review of whether Pepco is in compliance with the Commission's new Code of Conduct and modify its management audit filing obligation to ensure that the management audit process can review charges to Pepco from the PHI Service Company. Ms. Bright also concludes that the Commission should reject Pepco's request to recover deferred taxes associated with the Medicare Part D subsidy over three years.

Mr. Kevin Mara thoroughly examines the reliability investments made by Pepco in the District and assesses the Company's program for deploying Advanced Metering Infrastructure. In his testimony, Mr. Mara responds to Designated Issues 9, 9(a), 10, 11, 12, 18, 18(a),(c) and (d) of the Commission's order setting the case. Witness Mara concludes that Pepco has not provided sufficient evidence to determine if the reliability improvement projects are reasonable. He also disagrees with the use of the RIM as a funding mechanism, but recommends that, if it is used, it only be used for projects designed for reliability. Although he does not find that the costs for AMI deployment were imprudently incurred, he states his serious concerns about whether the project will be completed by the second quarter of 2012 and whether the AMI system will deliver its stated benefits. In response to those concerns, he offers a proposal to allow for a future reduction in rate base if the AMI system is not fully functioning and delivering sufficient benefits. Last, regarding the customer care initiatives, Mr. Mara agrees with the addition of the Energy Advisors but disagrees with adding the Energy Engineers at this time.

Dr. Karl Pavlovic has responded to Commission Issues Nos. 11, 13-16, 18b and 18c, concerning jurisdictional allocation, cost of service allocation and rate design. Dr. Pavlovic examined the Company's cost allocation and rate design proposals and draws several conclusions:

- Pepco over-allocates distribution costs to its D.C. jurisdiction.
- Any rate increase should be allocated to rate classes on a pro-rata basis; the Commission should not shift revenues from other classes to the residential class given the factors he identifies, including the District's economic climate.
- The Commission should open an inquiry into rate design after AMI is fully deployed in D.C.

- For rate design in this case, he recommends (1) for the customer classes with customer/kWh rate structures, the customer charge should be set to fully recover customer costs at the actual class rate of return with the remainder of the class revenue requirement recovered through the kWh charge; and (2) for customer classes with customer/demand/kWh rate structures, the customer charge and demand charges should be set to fully recover customer and demand costs at the actual class rate of return and the usage charge should be eliminated.

Dr. David Dismukes addresses Pepco's request to institute a new regulatory mechanism called the Reliability Investment Recovery Mechanism (RIM). Dr. Dismukes shows how, among other flaws, the proposed mechanism is at odds with good regulatory practice, is incomplete and not well-defined, is internally inconsistent, and fails to protect ratepayers. He concludes that Pepco does not need the RIM to undertake reliability investment and that the harm of this mechanism outweighs any benefits. If the Commission is inclined to adopt a RIM-like proposal, Dr. Dismukes offers numerous adjustments that must be made to Pepco's proposal in order that consumers are treated fairly.

VII. RECOMMENDATIONS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Office understands the Commission must balance the interests of ratepayers and the utilities that serve them. OPC understands the importance of maintaining a financially-healthy utility while providing consumers with safe, adequate and reliable service. OPC also knows that Pepco is a poorly performing utility when it comes to reliability and customer service.

In light of this understanding and the evidence presented by OPC in this case, the Commission should not reward Pepco for its poor performance by increasing the allowed rate of return or offering special regulatory treatment for investment that has been missing for years. The Commission should be consistently firm in its approach with Pepco and require that the Company meet its statutory mandate.

In its response to Pepco's filing, the Office of the People's Counsel has recommended adjustments that produce rates that are just and reasonable. OPC has crafted regulatory treatment for important investment in AMI and reliability investments that will permit those investments to go forward while protecting consumer interests and providing the correct incentives to Pepco.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

Washington)
District of Columbia) SS:

Ronald J. Binz, being first duly sworn, deposes and states that he is the Ronald J. Binz whose Testimony accompanies this Affidavit; that such testimony was prepared by him or under his supervision; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as true as his sworn testimony in this proceeding.

Ronald J. Binz

Subscribed and sworn before me this

7th day of December, 2011.

Erica C. Bright

Notary Public

My Commission Expires:

Erica C. Bright
Notary Public, District of Columbia
My Commission Expires 7/14/2013

ERICA C. BRIGHT
NOTARY PUBLIC
DISTRICT OF COLUMBIA

Exhibits of

OPC Witness

Ronald J. Binz

Appendix A

Ronald J. Binz
Public Policy Consulting
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Denver, Colorado 80220
720-425-3335 • rbinz@rbinz.com

Employment History

2011-present Principal, Public Policy Consulting

Following my four year term on the Colorado Public Utilities Commission, I have resumed my consulting practice in regulation of energy and telecommunications markets. In the energy area, my focus is on climate, clean tech, integrated resource planning and smart grid. In telecommunications, my focus is on adapting regulation to deal effectively with today's markets, emphasizing policies that accelerate the deployment of broadband services.

2011-present Senior Policy Advisor, Center for the New Energy Economy

The Center for the New Energy Economy (CNEE) at Colorado State University is headed by former Colorado Governor Bill Ritter, Jr. The Center provides policy makers, governors, planners and other decision makers with a road map to accelerate the nationwide development of a New Energy Economy.

2007-2011 Chairman, Colorado Public Utilities Commission

I was appointed by Governor Bill Ritter, Jr. in January 2007. As Chairman, I helped implement the Governor's and Legislature's vision of Colorado's New Energy Economy, implementing the state's 30% Renewable Energy Portfolio Standard, fulfilling the Commission's role in the Governor's Climate Action Plan, streamlining telecommunications regulation, promoting broadband telecommunications investment and improving the operation of the Commission.

Here are some major accomplishments during my term on the Commission:

- **Implementing the Clean Air-Clean Jobs Act (2010).** Following passage of this new law in 2010, the Commission worked under a very compressed time schedule to consider proposals by XcelEnergy and Black Hills Energy to reduce pollutants from their coal fired generation plants. The contentious Xcel proceeding involves thirty-four legal parties, testimony from sixty-one witnesses and the consideration of more than a dozen contending compliance plans. The case has required the close cooperation between the Commission and the Department of Public Health and Environment.

- **Implementing dozens of new energy, transportation and telecommunications laws.** In each legislative session during the term of Governor Ritter, the general assembly passed numerous utility-related laws. Many of these new laws require the Commission to adopt rules, compile reports, or conduct hearings. Rarely in Colorado history has there been this much activity required of the Commission.

- **Modifying and approving the electric resource plan of XcelEnergy (2009)**. After extensive hearings, the Commission approved a plan that includes large amounts of new wind capacity, the early closure of two coal power plants to reduce carbon and other emissions, the acquisition of 200-600 megawatts of solar thermal capacity, and substantial amounts of new energy efficiency savings. The target portfolio will reduce CO_2 emissions per megawatt-hour by 22% from current levels by 2017. The Commission decision requires competitive acquisition for new resources.

- **Adopting new, aggressive energy efficiency requirements (2008)** for Colorado gas and electric utilities. The Commission's requirements for electric utilities go well beyond the statutory minimum levels enacted in 2007. The Commission's policies also provide for rapid cost recovery of energy efficiency spending and bonus incentives for superior performance for the utilities.

- **Rewriting the Commission's electric resource planning rules (2007)** to require full consideration of future costs for carbon emissions, new clean energy resources and environmental and economic externalities. Retained and refined the requirements for competitive acquisition of new resources.

- **Improving communications with stakeholders.** I successfully sought legislation to modify the Commission's enabling statute, allowing the use of a "permit-but-disclose" communications process similar to the one employed successfully by the FCC and the FERC. The result has been much greater exposure of the Commissioners and staff (outside the hearing process) to the thinking of consumers, utilities, environmental advocates, large customers, advocates for new technologies, etc.

- **Organizing meetings of Western state regulators on regional transmission issues**. We discussed coordination in our efforts to add transmission capacity, especially to renewable energy zones. In future meetings we will discuss a goal of eliminating "pancaked" transmission pricing in the intermountain west.

- **Conducting hearings in eight towns around the state** on a "road trip" to collect consumer opinions about energy rates, distributed generation, the future of the energy sectors, and support for moving toward a more environmentally-sensitive utility industry.

- **Reorganizing the PUC's staff** to create a Research and Emerging Issues section. As chairman, I worked to improve deployment of the agency's modest staff so that the Commissioners could stay apprised of new technology and policy alternatives and be able to investigate and implement new regulatory approaches.

- **Reaching out to consumers and interest groups.** I frequently speak at meetings of consumer organizations, environmental groups, business and professional associations, legal seminars, etc. The two-way-street communications improves my understanding and conveys to the public the immense challenges we face in energy policy with climate change.

1995-2006 President, Public Policy Consulting

Consultant, specializing in energy and telecommunications regulatory policy issues. Assignments include strategic counsel to clients and research and testimony before regulatory and legislative bodies. In addition, I produced several research reports about the impact on rates of adding significant amounts of wind and solar capacity to utility systems. These reports are listed below.

I had a wide range of clients, including: consumer advocate offices, rural electric utilities, senior citizen advocacy groups, environmental groups, industrial electric users, homebuilders, building managers, telecommunications resellers, incumbent local exchange companies, low-income advocacy organizations, and municipal utilities. I have testified as an expert witness before regulatory commissions in twelve states.

1996-2003 President and Policy Director, Competition Policy Institute

Competition Policy Institute was an independent non-profit organization that advocated for state and federal policies to bring competition to energy and telecommunications markets in ways that benefit consumers. Duties included: determining the organization's policy position on a wide range of telecommunications and energy issues; conducted research, produced policy papers, presented testimony in regulatory and legislative forums, hosted educational symposia for state regulators and state legislators.

1984-1995 Director, Colorado Office of Consumer Counsel

Director of Colorado's first state-funded utility consumer advocate office. By statute, the OCC represents residential, small business and agricultural utility consumers before state and federal regulatory agencies. The office was a party to more than two hundred legal cases before the Colorado Public Utilities Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission and the courts.

Managed a staff of eleven, including attorneys, economists, and rate analysts who conduct economic, financial and engineering research in public utility matters. Testified as an expert witness on subjects of utility rates and regulation. Negotiated rate settlement agreements with utility companies. Regularly testified before the Colorado general assembly and spoke to professional business and consumer organizations on utility rate matters. Consulted with advisory board of consumer leaders from around the state.

Held leadership roles in National Association of State Utility Consumer Advocates. Member of high-level advisory boards to Federal Communications Commission (Network Reliability Council and North American Numbering Council) and Environmental Protection Agency (Acid Rain Advisory Council). Frequent witness before congressional committees and invited speaker before national industry and regulatory forums.

1977-1984 Consulting Utility Rate Analyst

Represented clients in public utility rate cases and testified as an expert witness in utility cases before regulatory commissions in Utah, Wyoming, Colorado and South Dakota. Clients included state and local governments, low income advocacy groups, irrigation farmers and consumer groups. Testimony spanned topics of telephone rate design, electric cost-of-service studies, avoided cost valuation of nuclear generation, electric rate design for irrigation customers and municipal water rate design.

1975-1984 Instructor in Mathematics

Taught mathematics at the University of Colorado, Denver and Boulder campuses. Nominated three times for outstanding part-time faculty member.

1971-1974 Manager, Blue Cross and Blue Shield

Managed major medical claims processing department. Responsibilities included budgets, hiring, training, managing supervisors, and coordinating with medical peer review committee.

Other Business Interests

1994-present Managing Partner, Trail Ridge Winery

Managing Partner and Secretary/Treasurer of Trail Ridge Winery. Trail Ridge is a Colorado winery located in Loveland, Colorado, producing a variety of award-winning wines from Colorado-grown grapes. Beginning in 2009, the winery has been reducing its production and will likely end operations in 2011.

Education

M.A. (Mathematics) 1977. University of Colorado. Course requirements met for Ph.D.

Graduate courses toward M.A. in Economics 1981-1984. University of Colorado. Twenty-seven hours including Economics of Regulated Industries, Natural Resource Economics, Econometrics.

B.A. with Honors (Philosophy) 1971. St. Louis University.

Diploma 1967. Catholic High School, Little Rock, Arkansas.

Professional Associations and Activities

Selected Current:

Harvard Electric Policy Group, John F. Kennedy School, Harvard University 1994-present

Advisory Council to the Board of the Electric Power Research Institute (EPRI) 2008-present

Keystone Energy Board 2009-present

Aspen Institute for Humanistic Studies, Communications and Society Programs 1986-present

Selected Past:

National Association of Regulatory Utility Commissioners
Member, Energy Resources and Environment Committee 2007-2011
Member, International Relations Committee 2007-2011
Chair, NARUC Task Force on Climate Policy 2010-2011
President, Western Conference of Public Service Commissioners, 2010-2011

Acid Rain Advisory Council to the Environmental Protection Agency, circa 1991
American Association for the Advancement of Science
American Vintners Association (*now* WineAmerica), Executive Committee, Membership Chair
Chair, Telecommunications Committee 1992-1995
Colorado Common Cause, Board Member
Colorado Energy Assistance Foundation, Board Member, Past President
Colorado Legislative Task Force on Information Policy, Gubernatorial Appointee 2000-2001
Colorado Public Interest Research Foundation, Board Member
Colorado Telecommunications Working Group, Gubernatorial Appointee
Colorado Wine Industry Development Board, Chairman
Council on Economic Regulation, Past Fellow
Denver Mayor's Council on Telecommunications Policy
Exchange Carriers Standards Association Network Reliability Steering Committee
Legislative Commission on Low-Income Energy Assistance, Past President
National Association of State Utility Consumer Advocates
President 1991-1992, Vice-President 1990, Treasurer 1987-1989
Network Reliability Council to the Federal Communications Commission
New Mexico State University Public Utilities Program, Faculty and Advisory Council
North American Numbering Council to Federal Communications Commission, Co-Chair
Outreach Committee, Western States Coordinating Council Regional Planning Committee
Total Compensation Advisory Council to the State of Colorado Department of Personnel
Who's Who in Denver Business

Selected Regulatory Testimony

From 1977 to 2011, Mr. Binz participated in more than 150 regulatory proceedings before the

Federal Communications Commission, the Federal Energy Regulatory Commission, State and Federal District Courts, the 8th Circuit, 10th Circuit and D.C. Circuit Courts of Appeal, the U.S. Supreme Court and state regulatory commissions in California, Colorado, Georgia, Idaho, Maine, Missouri, New York, North Dakota, South Dakota, Texas, Utah, and Wyoming. He has filed testimony in approximately sixty proceedings before these bodies. His testimony and comments have addressed a wide variety of technical and policy issues in telecommunications, electricity, natural gas and water regulation.

Before the Public Service Commission of Wyoming. In The Matter of Rocky Mountain Power's Confidential Contract Filing Docket No. 20000-379-EK-10 of a Purchase Power Agreement between PacifiCorp and Pioneer Wind Park I. Binz Affidavit on behalf of Northern Laramie Range Alliance. Record No. 12618 (August 2011)

Before the West Virginia Public Service Commission. In The Matter Of the Petition of Verizon West Virginia, Inc. To Cease Rate Regulation of Certain Workably Competitive Telecommunications Services. Case No. 06-0481-T-PacifiCorp (June 2006)

Before the Utah Public Service Commission. In The Matter Of The Division's Annual Review and Evaluation of Electric Lifeline Program, HELP Rate Design Testimony. Docket No. 04-035-21 (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Rebuttal Testimony. Docket No. 05F-167G. (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Direct Testimony. Docket No. 05F-167G. (June 2005)

Before the Michigan Public Service Commission. Testimony on behalf of the Michigan Attorney General. In The Matter Of SBC Michigan's Request For Classification Of Business Local Exchange Service As Competitive Pursuant To Section 208 Of The Michigan Telecommunications Act. Case No. U-14323. (March 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel. In the Matter of the Combined Application of Qwest Corporation for Reclassification and Deregulation of Certain Part 2 Products and Services and Deregulation of Certain Part 3 Products and Services. Docket No. 04A-411T. (February 2005)

Before the Utah Public Service Commission. In The Matter Of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Rate Design Testimony. Docket No. 04-035-42. (January 2005)

Before the Utah Public Service Commission. In The Matter Of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Revenue Requirements Testimony. Docket No. 04-035-42. (December 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Building Owners and

Managers Association of Metropolitan Denver (BOMA) in the Matter of The Investigation And Suspension Of Tariff Sheets Filed By Public Service Company Of Colorado With Advice Letter No. 1411—Electric Docket No. 04S-164E (October 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of The Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. Docket No. 04A-214E (filed: September 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of the Application of Public Service Company of Colorado For An Order Authorizing It To Implement A Purchased Capacity Cost Adjustment Rider In Its PUC No. 7 – Electric Tariff. Docket No. 03A-436E. (filed: March 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of Wyoming Industrial Energy Consumers (WIEC) and AARP In the Matter of the Application of PacifiCorp for Approval of a Power Cost Adjustment Mechanism. Docket No. 20000- ET-03-205 (filed: January 2004).

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel Regarding The Unbundling Obligations Of Incumbent Local Exchange Carriers Pursuant To The Triennial Review Order – Initial Commission Review. Docket No. 03I-478T. (January 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of The Application Of PacifiCorp For A Retail Electric Utility Rate Increase Of $41.8 Million Per Year Docket No. 20000-ER-03-198 (January 2004).

Before the Wyoming Public Service Commission. Public hearings testimony on behalf of AARP in the matter of an application by Kinder Morgan to modify the provider selection process in its Choice Gas Program. (December 2003).

Before the Public Service Commission of North Dakota. Testimony on behalf of AARP in the matter of In the Matter of the Notice of Montana-Dakota Utilities Co. for an Electric Rate Change. Case No. PU-399-03-296. (October 2003)

Before the Colorado Public Utilities Commission. Testimony in the matter of Public Service Company of Colorado's Advice Letter No. 598 – Natural Gas Extension Policy. Docket No. 02S-574G. (March 2003)

Before the Colorado Public Utilities Commission. Testimony in the remand hearings in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (January 2003)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning A Proposed General Rate Increase And Surcharge For Previous Power Costs. (November 2002).

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning Hunter Unit 1 Issues. (November 2002).

Before the Colorado Public Utilities Commission.. Comments on behalf of the Colorado Energy Assistance Foundation. Docket No. 02R-196G. In the Matter of the Proposed Repeal and Reenactment of the Rules Regulating Gas Utilities. (November 2002)

Before the Colorado Public Utilities Commission.. Testimony on behalf of Colorado Energy Assistance Foundation and Catholic Charities of the Archdiocese of Denver. Docket No. 02A-158E. In the Matter of the Application of Public Service Company of Colorado for an Order to Revise its Incentive Cost Adjustment. (April 2002)

Before the Idaho Public Utilities Commission. Testimony on behalf of Astaris, in the matter of Case No. IPC-E-01-43 concerning the buy-back rates under an electric load reduction program. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in matter of the investigation of Advice Letters 579 and 581 of Xcel Energy on behalf of Homebuilders Association of Denver. Dockets 01S-365G and 01S-404G. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (August 2001)

Before the Colorado Public Utilities Commission. Testimony in the matter of the investigation and suspension of Advice Letter No. 566 of Xcel Energy on behalf of the Homebuilders Association of Metropolitan Denver. Docket No. 00S-422G. (November 2000)

Before the American Arbitration Association. In the Matter of Univance Telecommunications, Inc. v. Venture Group Enterprises, Inc. Arbitration No. 77 Y 147 00099 00 (November 2000)

Testimony of Ronald Binz at FCC Public Forum on SBC/Ameritech merger (May 1999)

Docket No. 97-106-TC -- Testimony of Ron Binz before New Mexico State Corporation Commission on Investigation Concerning USWest's Compliance with Section 271(c) of the Telecommunications Act (July 1998)

Before the Colorado Public Utilities Commission. Testimony Concerning the Investigation of Telephone Numbering Policies. (March 1998)

Docket No. 6717-U X Testimony before the Georgia Public Service Commission Concerning the Service Provider Selection Plan of Atlanta Gas Company. (January 1997)

Case 96-C-0603 and Case 96-C-0599--Testimony of Ronald J. Binz on behalf of CPI before the New York State Public Service Commission concerning the Bell Atlantic/NYNEX Merger (November 1996)

Docket No. 96-388 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of the Office of the Public Advocate (October 1996) State of Maine, Public Utilities Commission Joint Petition of New England Telephone and Telegraph Company and NYNEX Corporation for Approval of the Proposed Merger of a Wholly-Owned Subsidiary of Bell Atlantic Corporation into NYNEX Corporation.

Application No. 96-04-038 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of Intervener, Utility Consumers Action Network (September 1996) Before the Public Utilities Commission of the State of California In the Matter of the Joint Application of Pacific Telesis Group (Telesis) and SBC Communications (SBC) for SBC to Control Pacific Bell (U 1001 C), Which Will Occur Indirectly as a Result of Telesis' Merger With a Wholly Owned Subsidiary of SBC, SBC Communications (NV) Inc.

Presentation to Federal-State Joint Board on Universal Service (April 12, 1996)

Testimony before the Texas Public Utility Commission on the Integrated Resource Planning Rule (March, 1996)

Congressional Testimony

Mr. Binz has testified fifteen times before U.S. House and Senate Committees. In addition, he has testified numerous times before state legislatures in several states. Here is a list of his U.S. Congressional testimony:

United States House of Representatives Commerce Committee, Energy Subcommittee, 2008. Testimony concerned a proposal to adopt a federal renewable energy standard.

United States House of Representatives Judiciary Committee, November 1999. Testimony concerning H.R. 2533, The Fairness in Telecommunications License Transfer Act of 1999.

United States Senate Judiciary Committee; Antritrust, Business Rights and Competition Subcommittee, April 1999. Testimony concerning S.467, The Antitrust Merger Review Act.

United States Senate Commerce Committee, Telecommunications Subcommittee, May 1998. Testimony in oversight hearings concerning the performance of the Common Carrier Bureau of the Federal Communications Commission.

United States Senate Judiciary Committee, Washington, D.C., September 1996. Presented testimony on behalf of the Competition Policy Institute on the competitive impact of proposed mergers of Regional Bell Operating Companies.

United States House of Representatives Subcommittee on Telecommunications and Finance of the Committee on Commerce, May 1995. Testimony presenting NASUCA's position on H.R. 1555 by Representative Fields.

United States Senate Subcommittee on Antitrust, Washington, D.C., September 1994. Testimony presenting NASUCA's position on S. 1822 by Senator Hollings.

United States House of Representatives Subcommittee on Telecommunications and Finance of the House Energy and Commerce Committee, Washington, D.C., February 1994. Presented testimony on H.R. 3636.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., October 1992. Supplemental testimony presenting NASUCA's position on legislation concerning the Modified Final Judgment introduced by Representative Brooks.

United States House of Representatives Subcommittee on Telecommunications and Finance, Washington, D.C., October 1991. Testimony on RBOC entry into telecommunications manufacturing and information services.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., August 1991. Testimony presenting NASUCA's position on possible federal legislation concerning the Modified Final Judgment.

United States Senate Subcommittee on Energy Regulation and Conservation, Denver, Colorado, April 1991. Testimony presenting NASUCA's position on federal legislation concerning regulation of the natural gas industry, introduced by Senator Wirth.

United States Senate Communications Subcommittee, Washington, D.C., February 1991. Testimony on behalf of NASUCA concerning S.173, telecommunications legislation introduced by Senator Ernest Hollings.

United States Senate Communications Subcommittee, Washington, D.C., July 1990. Testimony on behalf of NASUCA concerning S.2800, telecommunications legislation introduced by Senator Conrad Burns.

United States House of Representatives Subcommittee on Telecommunications and Finance, July 1988. Testimony on the FCC Price Cap proposal.

Reports and Publications

Mr. Binz produced two reports, funded by the Energy Foundation, of the impact of a renewable energy standard in Colorado:

The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado. **(September 2004)**

The Impact a Renewable Energy Portfolio Standard On Retail Electric Rates In Colorado. **(February 2004)**

Mr. Binz is the co-author, with Jane Pater, of a study, conducted for the InterWest Energy Alliance, of the fuel savings associated with the increased use of wind power in Colorado:

Wind on the Public Service Company of Colorado System: Cost Comparison to Natural Gas

Mr. Binz is the co-author of two major reports on electric industry restructuring:

Navigating a Course to Competition: A Consumer Perspective on Electric Restructuring.

Addressing Market Power: The Next Step in Electric Restructuring.

In the telecommunications area, Mr. Binz published a major discussion paper entitled ***Qwest, Consumers and Long Distance Entry: A Discussion Paper.***

Exhibits of

OPC Witness

Ronald J. Binz

Exhibit OPC (A)-1

Decision No. C09-1446

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 09AL-299E

RE: THE TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO WITH ADVICE LETTER NO. 1535 - ELECTRIC.

ORDER ADDRESSING PHASE I AND ECA ISSUES

Mailed Date: December 24, 2009
Adopted Dates: December 1, 3, and 22, 2009

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175. In this rate case and Public Service's previous rate case, we have strived to balance a number of potentially conflicting concerns: minimizing the impact on consumers; ensuring the electricity stays on; providing for the financial health of Public Service; and pursuing a clean energy strategy. We will be examining a program to be established by Public Service for its low-income electricity customers in the next Phase of this rate case that will hopefully provide some level of protection to those in need. This will parallel a similar program we have previously approved for gas customers.

G. Smart Grid City

176. One of the contested issues in this proceeding is whether a Certificate of Public Convenience and Necessity (CPCN) should be required for the SmartGridCity project in Boulder, Colorado. The two related issues are whether SmartGridCity is in the ordinary course of business and whether it is distribution-related.

177. In its pre-filed testimony, Public Service contended that SmartGridCity does not require a CPCN because it is an investment in the distribution system. Ms. Karen Hyde testified that "SmartGridCity is a distribution project and does not include any transmission or generating capacity. Under Rule 3207,[14] construction or expansion of the distribution system is deemed to be in the ordinary course of business and does not require a CPCN."[15] In addition, Mr. Randy Huston testified that "to the extent the project ties to any particular portion of our system, it is distribution related…much of our SmartGridCity project consists of software, which is general plant, not generation or transmission plant. I would add that much of this project is

[14] Rule 3207(a) states that "[e]xpansion of distribution facilities, as authorized in § 40-5-101, C.R.S., is deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity."

[15] Rebuttal Testimony of Karen Hyde, p. 18, lines 1-10.

integrating intelligence (communication and software) into the distribution system."[16] During the hearing, Mr. Huston further testified that the software included as part of SmartGridCity does have some implications in the generation area.[17] Mr. Huston clarified that when he was testifying whether SmartGridCity is distribution related, he was doing so from a systems engineering perspective rather than from an accounting perspective.[18]

178. The Settlement Agreement proposes that Public Service not be required to obtain a CPCN for SmartGridCity. It would allow Public Service to amortize the 2009 O&M expenses of $2.8 million over a two year period beginning January 1, 2010. In addition, the settlement's HTY includes recovery of $42 million plant in service as of December 31, 2009, and forecasted 2010 O&M expenses of $4.1 million. The Settlement Agreement further provides that Public Service will file an application with the Commission prior to any deployment of comprehensive smart grid technology outside of SmartGridCity. In its Motion In Support Of Settlement Agreement, Public Service argued that (1) "despite the admittedly innovative nature of the project, the Company believes that [Rule 3207(a)] allowed the Company to proceed with SmartGridCity without a CPCN;" (2) that "it is not outside the ordinary course of business for the Company to test and deploy new technologies of all forms on its system;" (3) that this docket has given the parties adequate opportunity to explore cost overruns experienced by the Company and that these costs have been adequately explained; and (4) that SmartGridCity is almost complete and little would be accomplished in requiring Public Service to obtain a CPCN after the fact. For its part, Staff, in its Statement in Support of Settlement Agreement filed on

[16] Rebuttal Testimony of Randy Huston, p. 15, lines 1-10.
[17] Transcript, October 30, 2009, p. 71, lines 14-15.
[18] *Id.*, p. 69, lines 21-22.

November 18, 2009, stated that the Settlement Agreement is responsive to its concerns regarding SmartGridCity.

179. The settlement represents a departure from Staff's position as presented in its pre-filed testimony. In its testimony, Staff argued that the Commission should require Public Service to obtain a CPCN for SmartGridCity because (1) although some elements of SmartGridCity are apparently part of the distribution system, other elements are not and the project as a whole spans several functional areas; and (2) SmartGridCity is not in the ordinary course of business because it is unique, largely untested, and many components of the project are not the typical equipment necessary in the provision of electric service in the ordinary course of business.[19] Staff further argued that the Commission should require a CPCN for policy reasons. First, ratepayers would benefit from a regulatory structure where costs are known and measurable. Further, a CPCN would allow the Commission to cap costs, monitor them in the future, and determine whether they are prudent and in the public interest. In addition, Staff argued that the ratepayers should benefit from intellectual property rights developed in the course of implementing the project.[20] Finally, Staff was unclear how much of the investment in SmartGridCity comes from ratepayers in rates versus contribution by shareholders.[21]

180. In addition, in its cross-examination of Ms. Hyde and Mr. Huston, Staff pointed out that SmartGridCity is different than most distribution systems in Colorado because (1) it enables customers to access energy use information; (2) it allows customers and the company to

[19] Answer Testimony of Harry DiDomenico, pp. 30-36.
[20] *Id.*
[21] *Id.*, p. 29.

control in-home energy management devices remotely; and (3) it may require laying of fiber next to existing distribution cables.[22]

181. The City of Boulder, the OCC, ACT, Ms. Glustrom[23] and Ms. Burchell argue a CPCN is required for SmartGridCity. In its testimony, Boulder argues that "the cost and magnitude of the proposed investment in SmartGridCity, coupled with its experimental character, are compelling reasons to require a CPCN."[24] In its SOP, Boulder contended that the assertions by Public Service that the project is distribution-related are not supported by evidence and that simply claiming that the project is not generation or transmission related does not make it distribution related. Boulder points out that because SmartGridCity will allow customers to adjust their energy consumption, an argument can be made that the project could also be related to generation plant since fewer plants will need to be built to accommodate demand for energy. In its SOP, Boulder further argues that SmartGridCity is not in the ordinary course of business because Public Service has partnered with private equity partners, which it probably would not do if it was simply expanding its distribution system. Boulder also argues that SmartGridCity is not in the ordinary course of business because intellectual property rights, which presumably are addressed in the agreements between Public Service and private equity partners, are not usually at issue in the agreements that Public Service enters into with contractors and subcontractors when expanding its distribution system.

[22] Transcript, October 26, 2009, pp. 129-130 and October 29, 2009, p. 178.

[23] In her cross-examination of Public Service's witness Mr. Huston, Ms. Glustrom offered Exhibit 136, a news article from the Associated Press entitled *Colo. Cities Receive $24.2 Million for Smart Grid.* Public Service objected to the admission of this Exhibit, arguing Mr. Huston was unfamiliar with the projects described in the article. The Commission agreed, and excluded Exhibit 136.

[24] Cross-Answer Testimony of Jonathan Koehn, p. 5, lines 6-7.

182. For its part, the OCC opines that SmartGridCity should not be included in HTY cost of service if in fact it was constructed in the ordinary course of business (unlike Comanche or Fort St. Vrain).

183. In its supplemental SOP, ACT takes issue with the provision in the Settlement Agreement that "Public Service will file an application outlining scope, technology and expected costs with the Commission prior to any deployment of comprehensive smart grid technology outside of SmartGridCity." It argues that the terms "application" and "comprehensive smart grid technology" are not well-defined. ACT also points out that this provision may allow further deployment of SmartGridCity technology *in* Boulder and could result in additional expenditures without prior Commission oversight. ACT also argues that SmartGridCity is not a "distribution facility" as that term is defined by the Commission's Rules and that meters are excluded from the definition of "distribution extension."[25] Finally, ACT argues that the Commission may not, via the Settlement Agreement, exempt Public Service from obtaining a CPCN for SmartGridCity.

184. Section 40-5-101(1), C.R.S., states that "[n]o public utility shall begin the construction of a new facility, plant, or system or of any extension of its facility, plant, or system without first having obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction." The statute does not require utilities to obtain a CPCN "for an extension within any city and county or city or town within which it has theretofore lawfully commenced operations, or for an extension into territory,

[25] Rule 3001(i) defines a distribution extension as "any construction of distribution facilities, including primary and secondary distribution lines, transformers, service laterals, and appurtenant facilities (except meters and meter installation facilities), necessary to supply service to one or more additional customers." Rule 3001(j) defines distribution facilities as "those lines designed to operate at the utility's distribution voltages in the area as defined in the utility's tariffs including substation transformers that transform electricity to a distribution voltage and also includes other equipment within a transforming substation which is not integral to the circuitry of the utility's transmission system."

either within or without a city and county or city or town, contiguous to its facility, line, plant, or system and not theretofore served by a public utility providing the same commodity or service, or for an extension within or to territory already served by it, necessary in the ordinary course of its business." *Id.* The Commission has discretion to award a CPCN retroactively, even if construction for a project has begun, if it determines, based on evidence in the record, that issuance of a CPCN will serve the public interest. *City of Boulder v. Pub. Utils. Comm'n*, 996 P.2d 1270, 1276 (Colo. 2000).

185. Previous Commission decisions identify several factors relevant in determining whether the project is in the ordinary course of business pursuant to § 40-5-101(1), C.R.S.: (1) whether it is necessary to serve load growth; (2) size, cost and magnitude of the project; (3) the presence of novel financing arrangements, which usually indicate that the project is not in the ordinary course of business; (4) whether the project from other distribution system expansions in the ordinary course of business to serve current and anticipated customers.[26] The Commission also previously stated that normal course of business includes only that which is routine, ordinarily-occurring, and usual for the business under review.[27] The Commission finally stated that the assessment of whether a project is in the ordinary course of business must be made on a case-by-case basis.[28]

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[26] Decision No. R08-0925, at ¶¶28-23, affirmed by the Commission in Decision No. C09-0365 (discussing whether planned construction of certain natural gas pipeline laterals by Atmos Energy Corporation would be in the ordinary course of business). Decision No. R08-0925 was part of Docket No. 08F-033G, in which Public Service argued construction of the proposed gas pipeline laterals required a CPCN.

[27] Decision No. R05-1224 (discussing whether the sale of a substation and related facilities and equipment would be in the ordinary course of business).

[28] Decision No. C09-0365, ¶ 25.

186. We agree with Boulder and other interveners that a CPCN for SmartGridCity is necessary prior to cost recovery.[29] First, SmartGridCity is not in the ordinary course of business because of (a) its cost and magnitude ($42 million); (b) its uniqueness, including the fact that many of the technologies are being deployed for the first time; and (c) elaborate financing and intellectual property arrangements.

187. Second, we find SmartGridCity is not simply a distribution project. For example, Mr. DiDomenico testified that the project spans several functional areas and Mr. Houston testified that it has some implications in the generation area. We also agree with ACT that SmartGridCity does not fit neatly into the definition of "distribution facility" or "distribution extension" as these terms are defined by the Commission's Rules. The exemption pursuant to Rule 3207(a) therefore does not apply, at least in part, to SmartGridCity. Finally, any reliance on Rule 3207(a), to the extent that it applies *and* is inconsistent with or goes beyond the scope of § 40-5-101(1), C.R.S., is misplaced since a rule cannot contravene a statute.

188. We therefore find a CPCN is required by statute for SmartGridCity. Besides being required by law, the CPCN proceeding will allow the Commission to examine whether the costs incurred are prudent and in the public interest, and to monitor these costs in the future. We therefore order Public Service to file an application for a CPCN for SmartGridCity.

189. We are cognizant of the fact that SmartGridCity is the first project of its kind in the nation. We believe the smart grid concept holds great promise and we wish to encourage innovation and energy efficiency from the utilities we regulate. We prefer a forward-looking approach to address the situation at hand, even though we would have preferred Public Service to

[29] Commissioner Baker would not require a CPCN for SmartGridCity, believing the Commission could have satisfied its obligation to approve plant in service without a formal CPCN proceeding.

have filed its application for a CPCN for SmartGridCity earlier. For this reason, and without prejudging the merits of the CPCN proceeding, we will permit Public Service to recover the costs associated with the project pending the CPCN proceeding, subject to refund if the CPCN application is not granted.

190. We also intend to open a separate investigatory or miscellaneous docket to explore the issues related to performance of SmartGridCity as a pilot project, and to address such issues as the lessons learned, technical specifications and how SmartGridCity might progress from a pilot to system-wide implementation. We will issue a decision opening this docket in the near future, outlining in more detail the scope of issues we wish to examine. This docket may or may not proceed contemporaneously with the CPCN docket and we will balance the need to examine overlapping issues holistically, on one hand, and the need to issue an order in the CPCN docket in a timely manner and the need to remove regulatory uncertainty, on the other hand.

H. Future Rate Cases

1. Limitation on Future Filings

191. Parts of the Settlement lay out some guidance regarding the timing of the next rate case. The Settlement states:

> The Company agrees that it will not file its next electric retail base rate case filing until such case is needed to effect rate changes due to the expiration of the power sales agreement with Black Hills/Colorado Electric Utility Company, L.P. (currently anticipated to expire on December 31, 2011), provided that, the Company shall be entitled to seek relief by proposing an alternative mechanism to recover any potential incremental costs associated with the recent Resource Plan Order (Decision No. C09-1257) that would traditionally be recovered in base rates within this time frame or to recover unanticipated costs caused directly or indirectly by government action and resulting in material changes to the Company's expenses or investments.

Settlement Agreement, p.16.

Exhibits of

OPC Witness

Ronald J. Binz

Exhibit OPC (A)-2

Decision No. C11-0139

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 10A-124E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING A SMARTGRIDCITY CPCN.

ORDER ON EXCEPTIONS

Mailed Date: February 8, 2011
Adopted Date: January 5, 2011

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that the lessons learned from SGC will be available to all of Xcel Energy's customers, not just those in Colorado, therefore it is unfair to assess all cost recovery on Colorado ratepayers.

15. Ms. Glustrom opposes virtually any cost recovery for SGC except for a small amount associated with the substation aspects of the project. She argues Public Service did not handle the budget and technical aspects of the project in a prudent manner. Ms. Glustrom also concurs with Climax and CF&I that the project is R&D and therefore is ineligible for recovery from the ratepayers.

2. Discussion

16. We deny the exceptions filed by the OCC, Climax and CF&I, and Ms. Glustrom on the issue of cost recovery. Public Service apparently experienced difficulties with the planning and budgeting of the project, and the costs associated with the project quickly escalated from March 2008 to the filing of the Application in this docket. However, standing alone, that does not mean necessarily that the Company acted imprudently.

17. That said, we are concerned whether SGC is today slated to achieve enough of its potential to justify its higher-than-anticipated costs. We are concerned whether SGC will become an integral part of the distribution system on a going-forward basis. We believe that, in a very real sense, the project is still in the development stage and that Public Service has not yet fully evaluated the capabilities of SGC nor has the Company assured us that those capabilities will likely be realized.

18. The Settlement Agreement requires Public Service to report on the value propositions of SGC to the Commission within 60 days of completion.[2] However, it

[2] Settlement Agreement, Section 6, August 27, 2010.

does not explicitly require Public Service to finish its analysis of the value propositions and report the same to the Commission. Neither does the settlement speak to the scope, quality, completeness, or the application of the analysis.

19. We are also concerned with the relative lack of details regarding the planned use of the project going forward. We recognize the merits of both the value proposition analysis and the pricing pilot, but we believe additional information is necessary regarding the project. We believe it is important for the SGC project to achieve benefits in a cost-effective manner. In short, we want to see the Company articulate and defend a strategic plan for the use of SGC investment. We want to see the credible promise of consumer and utility benefits sufficient to justify the cost overruns. We want to know more about the ability of customers to make practical use of SGC on their side of the meter through in-home devices, and we want to know more about the interconnect ability of SGC with those customer devices.

20. We will cap the recoverable investment at $27.9 million unless and until the Company demonstrates to our satisfaction that it has completed the unfinished aspects of the SGC project.

21. We find that the record evidence about the future use of SGC is sparse. The most tangible portion of that information addresses the pricing pilot and the planned report to the Commission on the value propositions. This approximates the modified scope of the project when it was considered in March 2009. At that time the capital cost of the project was $27.9 million and we therefore deem that level of investment to be prudent at this time.

22. To assist in developing a robust strategic plan for SGC and in identifying a suite of future applications, Public Service should use such techniques as an advisory group of academics, researchers, and customers. The Company should also avail itself of

Commission Information Meetings to keep the Commission informed of its progress and to solicit ideas for future applications of the SGC technologies.

23. In sum, this Commission believes that the Company needs to "re-boot" the SGC project and restore some of the promise this concept originally held. If the Company demonstrates in a future application[3] that the SGC project has a coherent and valuable future, we may allow the Company to recover the balance of the investment disallowed in this case.

E. Other Exceptions Filed by the OCC

24. The OCC argues that the final cost estimate of $44.8 million provided by Public Service (as well as the $44.5 million provided for in the Settlement Agreement) are based on the 20/20 hindsight since that amount represents actual costs instead of pre-construction estimates.[4] The OCC argues that the Company's request that $44.8 million (and the $44.5 million provided for in the Settlement Agreement) be deemed prudent was not consistent with the earlier rulings of the Commission that the prudency of the decision to undertake the project should be evaluated on "whether the action (or lack of action) of a utility was reasonable in light of the information known, or should have been known, at the time of the action. . ."[5] The OCC argues that the ALJ in fact used 20/20 hindsight to evaluate the Application.

25. In response, Public Service argues that the flaw in the OCC's argument is that it focuses only on the initial planning stage, and excludes the implementation stage. Further, the Company points out that the Commission has made clear that the prudence of SGC at both stages is relevant. *See* Decision No. C10-0729, mailed July 14, 2010, at ¶ 40.

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[3] Such future application should at a minimum, summarize how advisory groups are being engaged, identify smart grid investments and how such investments (or the Knowledge gained) will benefit customers and grid operations.

[4] Hearing Exhibit 9, Rebuttal Testimony of Mr. Scott Wilensky, p.16, line 15.

[5] Decision No. R10-0546-I, p.7, ¶17.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	Formal Case No. 1087
Power Company for Authority to Increase Existing	)	
Retail Rates and Charges for	)	
Electric Distribution Service	)	

DIRECT TESTIMONY AND EXHIBITS
OF
DONNA RAMAS
EXHIBIT OPC (B)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

DECEMBER 14, 2011

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DIRECT TESTIMONY OF DONNA RAMAS

I. INTRODUCTION

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

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and a Senior Regulatory Analyst with the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (such as public counsels, public advocates, consumer counsels, and attorneys general). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit OPC (B)-6, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Office of the People's Counsel of the District of Columbia ("OPC" or "Office").

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR SUPERVISION AND CONTROL?

A. Yes, they were.

II. <u>SCOPE OF TESTIMONY</u>

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

A. The purpose of my testimony is to present my recommended adjustments to Potomac Electric Power Company's ("Pepco" or "Company") proposed distribution rate base and distribution net operating income. I also present a quantification of the overall revenue requirement impact of my recommendations, along with the recommendations of other witnesses retained by OPC in this case who address issues that impact Pepco's proposed revenue requirement.

Q. WHICH OF THE ISSUES DESIGNATED BY THE COMMISSION FOR HEARING IN THIS PROCEEDING DOES YOUR TESTIMONY ADDRESS?

A. Attachment A to the District of Columbia Public Service Commission's ("PSC" or "Commission") October 3, 2011, Order and Report on Prehearing Conference, Order No. 16570, specifies the Designated Issues in this case. My testimony addresses Issues Nos. 1 – increase in distribution rates, 2 – test year, 2(a) adjustments to test year, 2(b) - budget or forecasted portion of the test year, 3 – rate base, 3(a) – projected plant additions and retirements, 3(b) – adjustments to average test year rate base, 3(c) - cash working capital, 4 – sales and revenues, 4(a) – weather normalization, 5 – operating expenses, 6 – depreciation adjustments, and 9(b) – accounting treatment of old meters. I address below the substance of each of these issues, and the positions that OPC recommends the Commission adopt with respect to each of them. I also recommend an adjustment to the regulatory asset associated with the implementation of the Advanced Metering Infrastructure ("AMI") implementation, which falls under issue 9. OPC Witness Kevin Mara will also be addressing issue 9 in his direct testimony. Additionally, I quantify the impact of OPC Witness Ron Binz's recommendation regarding the depreciation on AMI meters, which falls under issue 9(c).

Q. PLEASE BRIEFLY DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. There are 25 exhibits attached to my testimony, as follows:

Exhibit OPC (B)-1: Ratemaking Results and Revenue Requirement

Exhibit OPC (B)-2: Summary of OPC Adjustments

Exhibit OPC (B)-3: Revenue Requirements of Adjustments

Exhibit OPC (B)-4: Schedules 1 – 14, Individual Adjustments to Rate Base and Net Operating Income

Exhibit OPC (B)-5: Comparison of Actual to Forecast Plant Additions

Exhibit OPC (B)-6: Experience and Qualifications

Exhibits OPC (B)-7 through OPC (B)-25: Referenced responses to Discovery

The contents of the first four of these exhibits are reviewed below.

III. <u>SUMMARY OF TESTIMONY</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. OPC is recommending an increase in electric distribution rates, giving effect to all adjustments quantified at this time, of $8,786,000, which is $33,737,000 less than the $42,523,000 increase requested by the Company. The details behind this recommendation are provided in my testimony and the attached exhibits. In brief:

- Exhibit OPC (B)-1 presents the Company's proposed and OPC's recommended distribution rate base and net operating income for the 12 months ended September 30, 2011.
- Exhibit OPC (B)-2 presents a summary of all OPC adjustments to Pepco's proposed rate base, revenues, expenses and taxes, along with the net income effect of each adjustment that has been quantified to date. This includes the

adjustments I am sponsoring, which are explained in my testimony, along with the adjustments presented in the direct testimony of OPC Witnesses Ron Binz, Nancy Bright and Kevin Mara.

- Exhibit OPC (B)-3 presents the revenue requirement effect of each of OPC's recommended adjustments to Pepco's proposed distribution rate base, net operating income and rate of return. I note that the revenue requirement impacts that result from the implementation of OPC's recommended rate base adjustments are calculated using the overall rate of return recommended by OPC Witness Dr. J. Randall Woolridge.

- Exhibit OPC (B)-4 presents Schedules 1 through 14, consisting of supporting calculations for the various adjustments I am recommending in this testimony. Also included are several schedules which quantify the test year impact of recommendations made in the testimony of OPC Witnesses Ron Binz and Kevin Mara.

IV. DISCUSSION

Issue 1 – Base Distribution Rates

Q. WOULD YOU PLEASE ADDRESS ISSUE 1, WHICH ASKS: "IS PEPCO'S PROPOSED $42,101,000 INCREASE IN BASE DISTRIBUTION RATES JUST AND REASONABLE?"

A. In the Supplemental Direct Testimony of Pepco Witnesses Anthony J. Kamerick and Linda J. Hook, the Company updated its proposed increase in base distribution rates from the $42,101,000 presented in its initial filing to an updated request of $42,523,000, an increase of $422,000. As indicated above, OPC is recommending an increase in base electric distribution rates, giving effect to all adjustments quantified at this time, of $8,786,000 which is $33,737,000 less than the $42,523,000 updated increase requested by the Company.

The determination of the recommended increase in rates is based upon OPC's recommended distribution rate base of $1,136,310,000, OPC's adjusted net distribution operating income (prior to change in rates) of $78,037,000, and a recommended rate of return of 7.32%. The recommended rate of return of 7.32% is sponsored by OPC Witness Dr. J. Randall Woolridge. The recommended rate base and adjusted net operating income are addressed in this testimony and the exhibits attached hereto.

Q. DOES OPC'S RECOMMENDED REVENUE REQUIREMENT INCLUDE THE IMPACT OF THE CHANGES IN THE JURISDICTIONAL ALLOCATION FACTORS RECOMMENDED IN THE TESTIMONY OF OPC WITNESS KARL PAVLOVIC?

A. No, it does not. To the extent that the Commission requires Pepco to change any jurisdictional allocation factors as a result of OPC Witness Pavlovic's recommendations, there would be an additional reduction in D.C. jurisdictional revenue requirements that is not reflected in my testimony. Mr. Pavlovic has estimated the impact on the Company's unadjusted operating income as approximately $100,000.

<u>Issues 2, 2(a) and 2(b) – Test Year</u>

Q. **PLEASE ADDRESS ISSUE 2, WHICH ASKS: "IS PEPCO'S PROPOSED TEST YEAR ENDING SEPTEMBER 30, 2011, REASONABLE?"**

A. Pepco's proposed rate increase is calculated using a 12-month test year ending September 30, 2011, which consists of six months of actual data (October 1, 2010 through March 31, 2011) and six months of projected data (April 1, 2011 through September 30, 2011). I do not favor the use of a test year consisting of half-actual and half-projected data because I believe it is preferable to utilize a test year based on recent, actual, and verifiable data. Similarly, the Commission "prefers" the use of a historical test year, but permits one that is composed in part of actual and in part of forecasted data. Specifically, Commission Rule 15-200.4 states:

> The historical test year is the preferred proposed test year. However, the proposed test year may include forecasted data; Provided, that the proposed test year does not include more than six (6) months of forecasted data.

In Pepco's last distribution rate case, FC 1076, a historic test year was used. However, in the case immediately prior to that, FC 1053, Pepco proposed a test year consisting of six months of actual data and six months of forecasted data. In its decision in FC 1053, Order No. 14712, at page 10, the Commission determined that Pepco's proposed test year was appropriate, stating that "Commission Rule 213.2 clearly permits Pepco to use up to six months of forecasted test-year data."

Given that the Commission's Rules allow for a partially forecasted test year, the OPC does not challenge in this case Pepco's use of a proposed test year ending September 30, 2011. However, as will be addressed later in this testimony, several adjustments need to be made to the data in the forecast portion of the test year to make them more reasonable and more reflective of both test year conditions and the rate effective period.

Q. PUTTING ASIDE THE COMMISSION RULE, ARE THERE OTHER REASONS THAT LEAD YOU TO CONCLUDE THAT PEPCO'S USE OF A PARTIALLY FORECASTED TEST YEAR SHOULD NOT BE CHALLENGED?

A. Yes. By the time Pepco filed its case on July 8, 2011, three months of the forecast portion of the test year, or 50% of the forecast period, had already passed. Through the discovery process, the OPC was able to obtain actual data for much of the forecasted period that was incorporated in the test year. This allowed me to compare, in many areas, forecasted amounts to actual amounts, giving me the opportunity to evaluate the reasonableness of the forecasted data used by Pepco in its filing. I am recommending that adjustments be made in several rate base and net operating income areas in which there were large variances between forecasted amounts and actual amounts. The ability to conduct these evaluative comparisons and suggest recommended adjustments is another reason why OPC is not challenging Pepco's proposed test year.

Q. WERE YOU ABLE TO QUANTIFY ALL OF THE ADJUSTMENTS THAT ARE NEEDED TO ADDRESS THE LARGE VARIANCES BETWEEN THE FORECASTED AMOUNTS AND THE ACTUAL AMOUNTS IN THIS CASE?

A. Yes, with one caveat. As will be addressed later in this testimony, I am proposing an adjustment to the forecasted data on net plant additions because Pepco's forecast appears to have overstated significantly the actual level of plant additions. However, because Pepco has not provided the requisite information, my District of Columbia distribution level adjustment is an estimate based on the level by which Pepco over-projected the net plant additions during that same period on a total Company basis. Under the circumstances, my adjustment is reasonable and should be implemented.

Q. ISSUE 2(A) ASKS: "ARE THE PROPOSED ADJUSTMENTS TO THE TEST YEAR DATA FOR KNOWN AND MEASURABLE CHANGES REASONABLE?" WOULD YOU PLEASE ADDRESS THIS ISSUE?

A. OPC has reviewed all of Pepco's proposed adjustments and is recommending modifications and revisions to several of Pepco's proposed adjustments that impact rate base and net operating income. Later in this testimony I present each of OPC's recommended adjustments to the test year rate base and test year net operating income.

Q. WOULD YOU PLEASE ADDRESS ISSUE 2(B), WHICH ASKS "ARE PEPCO'S BUDGETED OR FORECASTED AMOUNTS FOR THE FORECASTED PORTION OF THE PROPOSED TEST YEAR (APRIL 2011 THROUGH SEPTEMBER 2011) REASONABLY FORECASTED AND BASED ON REASONABLE PROJECTIONS?"

A. According to the Direct Testimony of Pepco Witness Linda J. Hook, PEPCO (F), page 5, lines 3 – 4, "The six months of projected data were based on the Company's 2011 budgeted data." Thus, in order to answer whether or not the forecasted portion of the test year is reasonably forecasted or based on reasonable projections, it is necessary to evaluate the reasonableness of the Company's 2011 budgeted data.

Q. WERE YOU ABLE TO EVALUATE THE REASONABLENESS OF THE COMPANY'S 2011 BUDGETED DATA AS IT WAS USED IN DETERMINING THE FORECASTED PORTION OF THE PROPOSED TEST YEAR?

A. Pepco has provided only summary information in support of its 2011 budgeted data. As I explain immediately below, the information provided by Pepco does not demonstrate how the budgeted data were used to derive the forecasted test year amount.

Q. PLEASE ELABORATE.

A. OPC Data Request 1, Question No. 49(a) asked the Company to provide the 2011 operating and capital budgets "...in the most detailed format available." Question No. 49(b) also asked the Company to show, in detail, how the budgets being provided in response to 49(a) were used to determine the six months of projected data contained in the filing. The question also asked for all workpapers, calculations and assumptions that were used to go from the 2011 budget to the April 1, 2011 through September 30, 2011 amount incorporated in the filing. To obtain even more detailed information, Question No. 49(c) asked Pepco to identify all changes or modifications made to the 2011 capital and operating budgets for purposes of preparing the company's filing and determining the projected April 2011 through September 2011 amounts incorporated in the filing if those changes and modifications were not clear from the information being provided in response to Questions 49(a) and (b).

Thus, the question sought full detail for the 2011 budget data that was used to determine the amounts incorporated by Pepco in the forecast portion of the test year, and specifically asked Pepco to show how that information was used to go from the 2011 budget to the 2011 forecast amounts in the filing.

In response to the request for the 2011 operating and capital budgets "in the most detailed format available," Pepco provided 3 pages. One page was provided as Pepco's capital budget, one page was provided as Pepco's operating budget, and one page was provided as the Shared Service budget. In response to subparts (b) and (c), which sought detailed information and workpapers showing how the budgets were used to determine the test year amounts in the filing, Pepco responded as follows:

> Pepco's 2011 Capital Budget, which was approved by the Board in January 2011, was prepared during the fall of 2010. It was based on calendar year 2010, comprised of actual capital spending as of August 2010 and projected expenditures for September through December 2010.

> In putting together the 6 months actual, 6 months projected September 2011 test period, it was necessary to update the 2011 Budget for actual capital expenditures that had occurred from September 2010 through March 2011, rather than use the projected capital expenditures developed during and for the 2011 Budget process. Capital expenditures for the remaining months of April through December 2011 were then re-forecast to reflect the impact of updating September 2010 through March 2011 to actual.

No further details were provided in the response. While the response indicated that modifications were made to the capital budget and that the April through December 2011 amounts were then "re-forecast" to derive the forecast period amounts, those modifications and details regarding the "re-forecast" were not provided with the response. Pepco's full response to OPC Data Request 1, Question No. 49, with all subparts and attachments, is being provided as OPC Exhibit (B)-7, attached to this testimony.

Q. WAS ADDITIONAL INFORMATION REGARDING THE FORECASTED AMOUNTS INCLUDED IN THE TEST YEAR PROVIDED IN THE COMPLIANCE FILING?

A. Some additional information was provided with Pepco's Compliance Filing and in the electronic workpapers provided by Pepco in response to OPC Data Request 1, question 1. While the compliance filing information provided further breakdowns of projected revenues and expenses by FERC account by month, it did not show how the budgeted or forecasted amounts were determined by Pepco. For the most part, the underlying data and assumptions used in the budgeting processes were not provided.

Q. GIVEN PEPCO'S FAILURE TO PROVIDE COMPLETE AND DETAILED INFORMATION SUPPORTING THE FORECAST PORTION OF ITS TEST YEAR AND THE UNDERLYING ASSUMPTIONS ISN'T PEPCO'S PROPOSED TEST YEAR UNREASONABLE?

A. Yes, it is, and the Commission may wish to consider in this case requiring the use of a fully historic test year. However, I note that through discovery OPC was able to obtain additional information on specific net operating income and rate base items that allowed OPC to evaluate some – but not all – of the components of the forecast portion of Pepco's request. Additionally, through responses to OPC discovery requests, much actual information has been provided for the previously-forecasted amounts incorporated in the filing, allowing me to compare many of the forecasted balances to actual amounts and thereby to evaluate the reasonableness of Pepco's forecast. As indicated earlier, I am recommending several adjustments to some of the forecast amounts contained in Pepco's filing later in this testimony. Absent these data, which OPC obtained from Pepco, there would be no legitimate basis on which the Company could propose the use of a test year based in part on forecasted data.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS FOR THE COMMISSION'S CONSIDERATION AS IT PERTAINS TO TEST YEAR ISSUES?

A. Yes. Pepco's failure to provide adequate underlying support with regards to the forecast portion of the test year in this case, and its recalcitrance in answering requests for more detailed supporting information for forecasted amounts, has made it more difficult for OPC to advise the Commission on the propriety of Pepco's requested rate increase. It has also made it impossible to precisely calculate the District of Columbia jurisdictional allocation of the adjustment needed to replace Pepco's excessive forecast of plant additions during the second half of the test year with the actual plant additions during that six-month period. This issue was discussed briefly above and will be reviewed in more detail later in this testimony. In light of what has transpired so far in this proceeding, I recommend that as part of the Commission's decision on the merits in this case that Pepco be put on notice that it will be required to include much more detailed information as part of any future rate case filings in which the Company proposes the use of a partially forecast test year. Specifically, Pepco should be required to provide detailed budget assumptions and supporting data sufficient to enable intervenors and the Commission to gain an understanding of (a) how the Company developed its forecasts or budgets and (b) how it derived the amounts included in its proposed revenue requirement from those forecasted or budgeted figures.

Issue 3 – Rate Base

Q. PLEASE ADDRESS ISSUE 3, WHICH ASKS, "IS PEPCO'S PROPOSED RATE BASE JUST AND REASONABLE?"

A. OPC is recommending several adjustments to the Company's proposed rate base in this case. The Company has proposed a rate base of $1,172,025,000. OPC's rate base, giving effect to all adjustments proposed by OPC that have been quantified at this time, is $35,715,000 less than the amount proposed by the Company, resulting in an OPC recommended rate base of $1,136,310,000.

Exhibit OPC (B)-2, column (A) presents a summary of the individual adjustments to the Company's proposed rate base sponsored by OPC. I will review each of these adjustments in this testimony. Under Issue 3(b), I provide a listing of all adjustments the OPC is recommending to rate base at this time. I also address Issues 3(a), (b) and (c) in this testimony.

OPC Witnesses Nancy Bright and Kevin Mara also sponsor adjustments to rate base, and an adjustment recommended by Ron Binz impacts the accumulated depreciation component of rate base. The dollar impact of their adjustments is included in my Exhibit OPC (B)-2. I quantify the impact of adjustments recommended by Kevin Mara and Ron Binz which impact rate base in Exhibit OPC (B)-4, Schedules 10, 11 and 14.

<u>Issue 3(a) – Forecast Plant Additions and Retirements</u>

Q. ISSUE 3(A) ASKS "ARE THE PROJECTED PLANT ADDITIONS AND RETIREMENTS FOR THE FORECASTED PORTION OF THE PROPOSED TEST YEAR, I.E., APRIL 2011 THROUGH SEPTEMBER 2011, REASONABLY PROJECTED?" WHAT IS YOUR POSITION ON THIS ISSUE?

A. My position is that the forecasted plant additions contained in Pepco's filing are not reasonably projected and appear to be overstated significantly. The actual plant additions on a total Company basis for each month of the forecast period, April 2011 through September 2011, were significantly lower than the forecasted amount contained in Pepco's filing.

Q. ON WHAT DO YOU BASE YOUR ASSERTION THAT THE ACTUAL PLANT ADDITIONS IN THE FORECAST PORTION OF THE TEST YEAR WERE SIGNIFICANTLY LOWER THAN THE FORECAST AMOUNTS CONTAINED IN PEPCO'S FILING?

A. In its Compliance filing, Section 206.27, Attachment B, Pepco provided the projected test year plant additions and plant retirements on a total Company basis. The amounts were separately provided for transmission, distribution, general and intangible plant. OPC Data Request 3, Question 23, asked Pepco to provide a revised version of the information providing a monthly breakdown of the additions and retirements for each month of the test year. This would include both the actual portion of the test year and the forecast portion. The response is provided as Exhibit OPC (B)-10, attached to this testimony. The response included the projected additions and projected retirements for each of the forecast months, or April 2011 through September 2011, on a total Pepco basis.

As part of its response to OPC Data Request 3, Question No. 21[1], the Company provided the actual additions and retirements, on a total Company basis, for April, May and June, 2011. In response to OPC Data Request 13, Question 21, being provided as Exhibit OPC (B)-12, Pepco provided the actual plant additions and retirements for the remaining months of the test year, or July through September 2011.

On Exhibit OPC (B)-5, I provide a comparison, on a total Company basis, of the actual and projected plant additions, plant retirements, and net plant additions for each month, April 2011 through September 2011. I also provide a column showing the total projected amounts for the forecast period April 2011 through September 2011 as compared to the total actual amounts for that same period. As shown on the exhibit, net plant additions for the six month period ended September 30, 2011 was $132,520,861, which is $115,447,945 less than the budgeted amount for that period of $247,968,806. In other words, the actual net plant additions were only 53.4% of the forecasted amount. The exhibit also shows that the distribution plant additions, on a total Pepco basis, were $58,028,945, which is $78,398,513 less than the forecasted amount for that same period. The actual total Company distribution plant additions were only 42.5% of the forecasted amount for that same period.

Q. HAS PEPCO EXPLAINED WHAT FACTORS HAVE CAUSED THESE LARGE VARIANCES IN PLANT ADDITIONS?

A. No. OPC Data Request 13, Question No. 14[2], asked Pepco to explain, in detail, what factors caused some of the larger monthly variances. For example, Pepco was asked to explain what caused the actual 2011 additions to distribution plant to be $18.4 million less than budgeted and to explain what caused the May 2011 distribution plant additions to be approximately $20 million less than budgeted. In response, Pepco stated:

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1 Response to OPC Data Request 3, Question 21, is provided as Exhibit OPC (B)-11.

2 Response to OPC Data Request 13, Question No. 14 is provided as Exhibit OPC (B)-13.

> Differences between projected and actual plant additions can be due to differences in the timing of the capital spending (projected versus actual) or differences in when the projects actually get cut into plant in service in the financial records of the Company. A detailed analysis of the specific causation of differences in actual vs. projected plant additions has not been performed.

No further information was provided in the response.

Q. DO YOU HAVE THE INFORMATION NEEDED TO PREPARE AN ACTUAL TO BUDGET COMPARISON OF THE NET PLANT ADDITIONS FOR THE FORECAST PERIOD OF THE TEST YEAR ON A DISTRICT OF COLUMBIA DISTRIBUTION BASIS?

A. I do not have the information needed to determine what portion of the actual plant additions provided by Pepco are attributable to its District of Columbia jurisdictional distribution operations. The data provided by Pepco shows that the actual net plant additions on a total Pepco basis were $115.4 million less than budgeted for the forecast period of the test year, and the total Pepco distribution additions were $78.4 million less than budgeted for that same period. However, as Pepco has not provided data in sufficient detail, I am not able to determine precisely how much of these variances are specific to the plant additions incorporated in Pepco's filing on a District of Columbia jurisdictional distribution basis.

Q. IN YOUR OPINION, SHOULD THE PLANT IN SERVICE INCLUDED IN RATE BASE IN PEPCO'S FILING BE REDUCED?

A. Yes. Given the significant variance on a total Pepco basis in the net additions to plant in service for the forecast portion of the test year in this case, it is highly likely that the forecast plant additions incorporated in Pepco's filing on a Distribution of Columbia distribution basis are overstated, perhaps substantially.

Q. ARE YOU ABLE TO PROPOSE AN ADJUSTMENT USING THE DATA THAT ARE AVAILABLE TO YOU AT THIS TIME?

A. Yes. At this time, and based on information that has been provided by Pepco to date, I recommend that the average test year plant in service balance be reduced by $12,737,000 on a District of Columbia jurisdictional basis. As a result of this recommended reduction to plant in service, depreciation expense should be reduced by $313,000 and accumulated depreciation should be reduced by $157,000.

Q. HOW HAVE YOU CALCLUATED YOUR RECOMMENDED REDUCTION TO PLANT IN SERVICE TO ACCOUNT FOR PEPCO'S OVERSTATEMENT OF THE FORECASTED PLANT ADDITIONS?

A. My recommended adjustment is presented in Exhibit OPC (B)-4, Schedule 13. As shown on the schedule, I have reduced the forecast total distribution cost of service net plant additions incorporated in Pepco's filing for each of the forecasted months, April 2011 through September 2011, by 57.5%. As previously mentioned, the total Pepco distribution net plant additions were only 42.5% of the forecasted amount for the April 2011 through September 2011 period. Stated another way, the total Pepco distribution net plant additions for the period April 2011 through September 2011 were over-stated by 57.5% (100% - 42.5%). Thus, I reduced the forecasted total distribution cost of service plant monthly net additions by the 57.5% factor. The resulting impact on the test year average total

Pepco distribution cost of service plant was a reduction of $24,442,541. Based on amounts contained in Pepco's Compliance Filing at Section 206.9, page 7, it was determined that the ratio of District of Columbia distribution-related plant to total Pepco distribution cost of service plant was .4925. The .4925 ratio was applied to the reduction to the test year average total Pepco distribution cost of service plant.

The AMI meters, which are specific to the District of Columbia jurisdiction, are adjusted separately and annualized in Pepco's filing. As such, it was also necessary to remove the impact of the AMI meter addition variances that occurred during the forecast period from the adjustment. This would remove any impacts of the AMI meter program from my recommended reduction to the forecast plant additions in the filing. Application of the .4925 ratio and removal of the impact of the AMI meter additions variances results in an adjustment to reduce the average test year plant in service on a District of Columbia basis of $12,737,000.

The related impacts on depreciation expense and accumulated depreciation were estimated based on the composite depreciation rate incorporated in the filing of 2.46%, resulting in a $313,000 reduction to depreciation expense and a $157,000 reduction to accumulated depreciation.

Q. WHEN DISCUSSING ISSUE 1(B) EARLIER IN THIS TESTIMONY, YOU INDICATED THAT PEPCO MODIFIED ITS CAPITAL BUDGET FOR PURPOSES OF FORECASTING THE APRIL 2011 THROUGH SEPTEMBER 2011 PLANT ADDITIONS. WHY DID PEPCO MODIFY THE BUDGETED AMOUNTS IN PREPARING THE FORECAST PORTION OF THE TEST YEAR IN THIS CASE?

A. According to Pepco's response to Data Request No. 3, Question No. 24[3], the Company's 2011 Capital Budget, which was prepared in the fall of 2010, was used as the basis for preparing the forecasted capital expenditures for the test period. That capital budget included assumptions regarding the forecasted capital expenditures for September through December, 2010. However, Pepco determined that the actual capital expenditures for the months of October 2010 through March 2011 were $50 million less than had been in either its forecast or its budget. Of the $50 million that Pepco was under-budget as of March 2011, Pepco assumed it would make up $29 million of that amount during April through September 2011. In other words, the forecast portion of the test year assumes that: (1) the full amount of capital expenditures originally budgeted to be spent during the months of April 2011 through September 2011 would be expended; and (2) an additional $29 million would be expended to make up for some under spending in October 2010 through March 2011. Given that the actual plant additions for the period April 2011 through September 2011 were, as addressed

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[3] Response to Data Request No. 3, Question No. 24 provided as Exhibit OPC (B)-8.

previously, so far under budget, Pepco's ambitious forecast did not come to fruition.

Q. DID PEPCO PROVIDE INFORMATION CLEARLY SHOWING HOW ITS REVISED CAPITAL BUDGET DISCUSSED ABOVE WAS USED TO DETERMINE THE AMOUNT OF ADDITIONS TO PLANT IN SERVICE INCORPORATED IN RATE BASE IN ITS FILING IN THIS CASE?

A. No, it did not. OPC Data Request 3, Question 24, specifically asked Pepco to provide a discussion and a reconciliation showing, in detail, how the capital budgets it provided in response to discovery were input into its filing and used in determining the projected 13-month average plant in service balances for the test year. The response, which is provided as Exhibit OPC (B)-8, indicates, in part, as follows:

> The actual transfers/additions to EPIS for September 2010 through March 2010 (*sic.*) portion of the test period are based on actual capital expenditures that have accumulated in CWIP over time until the month of project completion. The forecasted transfers/additions to EPIS are based on both actual capital expenditures which have accumulated on uncompleted CWIP projects through March 2011 along with any forecasted expenditures from April 2011 through September 2011 up until the projected completion date. Many of the forecasted additions to EPIS, do contain some actual expenditures that were made through March 2011. The actual and forecasted additions to EPIS are included in the monthly EPIS balances used to determine average EPIS.

Further details regarding how the budgeted capital expenditures were used to derive the forecasted additions to plant in service incorporated in Pepco's rate case filing are contained in the response to OPC Data Request 13, Question 15. The response, which is provided as Exhibit OPC (B)-9, provides a comparison of projected monthly capital expenditures to the monthly plant additions incorporated in Pepco's filing. It also references the electronic workpapers provided in response to OPC DR 1-1. In these workpapers, the projected monthly plant additions are input in total with no detail behind what is being included. Pepco has not shown how its projected plant additions for the period April 2011 through September 2011 were determined in this case. As previously addressed in this testimony, under Issue 2(b), I recommend that Pepco be required to provide much more detailed information concerning the forecast portion of its test year in future cases in which a partial forecast test year is used.

Issue 3(b) – Adjustments to Average Rate Base

Q. DESIGNATED ISSUE 3(B) STATES: "ARE PEPCO'S PROPOSED ADJUSTMENTS TO THE AVERAGE TEST YEAR RATE BASE JUST AND REASONABLE?" WHAT IS YOUR POSITION WITH RESPECT TO THIS ISSUE?

A. As indicated above, OPC is recommending several adjustments to the adjusted rate base included in Pepco's filing. Pepco has proposed an average adjusted rate base of $1,172,025,000. OPC's rate base, giving effect to all of the adjustments OPC has quantified at this time, is $35,715,000 less than that proposed by Pepco, resulting in an OPC recommended rate base of $1,136,310,000.

Exhibit OPC (B)-2, column (A) presents a summary of the individual adjustments to the Company's proposed rate base sponsored by OPC. OPC's total recommended reduction to rate base of $35,715,000 at this time is comprised of the following adjustments:

$12,480,000	Update of Forecast Plant Additions and Retirements to Actual
$ 2,119,000	Reduction to AMI Regulatory Asset – Incremental Costs
$11,135,000	Remove NE Distribution and Substation Plant
$ 1,574,000	Reduction to Cash Working Capital
$ 1,207,000	Remove Proposed Hurricane Irene Regulatory Asset
$ 355,000	Remove Post-Test Year Flotation Costs
$ 713,000	Reduction to Meter Blanket Capital Budget (per OPC Witness Mara)
$ 2,851,000	Reduction to Feeder Undergrounding Capital Budget (per OPC Witness Mara)
$ 209,000	Remove Medicare OPEB Tax Subsidy Adj. (per OPC Witness Bright)
$ 2,343,000	Remove Severance Regulatory Asset (per OPC Witness Bright)
$ 629,000	Reduction to AMI Depreciation (per OPC Witness Binz)

I previously addressed under issue 3(a) the adjustment to the forecast plant additions and plant retirements. I will address each of the remaining individual rate base adjustments which I am sponsoring below and under Issues 3(c), 5, and 9(b) of this testimony.

NE Distribution and Substation Plant

Q. IN ITS SUPPLEMENTAL FILING, PEPCO MADE A NEW ADJUSTMENT TO INCLUDE PROJECTED COSTS ASSOCIATED WITH ADDING A THIRD TRANSFORMER AT ITS NORTHEAST SUBSTATION. WOULD YOU PLEASE DESCRIBE THIS NEW ADJUSTMENT?

A. At pages 5 and 6 of his Supplemental Testimony, Pepco Witness Gausman discusses a new adjustment to the average test year rate base. The new adjustment increases plant in service by $12,464,000 and rate base by $11,135,000 for the projected costs associated with adding a third transformer at the Northeast Substation. Pepco projects the project to be complete and in service in June 2012.

Q. DO YOU AGREE THIS PROJECT SHOULD BE INCLUDED IN THE ADJUSTED TEST YEAR RATE BASE?

A. No. There are several reasons that this project should not be included in the test year rate base. First, even if the project is completed as forecast by Pepco, it should be excluded from rate base because the project is too remote in time and will not be used and useful for the entire rate effective period. The Commission has previously allowed inclusion of certain post-test year plant additions in limited circumstances. Given the projected completion date of the new substation, this project does not qualify for special treatment.

Second, the project costs and timing are too uncertain to be relied upon. According to the response to OPC Data Request 13, Question No. 23(e)[4], the engineering department is still writing the scope of work for the construction contract; thus, a contract has not been awarded.

Additionally, Pepco's response to OPC Data Request 13, Question No. 23(f), indicates that the project will add approximately 70 MVA to its current firm capacity of 72MVA and that this capacity "...will be used to serve load growth on feeders already supplied from Northeast Sub. 212, which will begin to supply a new LVAC network group that will be extended to the North of Massachusetts area in 2012 and a second LVAC group that is currently planned to be extended to

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4 Response to OPC Data Request 13, Question 23, exclusive of attachments, is being provided as Exhibit OPC(B)-14.

the Pennsylvania Avenue Quarter area in 2014." The additional revenue that will be generated from the load growth is not reflected in the test year; thus, allowance of the project in plant in service will result in a mismatch of the components of the revenue requirement calculation.

Q. PLEASE ELABORATE ON YOUR CONCERNS WITH PERMITTING THE INCLUSION OF THIS PROJECT IN THE TEST YEAR RATE BASE.

A. In Order No. 14712, issued in FC 1053, the Commission addressed the allowance of post-test year plant additions as follows:

> On a case-by-case basis, the Commission has allowed the rate base to include the cost of construction work completed outside the test period in certain "unique and compelling" circumstances, including situations where (1) the project's completion date is not too remote in time from the test year; (2) the cost of the project is reasonable; and (3) the project will clearly be beneficial (i.e., "used and useful") to ratepayers during the entire rate effective period.[5]

The addition of the third transformer at the Northeast Substation is projected to be placed in service and used and useful sometime in June 2012. As I stated earlier, this is after the start of the rate effective period; thus, the project does not meet the third criteria. In prior cases in which Pepco has been permitted to include post-test year plant additions in limited circumstances, the projects were in-service prior to the start of the rate effective period.

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[5] Order No. 14712, p. 43.

Q. WHAT ADJUSTMENT NEEDS TO BE MADE TO REMOVE THIS PROJECT FROM THE ADJUSTED TEST YEAR?

A. Pepco's Ratemaking Adjustment 43, which was presented for the first time in the updated filing at PEPCO (2F)-2, page 47, should be rejected. The result of this disallowance on a District of Columbia distribution basis is a $12,464,000 reduction to plant in service, a $153,000 reduction to accumulated depreciation, a $1,176,000 reduction to accumulated deferred taxes and a $307,000 reduction to depreciation expense. This adjustment is reflected on Exhibit OPC (B)-4, Schedule 2.

Issue 3(c) – Cash Working Capital

Q. DESIGNATED ISSUE 3(c) STATES: "IS PEPCO'S PROPOSED CASH WORKING CAPITAL ALLOWANCE REASONABLE?" WHAT IS YOUR POSITION WITH RESPECT TO THIS ISSUE?

A. I recommend that the cash working capital proposed by Pepco of $14,333,000 be reduced by $1,574,000 to $12,759,000. My recommended revision is the result of two modifications to the cash working capital calculations provided in Pepco (2F)-2, at page 51 of 52.

Q. WHAT IS THE FIRST MODIFICATION YOU RECOMMEND?

A. The first modification is to revise the Federal income taxes included in Pepco's cash working capital analysis. In its cash working capital calculation, Pepco included test year Federal income taxes of ($12,739,169). The inclusion of a negative amount for Federal income taxes results in an increase in the cash working capital amount. This is because the lag days for Federal income taxes exceed the revenue lag days in Pepco's lead lag study. Thus, under normal circumstances, inclusion of Federal income taxes in the calculation has the effect of reducing the cash working capital requirements. However, by inputting a negative balance for Federal income taxes it has the opposite effect, increasing the working capital requirements.

In its filing, Pepco has included a positive amount for Federal income taxes in the revenue requirements for both the unadjusted and the adjusted test year. It is not appropriate to assume negative income taxes in the cash working capital analysis, yet charge ratepayers for federal income taxes in rates. I recommend that the ($12,739,169) included by Pepco for Federal income taxes in its cash working capital analysis be replaced by its adjusted test year Federal income tax expense reflected on PEPCO(2F)-2, page 1, of $17,493,000.

Q. WHAT IS THE SECOND MODIFICATION?

A. The lag days incorporated in Pepco's cash working capital calculation are based on a 2005 study. As part of this case, Pepco is annualizing the AMI project in rates as though it were used and useful throughout the test period. The implementation of the AMI system will result in a reduction to the revenue lag as the meter reading function will be fully automated. In response to PSC Data Request 3, Question No. 33[6], Pepco agreed that "The installation and full deployment of AMI meters could potentially impact revenue lags." The response also indicates that the impacts cannot be measured or accurately estimated until the AMI is fully deployed, and that a new lead lag study will be preformed based on a full year of post-deployment data. Since the AMI system is being included in the adjusted test year as though fully installed and deployed, an estimate of the impact of such deployment on cash working capital requirements should also be reflected. Since Pepco failed to provide the requested impact of the implementation of the AMI on cash working capital, I recommend that the revenue lag be reduced by two days, from 52.66 days to 50.66 days. The revenue lag in Pepco's 2005 lead-lag study assumed that the amount of lag days between reading the meter and billing customers would be 4.31 days. Absent better data having been provided by Pepco, it is reasonable to assume that the implementation of the AMI will reduce this 4.31 day lag by two days.

Q. WHAT ADJUSTMENT RESULTS FROM YOUR RECOMMENDED MODIFICATIONS TO THE CASH WORKING CAPITAL CALCULATION?

A. As shown on Exhibit OPC (B)-4, Schedule 3, cash working capital should be reduced by $1,574,000. The calculations remain unchanged from that presented by Pepco, with the exception of my two recommended modifications.

Q. DO YOU HAVE ADDITIONAL RECOMMENDATIONS WITH REGARDS TO CASH WORKING CAPITAL?

A. Yes. The lead-lag study relied on by Pepco in support of its cash working capital request was conducted in 2005. Given the staleness of the data used, I recommend that the Commission require Pepco to conduct a new lead-lag analysis in its next rate case. Pepco has indicated in response to PSC Data

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[6] PSC Data Request 3, Question No. 33, is being provided as Exhibit OPC (B)-15.

Request No. 3, Question 33, that it will conduct a new lead lag study once the AMI meters are fully deployed based on a full year of post-deployment data, so Pepco should be agreeable to this request. If a full year of deployment has not occurred prior to the next rate case, then an estimate of the impacts of full deployment should be incorporated in the study. Absent a new lead-lag study, no cash working capital allowance should be granted in the next rate case.

Issue 4 – Revenues

Q. PLEASE ADDRESS ISSUE 4, WHICH ASKS "ARE PEPCO'S TEST YEAR SALES AND REVENUES JUST AND REASONABLE?"

A. The OPC does not challenge the test year sales and revenues incorporated in Pepco's filing at this time.

Q. ISSUE 4(A) ASKS: "HAS PEPCO PROPERLY WEATHER-NORMALIZED ITS SALES AND REVENUES?" DO YOU TAKE ISSUE WITH THE WEATHER NORMALIZED SALES AND REVENUES IN PEPCO'S FILING?

A. No, I do not take issue with Pepco's weather normalized sales and revenues at this time.

Issue 5 – Test Year Operating Expenses

Q. PLEASE ADDRESS ISSUE 5, WHICH STATES "ARE PEPCO'S TEST YEAR OPERATING EXPENSES JUST AND REASONABLE?"

A. OPC is recommending several adjustments to the Company's proposed adjusted test year operating expenses. OPC's proposed adjustments include changes to operation and maintenance expense, depreciation expense, and amortization expense. Additionally, each of the OPC's adjustments to revenue and expense items also impact D.C. income taxes and federal income taxes. Exhibit OPC (B) -2 presents a summary of the individual adjustments to the Company's test year expenses recommended by OPC. Adjustments to test year expenses include the following:

$ 420,000	Employee Health & Welfare Expense Adjustment
$ 849,000	Adjustment to Storm Damage and Hurricane Irene Costs
$ 314,000	Removal of Non-Recurring Meter Expense
$ 44,000	Removal of Accounts Receivable Write-off
$ 404,000	Remove Post-Test Year Flotation Costs
$ 313,000	Depreciation Impact of Plant Update Adjustment
$ 268,000	Amortization of AMI Regulatory Asset
$ 307,000	Depreciation Impact of Removal of NE Distribution & Substation Plant
$ 94,000	Reduction to Incremental Customer Care Expense (Mara)
$ 49,000	Depreciation Impact of Meter Blanket Plant Adj. (Mara)
$ 71,000	Deprec. Impact of Feeder Undergrounding Adj. (Mara)
$ 145,000	Remove Medicare OPEB Tax Subsidy Amortization (per OPC Witness Bright)
$ 1,657,000	Remove Amortization of Severance Regulatory Asset (per OPC Witness Bright)
$ 1,078,000	Reduction to AMI Depreciation (per OPC Witness Binz)

I address below each of the individual expense adjustments that I am sponsoring. OPC Witnesses Ron Binz, Nancy Bright and Kevin Mara will also be sponsoring and explaining specific expense adjustments in their respective testimonies.

Q. WHICH OF THE EXPENSE ADJUSTMENTS IDENTIFIED ABOVE DO YOU SPONSOR?

A. I am sponsoring the adjustments to employee health and welfare expense, storm costs and Hurricane Irene costs, non-recurring meter expense, accounts receivable write-off, and flotation costs. The adjustments to depreciation expense and amortization expense I am sponsoring are addressed elsewhere in this testimony.

Additionally, I have quantified the impact on depreciation expense associated with Kevin Mara's recommended plant adjustments on Schedules 10 and 11 of Exhibit OPC (B)-4. I also quantified the impact on depreciation expense associated with Ron Binz's recommendation regarding the depreciation rate that should be applied to the AMI meters on Exhibit OPC (B)-4, Schedule 14. I will address each of the expense adjustments individually below.

Employee Benefits Expense

Q. DID YOU REVIEW THE ADJUSTMENT TO EMPLOYEE BENEFIT EXPENSE CONTAINED IN PEPCO'S FILING?

A. Yes. The employee benefit expense included in the test year is based on six months of actual data and six months of budgeted data. In PEPCO (F)-1, Ratemaking Adjustment 23, the Company has proposed a $1,113,000 increase in test year total Company employee health and welfare costs included in O&M expense. The proposed increase consists of: (1) an 8% escalation of the projected test year medical costs ($1,038,000); (2) a 5% escalation of projected test year dental costs ($55,000); and (3) a 5% escalation of projected test year vision costs ($20,000). After allocation to distribution and to the District of Columbia, the proposed increase of $1,113,000 comes to $379,000 on a D.C. distribution basis. These are for projected increases that would occur in the post-test year period.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THESE AMOUNTS?

A. Yes. I recommend that the medical, dental and vision costs for the forecasted portion of the test year be revised to reflect actual amounts where available. I also recommend that the Company's proposed post-test year increase in employee benefit costs be removed.

Q. WHY DO YOU RECOMMEND THAT THE TEST YEAR COSTS BE MODIFIED?

A. As previously mentioned, the test year medical, dental and vision costs are based on six months of actual data and six months of projected data. In response to OPC Data Request 1, Question No. 96,[7] Pepco provided an update to its workpaper supporting the test year expense, replacing budgeted amounts for April 2011 through June 2011 with actual balances. The table below provides a comparison of the actual costs incurred through June 2011 combined with the projected costs for July 2011 through September 2011 with the amounts contained in the filing:

	Updated Test Year Amount	Test Year Per Filing	Difference
Medical Cost	$12,815,577	$ 12,979,116	$ (163,539)
Dental Cost	1,122,234	1,096,763	25,471
Vision Cost	412,219	394,904	17,315
Total	$14,350,030	$ 14,470,783	$ (120,753)

As the above table shows, updating the test year to reflect nine months of actual costs and three months of budgeted costs results in a $120,753 reduction to the employee health and welfare costs on a total Company basis.

7 Response to OPC Data Request 1, Question No. 96 is provided as Exhibit OPC (B)-16.

Q. WHY SHOULD THE COMPANY'S PROPOSED ESCALATION OF THE TEST YEAR EMPLOYEE BENEFIT COSTS BE REDUCED?

A. The escalation factors proposed by the Company ignore changes in its employee benefit plans that would offset potential cost increases. As a result, the escalation factors are neither specific to nor appropriately applied to the Company.

Q. HOW WERE THE ESCALATION FACTORS USED IN PROJECTING THE POST-TEST YEAR INCREASE IN EMPLOYEE BENEFIT COSTS SELECTED BY THE COMPANY?

A. According to the Company's response to OPC Data Request 1, question 99[8], a medical trend study from Lakes Consulting, Inc. was used "as guidance" in determining the inflation factors for estimating the 8% medical cost increase and the 5% dental and vision increases. The Company provided a copy of the medical trend survey conducted by Lakes Consulting, Inc. for the first quarter of 2011. The survey provided indicates that it "represents the projected trends in use for the first quarter of 2011."

The information provided shows that the projected trends were based on a survey of six companies in the region, which consisted of the Virginia, Maryland and D.C. area. The escalation factors used in the Company's filing for projected post-test year cost increases fall within the range presented in the survey for projected 2011 cost increases.

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[8] Response to OPC Data Request 1, Question No. 99 is provided as Exhibit OPC (B)-17.

Q. ARE THERE ANY PROBLEMS, IN YOUR OPINION, WITH USING THIS SURVEY AS SUPPORT FOR THE ESCALATION INCREASES REFLECTED IN THE COMPANY'S FILING?

A. Yes. First, the medical trends presented in the survey are for the first quarter of 2011, and are not specific to the 2012 period during which Pepco's new rates will be in effect. Second, and more important, the trends in this tri-regional report do not account for changes made by Pepco to control its benefit costs.

Q. PLEASE EXPLAIN.

A. According to the response to OPC Data Request 1, Question 98[9], the Company is increasing the amount of co-pay for office visits and the amount of deductibles for one of its benefit plans, the PPO Medical Plan, effective January 1, 2012. Additionally, according to the response to OPC Data Request 3, Question 12[10], the Company is increasing the portion of medical costs that will be paid by employees, effective January 1, 2012. Management's cost share will increase from 19% to 20% effective January 1, 2012. The cost share percentage that will be paid by Local Union 1900 employees will increase from 16.7% for the PHI PPO plan and 14.7% for the PHI HMO plan to 20% for both plans. This is a fairly substantial increase in the portion of the plan costs that will now be paid by the union employees. The Company's filing does not reflect the effects of these known changes in deductibles and co-pays and the acknowledged increase in the portion of employee cost sharing that takes effect January 1, 2012. Consequently,

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9 Response to OPC Data Request 1, Question No. 98 is provided as Exhibit OPC (B)-18.

10 Response to OPC Data Request 3, Question No. 12 is provided as Exhibit OPC (B)-19.

I recommend that the projected post-test year medical, dental and vision cost increases of 8%, 5% and 5% respectively be rejected. The amount should be limited to the test year cost level, modified to reflect the update for actual information where known.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO PEPCO'S PROPOSED EMPLOYEE HEALTH AND WELFARE COSTS?

A. As shown on Exhibit OPC (B)-4, Schedule 4, the Company's proposed medical, dental and vision costs should be reduced by $420,000 on a District of Columbia distribution basis. The Company has not supported an increase above the level recorded in the test period, particularly once the known increases in the employees' share of the costs are taken into account.

<u>Storm Damage Costs & Hurricane Irene Costs</u>

Q. DID PEPCO ADJUST THE AMOUNT OF STORM DAMAGE RESTORATION COSTS INCURRED IN THE TEST YEAR?

A. Yes. In PEPCO (F)-1, Adjustment No. 26, the Company reduced its forecasted test year storm damage costs included in distribution O&M expense by $765,000 to reflect a three-year average of such costs based on (a) the actual amounts recorded during the years ended September 30, 2009 and September 30, 2010 and (b) the combined actual and forecasted amounts for the test year ended September 30, 2011. Thus, the Company's adjustment is based on an average of both actual and forecasted amounts.

Q. IS IT APPROPRIATE TO REFLECT STORM DAMAGE COSTS BASED ON AN HISTORIC AVERAGE COST LEVEL?

A. Yes. In situations in which costs fluctuate from year to year it is appropriate to adjust the test year cost level to an historic average level so that costs factored into rates are based on a normalized cost level. Storm damage costs are a prime example of costs that fluctuate from year to year. The table below shows the actual storm restoration cost reflected in distribution related O&M expense on Pepco's books for the period January 1, 2006 through September 30, 2010:

(Thousands)	Total System	DC Amount
12 months ended 12/31/06	$ 5,857	$ 2,157
12 months ended 12/31/07	$ 3,626	$ 1,335
12 months ended 9/30/08	$ 3,794	$ 1,397
12 months ended 9/30/09	$ 2,443	$ 926
12 months ended 9/30/10	$ 23,309	$ 4,140

Q. HOW HAS THE COMMISSION PREVIOUSLY ADDRESSED THE NORMALIZATION OF STORM DAMAGE COSTS?

A. In F.C. 1053, Pepco made an adjustment to normalize storm damage costs based on a three-year average cost level. In Order No. 14712, at page 75, the Commission approved Pepco's adjustment, indicating that parties either supported the adjustment or did not oppose it. In F.C. 1076, Order 15710, at page 43, the Commission approved Pepco's proposed three-year average normalization methodology.

Q. YOU PREVIOUSLY INDICATED THAT PEPCO'S NORMALIZATION OF STORM DAMAGE COSTS IN THIS CASE IS BASED ON BOTH ACTUAL AND FORECASTED COSTS. DO YOU AGREE WITH THIS APPROACH?

A. No, I do not agree that the cost should be normalized based on a combination of actual historic costs and forecasted costs. Since the time Pepco filed its case, additional actual cost data have been made available. Any normalization of costs that fluctuate from year to year should be based on actual amounts and exclude forecasts.

Q. DO YOU RECOMMEND THAT AN AVERAGE NORMALIZATION APPROACH, USING ALL ACTUAL DATA, BE ADOPTED IN THIS CASE?

A. Yes, it is appropriate to base the storm damage costs to be incorporated in base rates on a normalized methodology using actual data. However, I recommend that a longer period of time than the three-year period proposed by Pepco be used in this case to normalize the costs to incorporate in base rates. The purpose of using an average is to set a reasonable estimate of the cost level that is likely to be experienced during the rate effective period. Since the frequency and magnitude of storm events can vary significantly from year to year, using an average historic cost level can result in a reasonable, normalized estimate. However, during two of the three most recent years there have been several significant storms that have had a larger impacting on Pepco's distribution-related storm restoration costs than had been the case in prior years. The table presented above demonstrates that the storm costs incurred by Pepco in the twelve month period ended September 30, 2010 were significantly higher than the costs incurred during the prior four years, on both a total distribution system basis and on a District of Columbia basis. Additionally, the actual distribution-related storm restoration costs experienced by Pepco were also significantly higher during the test year in this case, or the twelve months ended September 30, 2011, as a result of a snowstorm that occurred on January 26, 2011 and the impacts of Hurricane Irene.

Q. WHAT PERIOD DO YOU RECOMMEND FOR NORMALIZING THE STORM COSTS TO INCLUDE IN BASE RATES?

A. I recommend that a six year period be used based on the most recent information available. On Exhibit OPC (B)-4, Schedule 5, page 1, I present the actual storm costs reflected in distribution related O&M expense for the twelve month periods ending December 31, 2006 and 2007 and the twelve month periods ending September 30, 2008 through September 30, 2011. I did not have information for the twelve months ending in September for years prior to 2008, so I included data for the twelve month periods ended December 31 for the years 2006 and 2007. As shown on the schedule, the result is an average storm damage cost for District of Columbia distribution-related O&M expense using a six-year period of $2,787,000. This approach is more likely to result in a normalized level of costs as it helps to smooth out the large impact of the high level of storm costs incurred by Pepco over the last two years. If the costs were based on a three-year average, as proposed by Pepco, updated for actual costs for the most recent year, the impact of two abnormally high storm cost years would greatly and unfairly skew the average.

Q. HOW DOES THE NORMALIZED AMOUNT YOU RECOMMEND IN THIS CASE OF $2,787,000 COMPARE TO THE AMOUNT APPROVED IN THE PRIOR PEPCO RATE CASE, F.C. 1076?

A. In the prior case, the amount included in rates was based on a 3-year average storm damage costs on a total distribution-related O&M expense basis of $4,481,000. After application of the 0.3683 allocation factor used in that case, the amount on a District of Columbia distribution basis was $1.65 million. The amount I am recommending to include in this case of $2.787 million is approximately $1.14 million higher than the amount allowed in the prior Pepco rate case. This increase is due to the impact of the escalating level of storm restoration costs during the past two years and their effect on the determination of average costs. If Pepco's three-year average approach is approved, the variance between the levels adopted in this case and the previous rate case would be even greater.

Q. IN THE SUPPLEMENTAL DIRECT TESTIMONY OF PEPCO WITNESS LINDA J. HOOK, PEPCO HAS UPDATED ITS FILING TO INCLUDE A REGULATORY ASSET FOR COSTS RESULTING FROM HURRICANE IRENE, AS WELL AS THE AMORTIZATION THEREOF. DO YOU AGREE THAT THIS UPDATE SHOULD BE ALLOWED?

A. No, I do not. According to Ms. Hook's supplemental testimony, the Company is requesting recovery, over a three-year period, of the estimated $2.1 million (on a

District of Columbia jurisdictional basis) in costs associated with Hurricane Irene restoration efforts. The Company also proposes that the unamortized balance earn a return through rate base treatment. In response to OPC Data Request 13, Question No. 9[11], the Company indicated that the $2,159,000 amount reflected in its updated filing contained a spreadsheet error and that the correct amount is $2,336,872.

Instead of establishing a regulatory asset for the estimated restoration costs, the costs incurred for Hurricane Irene restoration should be included in determining the normalized storm restoration cost level. On Exhibit OPC (B)-4, Schedule 5, I have calculated a normalized cost level of storm restoration expense that includes the actual and projected District of Columbia jurisdictional costs associated with the Hurricane Irene restoration (as corrected by Pepco in response to discovery), for the year ended September 30, 2011. While Hurricane Irene was a significant storm event, it does not rise to the level of warranting special regulatory asset treatment and recovery. In fact, based on Pepco's response to OPC Data Request 13, Question No. 9, the vast majority of the Hurricane Irene restoration costs were incurred in the Maryland jurisdiction. The response shows total projected restoration costs booked to O&M expense of $13.86 million, with $11.52 million, or 83%, of that amount associated with the Company's Maryland operations.

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11 Response to OPC Data Request 13, Question No. 9 is provided as Exhibit OPC (B)-20.

Q. **IN DETERMINING YOUR RECOMMENDED NORMALIZED STORM RESTORATION COSTS TO INCLUDE IN BASE DISTRIBUTION RATES ON EXHIBIT OPC (B)-4, SCHEDULE 5, YOU IDENTIFY THE AMOUNTS FOR THE 12-MONTHS ENDED SEPTEMBER 30, 2011 AS "CORRECTED AND ADJUSTED". WOULD YOU PLEASE EXPLAIN WHAT WAS CORRECTED AND ADJUSTED?**

A. The calculation of the corrected and adjusted amount for the twelve month period ended September 31, 2011 is presented on page 2 of the schedule. The amount presented by the Company in its filing for the twelve months ending September 31, 2011 was based on a combination of actual and forecasted amounts. I adjusted the amount so that it would be based on actual storm restoration costs incurred by Pepco during the test year. I further adjusted the amount to remove the actual Hurricane Irene restoration costs included in the total costs as I did not have the split of the actual amounts recorded during that period between Maryland and the District of Columbia. I then added back in the Company's corrected estimate of the Hurricane Irene restoration costs that are specific to the District of Columbia distribution operations of $2,337,000. Including the full $2,337,000 would allow for higher costs to be included associated with Hurricane Irene on a District of Columba basis than what was actually realized and recorded during the test year; however, I agree it is reasonable to include the full impact of Hurricane Irene in determining the normalized storm costs to include in rates in this case.

On page 2 of the Schedule, at line 1, I also corrected the allocation factor used by the Company for the amount of costs associated with the January 26, 2011 snowstorm event that was assigned to the District of Columbia. In the Company's Ratemaking Adjustment 26 in its filing, it applied an allocator of 8% to the costs incurred for the January 26, 2011 snowstorm for purposes of determining the $827,000 amount attributable to the District of Columbia. However, based on Pepco's workpapers provided in Section 206.9 of the Compliance Filing, at page 247, the correct amount on a District of Columbia distribution O&M expense basis associated with that storm is $1,239,915, with an allocation of 12%. Since this falls in the portion of the test year that includes actual costs, I corrected this apparent error in determining the cost on a District of Columbia distribution basis. After the adjustments and corrections, the resulting District of Columbia distribution-related storm damage expense for the year ended September 30, 2011 is $6,770,000. I included this amount on page 1 of the schedule in calculating the average storm restoration costs.

Q. WHAT ADJUSTMENTS NEED TO BE MADE TO PEPCO'S UPDATED FILING TO REFLECT YOUR RECOMMENDED LEVEL OF NORMALIZED STORM RESTORATION COSTS?

A. As shown on Exhibit OPC (B)-4, Schedule 5, page 1, test year expenses should be reduced by $849,000. This adjustment both reflects my recommended level of normalized storm restoration expenses of $2,787,000 and removes the Company's proposed Hurricane Irene regulatory asset and the amortization thereof.

Additionally, I have removed the Company's proposed Hurricane Irene regulatory asset of $1,207,000 from test year rate base on the schedule.

Remove Non-Recurring and Out-of-Period Expenses

Q. ARE THERE ANY NON-RECURRING COSTS INCLUDED IN THE "ACTUAL" PORTION OF THE TEST YEAR THAT SHOULD BE REMOVED?

A. Yes. I am recommending two separate adjustments to remove non-recurring and out-of-period costs from the test year in this case. Meter Expense should be reduced to remove a non-recurring write-off of meter costs that was recorded in December 2010. Additionally, Miscellaneous General Expenses should be reduced to remove a write-off of prior period costs that was recorded in December 2010.

Q. PLEASE DISCUSS THE WRITE-OFF OF METER COSTS.

A. In reviewing the actual and projected monthly operation and maintenance expenses by FERC account, it was evident that the expenses recorded in Account 586 – Meter Expense was significantly higher in December 2010 than the cost recorded in any other month for the period October 2009 through March 2011 and as projected for the forecast portion of the test year. Given the large variance in a single month, Pepco was asked to provide a detailed itemization of the costs exceeding $20,000 recorded in Account 586 in December 2010 and to explain what caused the amount to be so much higher than in the other months presented in Pepco's compliance filing. The response to OPC Data Request 3, Question

20,[12] showed that $753,080 was recorded in December 2010 for "Expense of Pepco labor and other costs associated with review of meter shop capital charges." The response also indicated that the costs were higher in December 2010 "...because there was a $750K expense of capital costs after a review of the meter shop capital order costs determined that there were no new purchases of meters and costs should be expensed."

Given the lack of detail provided in the response regarding the $753,080 charge, additional information was sought in OPC Data Request 13, Question No. 18, the response to which is being provided as Exhibit OPC (B)-23, attached to this testimony. The response agreed that the journal entry recording the $750,080 was a one-time cost associated with costs that were determined to be incorrectly charged and subsequently expensed. The journal entry provided with the response indicates that the charge was for a "write-off of meter costs." Details provided with the response also shows that it was associated with charges incurred from August 2010 through December 2010, part of which pre-dates the test year in this case. As shown, the meter cost write-off is a one-time expense and should be removed from the test year.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO REMOVE THIS NON-RECURRING, ONE-TIME COST FROM THE TEST YEAR?

A. Test year expenses in Account 586 – Meter expense should be reduced by $753,080. The application of the average allocation to the District of Columbia for distribution expenses of 0.4176 results in a reduction to District of Columbia

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[12] Response to OPC Data Request 3, Question No. 20, provided as Exhibit OPC (B)-22.

O&M expense of $314,000. This adjustment is presented on Exhibit OPC (B)-4, Schedule 6.

Q. WOULD YOU PLEASE DISCUSS THE PRIOR PERIOD COSTS RECORDED AS MISCELLANEOUS GENERAL EXPENSE DURING THE TEST YEAR?

A. Yes. In December 2010, Pepco recorded $115,617 to Account 930.2 – Miscellaneous General Expense which it identified in response to OPC Data Request 3, Question 20 as "Expense of A/R balance." OPC Data Request No. 13, Question 20, sought additional information regarding this charge. According to the response, which is being provided with this testimony as Exhibit OPC (B)-24, the charge is for the write-off to expense for a portion of the balance in Account 143100 – Accounts Receivable-Employee Reimbursements. Account 143100 is used to record employee reimbursements receivable when an employee owes the Company funds from a paycheck. The response indicated that during the account reconciliation process, Pepco determined that there was an incorrect posting to the account from the payroll system that had been adjusted in a prior year. Clearly this is both an out-of-period and a non-recurring cost that should be removed from test year expense. The removal of this cost is presented in Exhibit OPC (B)-4, Schedule 7, and results in a $44,000 reduction to expense on a District of Columbia distribution basis.

Removal of Post-Test Year Flotation Costs

Q. PLEASE DISCUSS PEPCO'S ADJUSTMENT FOR POST-TEST YEAR FLOTATION COSTS.

A. Pepco Witness Hook made an adjustment to include flotation costs for a projected 2012 common stock issuance. The projected costs were based on a November 2008 stock issuance, which was approved for recovery in FC 1076 over a two year period. The adjustment is based on projected total 2012 stock issuance costs assigned to Pepco of $1,932,000 with $808,000 allocated to District of Columbia distribution. The adjustment assumes a two-year amortization period with the average unamortized costs reflected in rate base, resulting in a $355,000 adjustment to rate base and a $404,000 adjustment to amortization expense.

Q. IS IT APPROPRIATE TO INCLUDE THE 2012 STOCK ISSUANCE COSTS IN THE ADJUSTED TEST YEAR IN THIS CASE?

A. No, it is not. The adjustment is clearly outside of the test year. In response to OPC Data Request No. 13, Question No. 6[13], Pepco indicated that it does not yet know when in 2012 the next common stock issuance will occur or the amount of stock that will be issued in 2012. In fact, Pepco explains that a resolution concerning the 2012 stock issuance will not be submitted to the Board for approval until the details of the issuance are known. The response also indicated that the additional common stock that will be issued in 2012 has not been considered in the capital structure in this case. Clearly, the amount of flotation

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[13] Response to OPC Data Request 13, Question No. 6 is provided as Exhibit OPC (B)-23.

costs associated with the referenced 2012 stock issuance is not known or measurable and is well beyond the test year in this case.

Q. HAS THE COMMISSION ALLOWED RECOVERY OF FLOTATION COSTS IN RATES IN PRIOR CASES?

A. In her direct testimony, at page 29, Ms. Hook indicates that the Commission approved the inclusion of flotation costs for recovery in rates over a two year amortization period in its Order on Reconsideration in F.C. 1076, Order No. 15864. However, the flotation costs included in the prior rate case were incurred in November 2008, which fell within the historic test year ended December 31, 2008 in that case. Unlike this case, the allowed flotation costs and associated amortization in F.C. 1076 were based on actual, known costs incurred during the test year.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE PROJECTED 2012 FLOTATION COSTS FROM THE TEST YEAR?

A. Pepco's Ratemaking Adjustment 39 needs to be reversed. Rate base should be reduced by $355,000 to remove the proposed unamortized balance net of the accumulated deferred tax impact, and amortization expense should be reduced by $404,000. This adjustment is reflected on Exhibit OPC (B)-4, Schedule 8.

Issue 6 – Depreciation Adjustments

Q. DESIGNATED ISSUE 6 ASKS: "ARE PEPCO'S DEPRECIATION ADJUSTMENTS REASONABLE?" WOULD YOU PLEASE COMMENT ON THIS ISSUE?

A. As best I can tell from Pepco's filing and associated workpapers, the adjustments to depreciation expense contained in Pepco's filing are fall-out issues that result from adjustments being made to plant with one exception pertaining to the depreciation of AMI meters. Pepco states that the depreciation incorporated in the filing, with the exception of depreciation of AMI meters, is based on the depreciation rates approved by the Commission in F.C. 1076. Thus, at this point, I do not take issue with Pepco's depreciation adjustments. OPC Witness Ron Binz addresses the appropriate depreciation rate for the AMI meters. I have recommended several adjustments to the test year plant in service which impact depreciation expense, and Mr. Binz's recommendation regarding the depreciation of AMI meters also impacts depreciation expense.

Q. WOULD YOU PLEASE DISCUSS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENTS TO PLANT IN SERVICE ON DEPRECIATION EXPENSE?

A. Yes. My recommended disallowance of Pepco's attempt to include a third transformer at the Northeast substation in the adjusted test year results in a $307,000 reduction to depreciation expense. Additionally, OPC Witness Mara's recommended reduction to meter blanket capital additions results in a $49,000 reduction to depreciation expense and his recommended reduction to underground feeders results in a $71,000 reduction to depreciation expense. The calculation of these two adjustments is presented in Exhibit OPC (B)-4, Schedules 10 and 11. As previously mentioned in this testimony under Issue 3(a), the plant additions incorporated in the forecast portion of the test year should be reduced to conform to the actual additions made during that period. This results in a $313,000 reduction to test year depreciation expense. I address the impact of Mr. Binz's recommendation regarding the depreciation of AMI meters under issue 9(c).

<u>Issue 9 – Advanced Metering Infrastructure</u>

Q. ISSUE 9 ASKS: "ARE PEPCO'S COSTS FOR THE DEPLOYMENT OF ADVANCED METERING INFRASTRUCTURE ("AMI") REASONABLE?" ARE YOU RECOMMENDING ANY ADJUSTMENTS ASSOCIATED WITH PEPCO'S DEPLOYMENT OF THE AMI?

A. While this issue is being addressed by OPC Witness Kevin Mara, I am recommending an adjustment associated with the incremental costs deferred by Pepco since 2008. In Ratemaking Adjustment 6, Pepco amortizes several categories of deferred AMI costs over a fifteen year period, which is the proposed depreciation period associated with the AMI meters. One of the components of the deferred AMI costs incorporated in the adjustment is for the recovery of the incremental costs associated with AMI implementation since 2008. These are costs that are not being capitalized as part of the AMI asset, such as project management costs, design and consulting services in the development of the AMI system, and incremental increases in operation and maintenance costs associated with various information technology systems. The regulatory asset included in

Pepco's filing for the incremental costs totals $6,412,000 prior to the accumulation of carrying costs and $6,599,000 inclusive of carrying costs. The incremental costs included in the regulatory asset are significantly overstated; thus, I am recommending a reduction to the regulatory asset and the resulting amortization thereof.

Q. ARE THE INCREMENTAL POST-2008 AMI COSTS INCORPORATED IN PEPCO'S REQUESTED REGULATORY ASSET BASED SOLEY ON ACTUAL COSTS INCURRED BY PEPCO?

A. No. Pepco's request is based on actual costs for the period January 2009 through March 2011 and projected costs for the period April 2011 through March 2012. The projected costs incorporated in Pepco's request are significantly overstated and need to be reduced.

Q. PLEASE EXPLAIN.

A. Pepco's projected costs for the period April 2011 through March 2012 were provided in its Compliance Filing, Section 206.9, at pages 147 and 151. In response to OPC Data Request 14, Question 5[14], Pepco provided the actual monthly costs incurred for the period March 2011 through October 2011. A comparison of the actual costs incurred to the projected amount incorporated in Pepco's filing is presented below:

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[14] Response to OPC Data Request 14, Question 5 is being provided as Exhibit OPC (B)-25.

Month	Actual Costs	Projection In Filing	Difference
April 2011	$ 71,705	$ 392,358	$ (320,653)
May 2011	152,368	403,827	(251,459)
June 2011	85,826	476,175	(390,349)
July 2011	65,793	552,955	(487,162)
August 2011	218,698	566,418	(347,720)
September 2011	90,863	550,460	(459,597)
October 2011	160,139	480,941	(320,802)
Total	$ 845,392	$ 3,423,134	$ (2,577,742)

As shown in the above table, Pepco forecasted or budgeted $3,423,134 in incremental expenses associated with the AMI project for the seven month period ended October 2011. The actual costs incurred during that same period was $845,392, which is $2.58 million less than Pepco forecasted. As shown on Exhibit OPC (B)-4, Schedule 1, page 3 of 3, the actual expenditures for the seven month period was 24.7% of the forecasted amount.

For the remaining period, November 2011 through March 2012, Pepco has forecasted or budgeted for $1,807,267 of additional incremental expenses associated with the AMI project and deployment.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. As shown on Exhibit OPC (B)-4, Schedule 1, page 1 of 3, I recommend reducing the total projected incremental post-2008 costs to be deferred from the $6,412,000 proposed by Pepco to $2,473,000. This is based on replacing the budgeted costs for the period March 2011 through October 2011 with the actual costs incurred. The adjustment also reduces Pepco's forecasted costs to be incurred for the period November 2011 through March 2012 to 24.7% of the forecasted level based on the level of actual to budgeted costs for the period March 2011 to October 2011. The calculation is presented on Schedule 1, page 3 of 3.

As shown on page 1 of Exhibit OPC (B)-4, Schedule 1, the incremental costs regulatory asset included in Pepco's proposed rate base should be reduced by $3,887,000, accumulated deferred taxes should be reduced by $1,634,000 and amortization expense should be reduced by $268,000.

<u>Issue 9(b) – Accounting Treatment Old Meters</u>

Q. WOULD YOU PLEASE DISCUSS DESIGNATED ISSUE 9(B)?

A. Designated Issue 9(b) asks: "Is the accounting treatment of old meters reasonable?" According to Pepco Witness Hook, when AMI meters are installed, the non-AMI meters are retired. The retirement results in a loss associated with the net book value of the non-AMI meters as they are being retired at a point when these meters are not fully depreciated on Pepco's books. The loss is reclassified as a regulatory asset on the Company's balance sheet. In its filing, under Ratemaking Adjustment 6, Pepco is amortizing the regulatory asset associated with the loss on the early retirement of the meters, as well as the associated carrying costs, over a period of 15 years, which is the depreciation life being used by Pepco for the new AMI meters. Thus, under Pepco's proposal, the loss on the early retirement of the old meters and associated carrying costs would be recovered over the period that the new AMI meters are being depreciated. In determining the amount of early retirement loss, Pepco has also factored in the amount of depreciation currently being recovered in rates associated with the retired meters, thereby offsetting the regulatory asset balance.

Q. DID PEPCO HAVE AUTHORITY TO ESTABLISH A REGULATORY ASSET FOR THE LOSS ON THE EARLY RETIREMENT OF THE METERS THAT ARE BEING REPLACED BY THE AMI METERS?

A. Yes. D.C. Code § 34-1562 provides authorization of AMI implementation and cost recovery. Specifically, §34-1562(b) states as follows:

> The electric company may establish a regulatory asset for the costs, net of the amount of the ARRA funds received, including depreciation and amortization expense, incurred by the electric company between base rate cases for the implementation of Advanced Metering Infrastructure, including, the amortization expense of the Meter Data Management System, the depreciation expense on the AMI meters, <u>and the undepreciated net book costs of the meters replaced by the AMI meters</u>.
>
> The regulatory asset shall accrue a return at the electric company's authorized rate of return on the balance in the regulatory asset. (emphasis added)

Pepco's inclusion of recovery of the loss on the early retirement of the meters being replaced by the AMI meters in its Ratemaking Adjustment 6 is in compliance with this provision.

Q. DO YOU TAKE ISSUE WITH THE AMOUNT OF LOSS ON THE EARLY RETIREMENT OF THE METERS THAT HAS BEEN CALCULATED BY PEPCO AND INCLUDED IN ITS RATEMAKING ADJUSTMENT 6?

A. No, I do not.

<u>Issue 9(c) – Depreciation of AMI Meters and Costs</u>

Q. WOULD YOU PLEASE DISCUSS ISSUE 9(C)?

A. Designated Issue 9(c) asks: "Is the proposed length of depreciation reasonable for new meters and other associated AMI costs?" While this issue is being addressed by OPC Witness Ron Binz, I have quantified the impact of Mr. Binz's recommendation. This quantification, which replaces the depreciation rate requested by Pepco of 6.67% (based on a 15 year life) with the current authorized rate for Account 370 of 2.75%, is presented on Exhibit OPC (B)-4, Schedule 14. The depreciation of the AMI meters at the currently authorized depreciation rate of 2.75% results in a $1,077,948 reduction to the depreciation expense incorporated in Pepco's filing and a $628,803 reduction to accumulated depreciation.

V. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. After thorough review of Pepco's testimony and discovery and analysis, I recommend an increase in electric distribution rates, giving effect to all adjustments quantified at this time, of $8,786,000, which is $33,737,000 less than the $42,523,000 increase requested by the Company.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT

County of Wayne)
State of Michigan) SS:

Donna Ramas, being first duly sworn, deposes and states that she is the Donna Ramas whose Testimony accompanies this Affidavit; that such testimony was prepared by her or under her supervision; that she is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of her knowledge, information and belief; and that she does adopt the same as true as her sworn testimony in this proceeding.

Donna Ramas

Donna Ramas

Subscribed and sworn before me this

9 day of December, 2011.

Hugh Larkin Jr

Notary Public

My Commission Expires:

NOTARY PUBLIC OFFICIAL SEAL STATE OF MICHIGAN

HUGH LARKIN JR.
Notary Public, State of Michigan
County of Wayne
My Commission Expires Sep. 13, 2013
Acting in the County of ____________

Exhibits of

OPC Witness

Donna Ramas

Exhibit OPC (B)-1

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Exhibit OPC (B)-1

Ratemaking Results and Revenue Requirement
Test Year Ended September 30, 2011
(Thousands of Dollars)

	Description	DC Test Year Per PEPCO	PEPCO Adjustments	PEPCO Adj. Before Increase	OPC Adjustments	DC Adjusted per OPC	Revenue Change to Achieve OPC's ROR	Adjusted to Reflect OPC's Rate of Return
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
	RATE BASE							
1	Electric Plant in Service	$ 2,380,818	$ 16,338	$ 2,397,156	$ (28,826)	$ 2,368,330		$ 2,368,330
2	Accumulated Depreciation	(845,691)	150	(845,541)	(258)	(845,799)		(845,799)
3	Accumulated Amortization	(27,677)	19,996	(7,681)	134	(7,547)		(7,547)
4	Materials & Supplies	20,597	-	20,597		20,597		20,597
5	Cash Working Capital	14,333	-	14,333	(1,574)	12,759		12,759
6	Accumulated Deferred Income Taxes	(474,502)	(8,492)	(482,994)	1,176	(481,818)		(481,818)
7	Prepaid Pension/OPEB Liability (Net of Tax)	45,862	3,764	49,626		49,626		49,626
8	Customer Deposits	(21,060)	-	(21,060)		(21,060)		(21,060)
9	PEPCO Portion of Serco Assets	4,929	1,900	6,829		6,829		6,829
10	Regulatory Assets	3,043	37,263	40,306	(6,367)	33,939		33,939
11	Unamortized Credit Facility Costs	-	454	454		454		454
		-	-	-		-		-
12	TOTAL RATE BASE	$ 1,100,652	$ 71,373	$ 1,172,025	$ (35,715)	$ 1,136,310	$ -	$ 1,136,310
	OPERATING REVENUES							
13	Sale of Electricity	$ 410,911	$ -	410,911		410,911		
14	Other Revenues	$ 3,224		3,224		3,224		
15	Total Operating Revenues	$ 414,135	$ -	$ 414,135	$ -	$ 414,135	$ 8,786	$ 422,921
	OPERATING EXPENSES							
16	Operation & Maintenance Expense	112,028	(6,473)	105,555	(1,001)	104,554		104,554
17	Depreciation Expense	59,290	409	59,699	(1,818)	57,881		57,881
18	Amortization Expense	3,519	6,499	10,018	(3,194)	6,824		6,824
19	Other Taxes	143,743	(2,183)	141,560	-	141,560		141,560
20	D.C. Income Tax	2,955	475	3,430	1,047	4,477	876	5,353
21	Federal Income Taxes	17,889	(396)	17,493	3,309	20,802	2,768	23,570
22	Total Operating Expenses	$ 339,424	$ (1,669)	$ 337,755	$ (1,657)	$ 336,098	$ 3,645	$ 339,743
23	Net Operating Income	$ 74,711	1,669	$ 76,380	1,657	$ 78,037	5,141	$ 83,178
24	RATE OF RETURN	6.79%		6.52%		6.87%		7.32%

Sources:
Columns (A) - (C): PEPCO (2F)-2, page 1
Columns (D): Exhibit OPC(B)-2

Exhibits of

OPC Witness

Donna Ramas

Exhibit OPC (B)-2

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Exhibit OPC (B)-2

Summary of OPC Adjustments
Test Year Ended September 30, 2011
(Thousands of Dollars)

OPC Sch. No.	OPC Adjustments	Rate Base	Operating Revenues	O&M Expenses	Depreciation Expense	Amortization Expense	Other Taxes	D.C. Income Taxes	Federal Income Taxes	Net Operating Income Effect
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Reduction to AMI Regulatory Asset - Incremental Costs					$ (268)		$ 27	$ 84	$ 157
	- Reduction to Regulatory Asset, Net of ADIT	$ (2,253)								
	- Reduction to Accumulated Amortization	134								
2	Remove NE Distribution and Substation Plant Adjustment									
	- Plant in Service	(12,464)			(307)			31	97	179
	- Accumulated Depreciation	153								
	- Accumulated Deferred Taxes	1,176								-
3	Reduction to Cash Working Capital	(1,574)								
4	Employee Health & Welfare Expense			(420)				42	132	246
5	Storm Damage Costs & Hurricane Irene Costs	(1,207)		(129)		(720)		85	267	497
6	Remove Non-Recurring Meter Expense, Account 586			(314)				31	99	184
7	Remove Accounts Receivable Write-Off			(44)				4	14	26
8	Remove Post-Test Year Flotation Costs	(355)				(404)		40	127	237
9/KM	Incremental Customer Care Exp - Energy Advisors & Engineers			(94)				9	30	55
10/KM	Reduction to Meter Blanket Capital Budget									
	- Plant in Service	(738)			(49)			5	15	29
	- Accumulated Depreciation	25								
11/KM	Reduction to Feeder Undergrounding Capital Budget									
	- Plant in Service	(2,887)			(71)			7	22	42
	- Accumulated Depreciation	36								
13	Reduction to Forecast Net Plant Additions									
	- Plant in Service	(12,737)			(313)			31	99	183
	- Accumulated Depreciation	157								
14/RB	Reduction to AMI Depreciation to Reflect Current Rates	(629)			(1,078)			108	340	630
NB	Reversal of Medicare OPEB Tax Subsidy Adjustment (RMA 9)	(209)				(145)		14	46	85
NB	Remove Severance Regulatory Asset and Amortization (RMA28)	(2,343)				(1,657)		165	522	970
12	Interest Synchronization							448	1,415	(1,863)
	TOTAL OPC ADJUSTMENTS	$ (35,715)	$ -	$ (1,001)	$ (1,818)	$ (3,194)	$ -	$ 1,047	$ 3,309	$ 1,657

Source/Notes:
KM - Adjustment sponsored by OPC witness Kevin Mara
RB - Adjustment sponsored by OPC witness Ron Binz
NB - Adjustment sponsored by OPC witness Nancy Bright

DC Income Tax Rate 9.975%
Federal Income Tax Rate 35.00%

Exhibits of

OPC Witness

Donna Ramas

Exhibit OPC (B)-3

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Revenue Requirements of Adjustments
Test Year Ended September 30, 2011
(Thousands of Dollars)

OPC Sch. No.	Description	Rate Base	Net Operating Income	Revenue Requirement Impact
	PEPCO Adjusted Amounts	$ 1,172,025	$ 76,380	
	PEPCO Revenue Requirement Increase at 8.64% Rate of Return			$ 42,523
	OPC Adjustments			
(a)	Reduction in revenue requirement at OPC's rate of return			(26,438)
1	Reduction to AMI Regulatory Asset - Incremental Costs	(2,119)	157	(533)
2	Remove NE Distribution & Substation Plant (RMA 43)	(11,135)	179	(1,699)
3	Reduction to Cash Working Capital	(1,574)		(197)
4	Employee Health & Welfare Expense		246	(420)
5	Storm Damage Costs & Hurricane Irene	(1,207)	497	(999)
6	Remove Non-Recurring Meter Expense, Account 586		184	(314)
7	Remove Accounts Receivable Write-Off		26	(44)
8	Remove Post-Test Year Flotation Costs	(355)	237	(449)
9/KM	Incremental Customer Care Exp - Energy Advisors & Engineers		55	(94)
10/KM	Reduction to Meter Blanket Capital Budget	(713)	29	(139)
11/KM	Reduction to Feeder Undergrounding Capital Budget	(2,851)	42	(428)
NB	Reversal of Medicare OPEB Tax Subsidy Adjustment (RMA 9)	(209)	85	(171)
NB	Remove Severance Regulatory Asset and Amortization (RMA 28)	(2,343)	970	(1,951)
12	Interest Synchronization Adjustment		(1,863)	3,184
13	Reduction to Forecast Net Plant Additions	(12,580)	183	(1,886)
14/RB	Reduction to AMI Depreciation to Reflect Current Rates	(629)	630	(1,155)
	Total OPC Adjustments	(35,715)	1,657	(33,737)
	Revenue Requirement at OPC's Recommended ROR	$ 1,136,310	$ 78,037	$ 8,786

Source/Notes:
(a) See Exhibit OPC(B)-3, Summary Schedules, Page 3 of 4.
KM - Adjustment sponsored by OPC witness Kevin Mara
RB - Adjustment sponsored by OPC witness Ron Binz
NB - Adjustment sponsored by OPC witness Nancy Bright

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Revenue Requirements of Adjustments
Test Year Ended September 30, 2011
(Thousands of Dollars)

	Description		Company As Filed Amount (A)	OPC Recommended Amount (B)
1	Adjusted Rate Base		$ 1,172,025	$ 1,136,310
2	Requested Rate of Return		8.64%	7.32%
3	Required Net Operating Income		$101,263	$83,178
4	Adjusted Net Operating Income Before Increase		76,380	78,037
5	Net Operating Income Deficiency / (Excess)		$24,883	$5,141
6	D.C. Income Tax		4,242	876
7	Federal Income Taxes		13,399	2,768
8	Total Revenue Deficiency		$ 42,523	$ 8,786
		Per PEPCO	Per OPC	
9	D.C. Income Tax at 9.975%	9.975%	9.975%	
10	Federal Income Tax at 35%	31.509%	31.509%	
11	Composite Tax Rate	41.484%	41.484%	
12	Compliment of Composite Tax Rate	58.516%	58.516%	
13	Revenue requirement factor	1.70893	1.70893	

Sources:

Column B, Line 2: Rate of Return recommended by OPC witness Randall Woolridge

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
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Revenue Requirement Impact of Rate of Return Adjustment
Test Year Ended September 30, 2011

	Description		Amount
1	Rate Base per PEPCO		$ 1,172,025
2	PEPCO Requested Rate of Return		8.64%
3	PEPCO Requested Net Operating Income	(Line 1 x Line 2)	$ 101,263
4	OPC Recommended Rate of Return		7.32%
5	Required Net Operating Income at OPC's Rate of Return	(Line 1 x Line 4)	$ 85,792
6	Decrease in Net Operating Income	(Line 5 - Line 3)	$ (15,471)
7	Revenue Requirement Factor		1.70893
8	Decrease in Revenue Requirement at OPC's Rate of Return	(Line 6 x Line 7)	$ (26,438)

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Revenue Requirements of Rate of Return Adjustment
Test Year Ended September 30, 2011

	Description	Capital Structure (A)	Cost Rates (B)	Weighted Cost Rate (C)	Revenue Requirement Factor (D)
1	Short-Term Debt	7.32%	1.00%	0.07%	
2	Long-Term Debt	45.36%	6.60%	2.99%	
3	Common Equity	47.31%	9.00%	4.26%	
4	Total Return, per OPC	100.00%		7.32%	
5	Revenue Requirement Factor (See page 2 of 4)				1.70893
6	Total Return Times Revenue Requirement Factor, per OPC				12.51%

Source/Notes:
The capital structure and cost rates presented above are sponsored by OPC witness J. Randall Woolridge and are provided above for convenience.

Exhibits of

OPC Witness

Donna Ramas

Exhibit OPC (B)-4

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Reduction to AMI Regulatory Asset - Incremental Costs
Test Year Ended September 30, 2011

Line No.	Description	Amount	Amount
1	AMI Incremental Post 2008 Costs, per OPC (See page 2 of 3)	$ 2,473	
2	AMI Incremental Post 2008 Costs, per PEPCO	6,412	
3	Reduction to Incremental Post-2008 Costs		$ (3,939)
4	Accumulated Capital Carrying Costs, per OPC (See page 2 of 3)	105	
5	Accumulated Capital Carrying Costs, PEPCO	187	
6	Reduction to Incremental Carrying Costs		(82)
7	Reduction to Regulatory Asset to be Recovered Over 15 Years (L.3 + L.6)		$ (4,021)
8	Reduction to Rate Base for Average Unamortized Balance		$ (3,887)
9	Adjustment to Rate Base for Accumulated Amortization		$ 134
10	Accumulated Deferred Taxes on Incremental Costs, per OPC (p.2)	(1,026)	
11	Accumulated Deferred Taxes on Incremental Costs, PEPCO	(2,660)	
12	Adjustment to Accumulated Deferred Taxes in Rate Base		$ 1,634
13	Reduction to Annual Amortization Expense (Line 7 / 15 years)		$ (268)

Source:
Per PEPCO amounts from Compliance Filing, Section 206.9, page 147

POTOMAC ELECTRIC POWER COMPANY
District of Columbia
Formal Case No. 1087

Exhibit OPC (B)-4
Schedule 1

Reduction to AMI Regulatory Asset - Incremental Costs
Test Year Ended September 30, 2011

		Reg Asset - Incremental Costs						
		Net Activity	Balance	ADT activity	ADT balance	ccrf activity	uncompounded ccrf	total balance
Jan-09	Act	590	590	(245)	(245)	1		345
Feb-09	Act	9,686	10,276	(4,018)	(4,263)	17		6,013
Mar-09	Act	1,307	11,583	(542)	(4,805)	35		6,778
Apr-09	Act	(5,023)	6,560	2,084	(2,721)	29		3,839
May-09	Act	14,518	21,078	(6,023)	(8,744)	44		12,334
Jun-09	Act	(2,778)	18,300	1,153	(7,591)	63	189	10,897
Jul-09	Act	3,448	21,748	(1,430)	(9,021)	65		12,915
Aug-09	Act	(12,624)	9,124	5,237	(3,784)	50		5,528
Sep-09	Act	14,595	23,719	(6,055)	(9,839)	53		14,069
Oct-09	Act	4,170	27,889	(1,730)	(11,569)	83		16,509
Nov-09	Act	12,800	40,689	(5,310)	(16,879)	110		23,999
Dec-09	Act	13,407	54,096	(5,562)	(22,441)	152	514	32,357
Jan-10	Act	13,129	67,225	(5,446)	(27,887)	197		40,040
Feb-10	Act	81,208	148,433	(33,688)	(61,575)	347		87,560
Mar-10	Act	(53,838)	94,595	22,334	(39,241)	391		56,056
Apr-10	Act	23,691	118,286	(9,828)	(49,069)	343		69,919
May-10	Act	127,419	245,705	(52,858)	(101,927)	583		144,480
Jun-10	Act	416,401	662,106	(172,739)	(274,666)	1,449	3,310	391,453
Jul-10	Act	4,031	666,137	(1,672)	(276,338)	2,137		393,812
Aug-10	Act	58,487	724,624	(24,263)	(300,601)	2,236		428,036
Sep-10	Act	136,348	860,972	(56,562)	(357,163)	2,546		507,822
Oct-10	Act	141,346	1,002,318	(58,636)	(415,799)	2,988		590,532
Nov-10	Act	(82,227)	920,091	34,111	(381,688)	3,083		542,416
Dec-10	Act	37,772	957,863	(15,669)	(397,357)	3,012	16,002	580,520
Jan-11	Act	66,959	1,024,822	(27,777)	(425,134)	3,266		619,702
Feb-11	Act	65,136	1,089,958	(27,021)	(452,155)	3,476		657,817
Mar-11	Act	91,311	1,181,269	(37,879)	(490,034)	3,725		711,249
Apr-11	Act	71,705	1,252,974	(29,746)	(519,780)	3,985		753,208
May-11	Act	152,368	1,405,342	(63,208)	(582,988)	4,341		842,368
Jun-11	Act	85,826	1,491,168	(35,604)	(618,592)	4,721	23,513	916,103
Jul-11	Act	65,793	1,556,961	(27,294)	(645,886)	5,090		954,602
Aug-11	Act	218,698	1,775,660	(90,724)	(736,610)	5,543		1,082,577
Sep-11	Act	90,863	1,866,523	(37,693)	(774,303)	6,036		1,135,747
Oct-11	Act	160,139	2,026,662	(66,432)	(840,735)	6,435		1,229,454
Nov-11	REV	118,775	2,145,437	(49,272)	(890,007)	6,879		1,298,957
Dec-11	REV	117,642	2,263,079	(48,802)	(938,809)	7,256	37,239	1,405,036
Jan-12	REV	87,564	2,350,643	(36,325)	(975,134)	7,785		1,456,275
Feb-12	REV	60,569	2,411,212	(25,126)	(1,000,260)	8,021		1,491,718
Mar-12	REV	61,781	2,472,993	(25,629)	(1,025,889)	8,216	24,022	1,551,892
Totals		**2,472,993**		**(1,025,889)**		**104,788**		1,551,892

Source: PEPCO Response to OPC Data Request 14, Question 5, with the exception of November 2011 - March 2012 Revised Amounts. See page 3 of 3 for calculation of revised November 2011 - March 2012 projections.

POTOMAC ELECTRIC POWER COMPANY
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Reduction to AMI Regulatory Asset - Incremental Costs
Test Year Ended September 30, 2011

Incremental Costs Worksheet

Line	Description	Actual Costs	Projected In Filing	Difference
1	April 2011	$ 71,705	$ 392,358	$ (320,653)
2	May 2011	152,368	403,827	(251,459)
3	June 2011	85,826	476,175	(390,349)
4	July 2011	65,793	552,955	(487,162)
5	August 2011	218,698	566,418	(347,720)
6	September 2011	90,863	550,460	(459,597)
7	October 2011	160,139	480,941	(320,802)
8	Total April 2011 - October 2011	$ 845,392	$ 3,423,134	$ (2,577,742)
9	April 2011 - October 2011 % of Budget Spent			24.70%
		Per PEPCO Budgeted Amount	Revised per OPC Based on % Budget Spent	Difference
			24.70%	
10	November 2011	$ 480,941	$ 118,775	$ (362,166)
11	December 2011	476,351	117,642	(358,709)
12	Janaury 2012	354,560	87,564	(266,996)
13	February 2012	245,254	60,569	(184,685)
14	March 2012	250,161	61,781	(188,380)
15	Nov 2011 - March 2012 Additions	$ 1,807,267	$ 446,331	$ (1,360,936)
16	Reduction to Reflect Actual AMI Incremental Costs, Apr 2011 - Oct 2011			$ (2,577,742)
17	Reduction to Projected Nov. 2011 - Mar 2012 based on prior variance			(1,360,936)
18	Reduction to Projected AMI Incremental Cost Deferral, per OPC			$ (3,938,678)

Source:
Actual Costs per response to OPC Data Request 14, Question 5
Projected amounts in filing from Compliance Filing Section 206.9, page 147.

POTOMAC ELECTRIC POWER COMPANY
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Exhibit OPC (B)-4
Schedule 2

Remove Northeast Distribution & Substation Adjustment
Test Year Ended September 30, 2011
(Thousands of Dollars)

Line No.	Description	Amount
1	Remove D.C. Electric Plant in Service	$ (12,464)
2	Remove D.C. Accumulated Depreciation	$ 153
3	Remove D.C. Accumulated Deferred Taxes	$ 1,176
4	Remove Adjustment to D.C. Depreciation Expense	$ (307)
5	Remove Adjusmtent to D.C. Income Tax Expense	$ 31
6	Remove Adjustment to Federal Income Tax Expense	$ 97

Source/Notes:
The above adjustment reverses PEPCO Ratemaking Adjustment 43.
PEPCO(2F)-2, page 47 of 52.

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Exhibit OPC (B)-4
Schedule 3

Cash Working Capital Adjustment
Test Year Ended September 30, 2011

	Description	DC Amount	Lag Days	Annual Lag Dollars
	Operating Expenses			
1	PEPCO Labor - Wages	$ 22,483,711	11.20	$ 251,817,563
2	Other Operating Expenses	76,640,991	37.57	2,879,402,032
3	Control Center Lease	2,885,929	90.75	261,898,057
4	Other Taxes			
5	Property Tax - DC	7,708,856	83.50	643,689,476
6	Property Tax - MD Montgomery	513,910	60.50	31,091,555
7	Property Tax - MD Prince George's	453,007	(90.50)	(40,997,134)
8	Property Tax - MD Charles	14,412	(59.50)	(857,514)
9	Property Tax - MD Other	51,297	(90.50)	(4,642,379)
10	Property Tax - VA Alexandria	90,246	51.00	4,602,546
11	Property Tax - VA Arlington	17,054	139.50	2,379,033
12	Property Tax - VA Fairfax	765	220.50	168,683
13	Property Tax - VA Pr William	3,683	75.50	278,067
14	DC Business Improvement Tax	157,760	(92.75)	(14,632,240)
15	DC Income Tax (current portion)	984,712	58.95	58,048,772
16	DC PSC Reimbursement	5,453,604	174.50	951,653,898
17	DC PSOS	21,569,222	(44.13)	(951,849,767)
18	DC RETF	17,897,759	35.71	639,128,974
19	DC Delivery Tax	88,091,806	35.71	3,145,758,392
20	DC Use Tax	(56,752)	35.71	(2,026,614)
21	Payroll Taxes - Federal Unemployment	17,102	(55.50)	(949,161)
22	Payroll Taxes - DC Unemployment	50,968	(54.85)	(2,795,595)
23	Payroll Taxes - MD Unemployment	33,879	(54.91)	(1,860,296)
24	FICA - Social Security	1,674,077	13.73	22,985,077
25	Federal Income Tax, per OPC Revised	17,493	58.95	1,031,212
26	Total Distribution Expenses	$ 246,755,491		$ 7,873,322,637
27	Composite Lag Days in Expenses		31.91	
28	Revenue Lag Days, per OPC		50.66	
29	Net Lag (Line 28 - Line 27)		18.75	
30	D.C Average Daily Expense		$ 676,042	
31	Cash Working Capital Allowance (Line 29 x Line 30)			$ 12,677,563
32	Less: FIT/FICA Withholding	12,036	2.7300	(32,858)
33	Less: State Withholding	2,587	26.5200	(68,607)
34	Subtotal			12,576,098
35	Add: Imprest Funds			183,162
36	Cash Working Capital, per OPC			12,759,260
37	Cash Working Capital, per PEPCO			14,333,194
38	Adjustment to Cash Working Capital			$ (1,573,934)

Source/Notes:
PEPCO (2F)-2, page 51 of 52
Recommended modifications shown on Lines 25 and 28, which are discussed in testimony.